January 26, 2012

12-ATMG-564-RTS

VIA HAND DELIVERY

Ms. Patrice Petersen-Klein
Executive Director
Kansas Corporation Commission
1500 S. W. Arrowhead Road
Topeka, Kansas 66604-4027

Re: Application of Atmos Energy Corporation

Dear Ms. Petersen-Klein:

Atmos Energy Corporation hereby transmits an original and nine copies of its Application for Adjustment of its Natural Gas Rates in the State of Kansas, together with an electronic copy of the Application, all in accordance with K.A.R. 82-1-231.

Thank you for your consideration.

Sincerely,

Karen P. Wilkes

Karen P. Wilkes

Enclosures (x)
cc: James G. Flaherty

Atmos Energy Corporation
Kansas Distribution System
Filing Schedules Index

2012.01.26 14:15:06
Kansas Corporation Commission
/S/ Patrice Petersen-Klein

Received
JAN 26 2012
by
State Corporation Commission
of Kansas

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

APPLICATION

COMES NOW Atmos Energy ("Atmos"), and files this Application to make changes in its charges for natural gas service under K.S.A. 66-117, K.S.A. 66-1,200, *et seq*., and K.A.R. 82-1-231. In support thereof, Atmos respectfully states:

1. Atmos is a natural gas public utility operating in the State of Kansas pursuant to certificates of convenience and necessity issues by the State Corporation Commission of the State of Kansas ("Commission"). Atmos' principal place of business within the State of Kansas is located at 25090 W. 110th Terr., Olathe, Kansas 66061.

2. Pleadings, notices, orders and other correspondence and communication regarding this Application should be sent to:

Douglas C. Walther
Associate General Counsel
Atmos Energy
P. O. Box 650205
Dallas, Texas 75265-0205
Douglas.Walther@AtmosEnergy.com

James Price
Attorney
Atmos Energy
P. O. Box 650205
Dallas, Texas 75265-0205
James.Price@AtmosEnergy.com

Karen P. Wilkes
Division Vice President, Regulatory and Public Affairs
Atmos Energy
1555 Blake Street, Suite 400
Denver, Colorado 80202

Karen.Wilkes@AtmosEnergy.com

Barton W. Armstrong
Vice President, Operations
Atmos Energy
25090 W. 110th Terr.
Olathe, Kansas 66061
Bart.Armstrong@AtmosEnergy.com

James G. Flaherty
Anderson & Byrd, LLP
216 S. Hickory, P. O. Box 17
Ottawa, Kansas 66067
jflaherty@andersonbyrd.com

3. Atmos provides retail natural gas service to approximately 128,502 customers in Kansas, including natural gas service to 106 communities and 2 unincorporated irrigation customers in 32 counties. Atmos filed its last rate case in January 2010, in Docket No. 10-ATMG-495-RTS ("495 Docket"). That rate case filing was based upon a test year that ended September 30, 2009. Several factors make the filing of this rate application necessary at this time. Atmos has made a significant investment in plant since its last rate case filing, including the largest single construction project since Atmos began operating in Kansas, the replacement of an 11-mile, 8-inch pipeline between College Boulevard and 199th Street along Pflumm Road in southern Overland Park, Kansas ("Pflumm Line Project"). Although Atmos has aggressively managed expenses, it has also experienced increases in wages, medical expenses, material and supplier costs. This Application supports Atmos' request for an increase in its revenue requirement.

4. The testimony of 8 witnesses and the schedules required by K.A.R. 82-1-231 are filed in support of this Application. The testimony and schedules show that as of September 30, 2011, Atmos' adjusted rate base for Kansas operations was $160,074,634. The earned return on Kansas gas operations investment was 2.72%. The schedules filed with this Application establish a gross revenue deficiency of $9.7 million based upon normalized operating results for the 12 months

ended September 30, 2011, adjusted for known and determinable changes in revenues, operating and maintenance expenses, cost of capital and taxes.

5. Presently effective rates do not produce sufficient revenues to cover the reasonable cost of Atmos' continued ability to render reasonably sufficient and efficient service. The existing retail natural gas rates of Atmos are unjust and unreasonable in that its jurisdictional earnings are deficient. Atmos must earn a reasonable return on its property dedicated to public service in order to acquire necessary capital at reasonable rates, carry out new construction, provide adequate gas supplies of gas and render the quality of service the public requires. The percent return to Atmos is not just and reasonable. Atmos' proposal to increase its revenues will result in an overall rate of return of 8.78%.

6. Atmos is filing a new depreciation study and is seeking new depreciation rates as part of this Application.

7. With respect to rate design, Atmos is proposing a traditional two part rate design with an increase in the monthly facility charge, which as explained by Gary L. Smith in his testimony, will more appropriately provide for recovery of fixed utility costs.

8. Atmos is also seeking approval to implement an annual rate adjustment provision, which will allow rates to be adjusted on an annual basis following this rate case. As set forth in the testimony of Gary L. Smith, the annual rate adjustment provision will provide a structure for regular, consistent and financially transparent rate review that would be conducted at a very low cost and assures that customers only pay the most current and appropriate rate.

9. The total adjustment in rates requested in this Application is just and reasonable and in the public interest. The request to change Atmos' schedules of charges is proposed to allow Atmos to maintain financial integrity and to permit it to continue to make capital investment in its distribution system for the benefit of the public.

10. Atmos has on file with the Commission certain schedules of charges and rates for its natural gas service. Atmos desires to withdraw certain of the schedules and file new ones in accordance with Section 18 filed in support of this Application. The charges reflect the effects of the requested revenue increase and the proposed changes in rate design and General Terms and Conditions. Atmos proposes that the revised schedules become effective thirty (30) days from the date of this filing, as permitted by law, or at such other date as the Commission may by order prescribe.

WHEREFORE, Atmos Energy respectfully requests the approval and consent of the Commission to withdraw and cancel its natural gas rate schedules and other provisions of its tariffs and to substitute therefore and place in effect the rate schedules and other provisions contained in Section 18 of the Application, which will provide a gross annual revenue increase of $9,705,116; and authorize the implementation of an annual cost adjustment provision.

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
Attorneys for Atmos Energy

VERIFICATION

STATE OF KANSAS)
) ss:
COUNTY OF FRANKLIN)

James G. Flaherty, being duly sworn on oath, states: That he is an attorney for Atmos Energy; that he has read and is familiar with the foregoing Application, knows the contents thereof; and that the statements contained therein are true and correct.

James G. Flaherty

SUBSCRIBED AND SWORN to before me this 20 day of January, 2012.

NOTARY PUBLIC – State of Kansas
RONDA ROSSMAN
My Appt. Expires 5/25/2014

Ronda Rossman

Notary Public

Appointment/Commission Expires:

ATMOS energy

News Release

Media Contact:
Jim Bartling
(913) 254-6321

Atmos Energy Files to Increase Kansas Rates

Olathe, Kan. (January 26, 2012)—Atmos Energy Corporation (NYSE: ATO) filed today with the Kansas Corporation Commission for a $9.7 million increase in annual revenues for its Kansas natural gas utility operations. Atmos Energy's last rate case was filed in January 2010 and was based upon operating costs for the 12 months ended September 30, 2009.

"It has been two years since our Kansas operation last requested a rate increase," said Bart Armstrong, operations vice president of Atmos Energy's Kansas region. "Since that time, we have experienced increases in our operating costs, and we have made a significant investment in plant."

If approved, the average monthly bill for residential customers in Kansas will increase $5.36 per month, or 21.7 percent. For commercial customers, the average monthly bill will increase $14.25, or 19.6 percent.

"The proposed increase should allow Atmos Energy to establish new rates that will provide a reasonable return to attract the capital needed to make necessary additions, replacements and improvements to help ensure the safety and reliability of our distribution system in Kansas," Armstrong said.

Atmos Energy serves approximately 128,000 natural gas customers in 106 communities in Kansas.

Forward-Looking Statements
The matters discussed in this news release may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this news release are forward-looking statements made in good faith by the company and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this news release or in any of the company's other documents or oral presentations, the words "anticipate," "believe," "estimate," "expect," "forecast," "goal," "intend," "objective," "plan," "projection," "seek," "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those discussed in this news release, including the risks and uncertainties relating to regulatory trends and decisions, the company's ability to continue to access the capital markets and the other factors discussed in the company's filings with the Securities and Exchange Commission. These factors include the risks and uncertainties discussed in the company's Annual Report on Form 10-K for the fiscal year ended September 30, 2009. Although the company believes these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, the company undertakes no obligation to update or revise any of its forward-looking statements, whether as a result of new information, future events or otherwise.

About Atmos Energy
Atmos Energy Corporation, headquartered in Dallas, is one of the country's largest natural-gas-only distributors, serving more than 3 million natural gas distribution customers in more than 1,600 communities in 12 states from the Blue Ridge Mountains in the East to the Rocky Mountains in the West. Atmos Energy also provides natural gas marketing and procurement services to industrial, commercial and municipal customers primarily in the Midwest and Southeast and manages company-owned natural gas pipeline and

storage assets, including one of the largest intrastate natural gas pipeline systems in Texas. Atmos Energy is a Fortune 500 company. For information, visit www.atmosenergy.com.

###

Atmos Energy Corporation
Kansas Distribution System
Section Two Summary

Section 2A

Line No.	County	City	County	City
1	**Section 2 (ii) - Communities affected:**			
2	County	City	County	City
3	Allen	Elsmore	Marion	Florence
4	Allen	Savonburg	Marion	Hillsboro
5	Barber	Hazelton	Marion	Lincolnville
6	Bourbon	Fort Scott	Marion	Lost Springs
7	Bourbon	Fulton	Marion	Marion
8	Bourbon	Hammond	Marion	Marion Lake
9	Bourbon	Redfield	Marion	Peabody
10	Chase	Cottonwood Falls	Marion	Pilsen
11	Chase	Strong City	Marion	Ramona
12	Chautauqua	Cedar Vale	Marion	Tampa
13	Chautauqua	Chautauqua	Miami	Hillsdale
14	Chautauqua	Elgin	Montgomery	Caney
15	Chautauqua	Hewins	Montgomery	Coffeyville
16	Chautauqua	Niotaze	Montgomery	Dearing
17	Chautauqua	Peru	Montgomery	Elk City
18	Chautauqua	Sedan	Montgomery	Havana
19	Coffey	Burlington	Montgomery	Independence
20	Coffey	LeRoy	Montgomery	Liberty
21	Coffey	New Strawn	Montgomery	Sycamore
22	Crawford	McCune	Montgomery	Tyro
23	Dickinson	Herington	Morris	Council Grove
24	Douglas	Eudora	Morris	Delavan
25	Douglas	Lawrence	Morris	White City
26	Elk	Elk Falls	Morris	Wilsey
27	Elk	Grenola	Morton	Unincorporated Irrigation
28	Elk	Longton	Neosho	Galesburg
29	Elk	Moline	Neosho	Morehead
30	Grant	Hickock	Neosho	Stark
31	Grant	Ulysses	Neosho	Thayer
32	Greenwood	Eureka	Ness	Bazine
33	Greenwood	Fall River	Ness	Ness City
34	Greenwood	Hamilton	Rush	Alexander
35	Greenwood	Neal	Rush	McCracken
36	Hamilton	Kendall	Stanton	Johnson City
37	Hamilton	Syracuse	Stanton	Manter
38	Harper	Anthony	Stevens	Unincorporated Irrigation
39	Harper	Danville	Sumner	Caldwell
40	Johnson	De Soto	Sumner	Hunnewell
41	Johnson	Gardner	Sumner	South Haven
42	Johnson	Lenexa	Wilson	Altoona
43	Johnson	New Century	Wilson	Benedict
44	Johnson	Olathe	Wilson	Buffalo
45	Johnson	Overland Park	Wilson	Fredonia
46	Johnson	Shawnee	Wilson	LaFontaine
47	Johnson	Spring Hill	Wilson	Neodesha
48	Labette	Bartlett	Woodson	Toronto
49	Labette	Chetopa	Woodson	Yates Center
50	Labette	Edna	Wyandotte	Bonner Springs
51	Labette	Mound Valley	Wyandotte	Edwardsville
52	Leavenworth	Basehor	Wyandotte	Kansas City
53	Leavenworth	Easton		
54	Leavenworth	Jarbalo		
55	Leavenworth	Leavenworth		
56	Leavenworth	Linwood		
57	Linn	Mound City		
58	Linn	Pleasanton		
59	Linn	Prescott		
60	Marion	Aulne		

Atmos Energy Corporation
Kansas Distribution System
Section Two Summary

Section 2B

Section 2 (iii) - Number and Classification of Customers

Residential	117,869
Commercial	9,975
Industrial	20
Irrigation	272
Transportation	366
	128,502

Section 2 (i) and (iv) - Aggregate Annual Increase and Average Per Customer Increase [1]

	Present	Proposed	Increase	Avg.
Residential	$ 34,938,286	$42,524,271	$ 7,585,985	$ 64
Commercial	8,716,224	10,421,769	1,705,545	171
Industrial	129,829	155,307	25,478	1,274
Irrigation	759,819	911,670	151,851	558
Transportation	3,888,023	4,540,333	652,310	1,782
Other Revenue	1,100,136	684,475	(415,660)	
Rounding			(392)	
	$ 49,532,317	$59,237,825	$ 9,705,116	$76
			(i)	**(iv)**

[1] Please see Section 17, Columns m and p.

Section 2 (v)

Increase in property, plant & equipment, associated depreciation & tax expense and increase in operations and maintenance costs.

Atmos Energy Corporation
Kansas Distribution System
Summary of Rate Base, Operating Income and Rate of Return
Test period ended September 30, 2011

Line No.	Description	Reference		Total Adjusted KS Juris
	(a)	(b)		(c)
1	Rate Base:			
2	Plant In Service	Section 4	$	268,500,779
3	Accumulated Depreciation	Section 5		(99,827,232)
4	Net Plant in Service	(Ln. 2+3)	$	168,673,547
5	Construction Work in Progress	Section 14A	$	18,782,485
6				
7	Working Capital	Section 6		
8	Prepayments		$	651,845
9	Storage Gas			11,175,793
10	Cash Requirements			0
11	Total Working Capital	(Ln. 8+9+10)	$	11,827,637
12				
13	Rate Base Deductions	Section 14A		
14	Customer Advances for Construction		$	(1,065,228)
15	Customer Deposits			(2,455,902)
16	Accumulated Deferred Income Tax			(35,687,906)
17	Total Rate Base Deductions	(Ln. 14+15+16)	$	(39,209,036)
18				
19	Total Rate Base	(Ln. 4+5+11+17)	$	160,074,634
20				
21	Rate of Return on Rate Base, Proposed	Section 7		8.78%
22				
23	Return on Rate Base	(Ln. 19 * Ln. 21)	$	14,060,342
24	Operation & Maintenance Expense	Section 9		18,684,894
25	Depreciation & Amortization Expense	Section 10		13,347,372
26	Taxes Other Than Income Taxes	Section 11		7,238,894
27	Interest on Customer Deposits	Section 14C		2,947
28	Income Tax	Section 11		5,902,984
29				
30	Total Cost of Service	(Sum of Lns. 23-28)	$	59,237,433
31				
32	Margin Revenue at Present Rates	Section 17	$	49,532,317
33				
34	Revenue Increase Required	(Ln. 30-32)	$	9,705,116

Atmos Energy Corporation
Kansas Distribution Systems
Including Summary of Adjustments
Twelve Months Ended September 30, 2009

Line No.	Description	Reference	Kansas Unadjusted	IS-1 WP 9-2 Labor	IS-2 WP 9-3 Benefits	IS-3 WP 9-4 AGA Dues	IS-4 WP 9-5 50% of Charitable Contributions	IS-5 WP 9-6 Amortization of Rate Case Expenses	IS-6 WP 9-7 Expense Rpt Adjustment	IS-7 Sch 10 Depreciation Adjustment	IS-8 WP 11-2 Ad Valorem Adjustment Current	IS-9 WP 11-4 Ad Valorem Adjustment CWIP	IS-10 WP 11-5 Payroll Tax
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Rate Base:												
2	Plant In Service	Section 4	$ 268,500,779										
3	Accumulated Depreciation	Section 5	$ (99,827,232)										
4	Net Plant in Service	(Ln1-2)	$ 168,673,547	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Construction Work in Progress	Section 14A	$ 6,821,140										
6													
7	Working Capital	Section 6											
8	Prepayments	Section 6	$ 651,845										
9	Cash Requirements	Section 6	$ -										
10	Storage Gas	Section 6	$ 11,175,793										
11	Total Working Capital	(Ln8+9+10)	$ 11,827,637	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12													
13	Rate Base Deductions	Section 14A											
14	Accumulated Deferred Income Tax	Section 14A	$ (38,767,208)										
15	Customer Advances for Construction	Section 14A	$ (1,065,228)										
16	Customer Deposits	Section 14A	$ (2,455,902)										
17	Total Rate Base Deductions		$ (42,288,338)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18													
19	Total Rate Base	(Ln4+5+11+17)	$ 145,033,986	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20													
21	Rate of Return on Rate Base	Section 7	8.78%										
22													
23	Return on Rate Base	(Ln19xLn21)	$ 12,739,229	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Operation & Maintenance Expense	Section 9	$ 18,108,292	$ 212,613	$ 82,670	$ (7,203)	$ 78,707	$ 210,000	$ (69,720)				
25	Depreciation & Amortization Expense	Section 10	$ 9,725,275							$ 3,622,098			
26	Taxes Other Than Income Taxes	Section 11	$ 6,515,265								$ 147,536	$ 538,384	$ 69,574
27	Interest on Customer Deposits	Section 14C	$ 11,995										
28	Income Tax	Section 11B	$ 5,348,102										
29													
30	Total Cost of Service	(Sum Lns 23-28	$ 52,448,157	$ 212,613	$ 82,670	$ (7,203)	$ 78,707	$ 210,000	$ (69,720)	$ 3,622,098	$ 147,536	$ 538,384	$ 69,574
31													
32	Margin at Present Rates	Section 17	$ 49,398,599										
33													
34	Revenue Increase Required	(Ln30-32)	$ 3,049,558	$ 212,613	$ 82,670	$ (7,203)	$ 78,707	$ 210,000	$ (69,720)	$ 3,622,098	$ 147,536	$ 538,384	$ 69,574

Line No.	Description	Reference	IS-11 WP 11-6 KCC Assessment	IS-12 Sch 11B Income Tax Adjustment	IS-13 Sch 14C Interest on Customer Deposits	IS-14 WP 17-2, WP 17-4 Weather/ Large Vol Cust Adjustment	IS-15 WP 9-9 Pen/Post Ret Benefits Adjustment	RB-1 WP 14-1 Long-term CWIP Adjustment	RB-2 WP 14-4 ADIT Adjustment	Adjusted Kansas
	(a)	(b)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	Rate Base:									
2	Plant In Service	Section 4								$ 268,500,779
3	Accumulated Depreciation	Section 5								$ (99,827,232)
4	Net Plant in Service	(Ln1-2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 168,673,547
5	Construction Work in Progress	Section 14A						$ 11,961,346		$ 18,782,485
6										
7	Working Capital	Section 6								$ -
8	Prepayments	Section 6								$ 651,845
9	Cash Requirements	Section 6								$ -
10	Storage Gas	Section 6								$ 11,175,793
11	Total Working Capital	(Ln8+9+10)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,827,637
12										
13	Rate Base Deductions	Section 14A								
14	Accumulated Deferred Income Tax	Section 14A							$ 3,079,302	$ (35,687,906)
15	Customer Advances for Construction	Section 14A								$ (1,065,228)
16	Customer Deposits	Section 14A								$ (2,455,902)
17	Total Rate Base Deductions		$ -	$ -	$ -	$ -	$ -	$ -	$ 3,079,302	$ (39,209,036)
18										
19	Total Rate Base	(Ln4+5+11+17)	$ -	$ -	$ -	$ -	$ -	$ 11,961,346	$ 3,079,302	$ 160,074,634
20										
21	Rate of Return on Rate Base	Section 7								8.78%
22										
23	Return on Rate Base	(Ln19xLn21)	$ -	$ -	$ -	$ -	$ -	$ 1,050,639	$ 270,474	$ 14,060,342
24	Operation & Maintenance Expense	Section 9					$ 69,534			$ 18,684,894
25	Depreciation & Amortization Expense	Section 10								$ 13,347,372
26	Taxes Other Than Income Taxes	Section 11	$ (31,865)							$ 7,238,894
27	Interest on Customer Deposits	Section 14C			$ (9,048)					$ 2,947
28	Income Tax	Section 11B		$ 554,883						$ 5,902,984
29										
30	Total Cost of Service	(Sum Lns 23-28	$ (31,865)	$ 554,883	$ (9,048)	$ -	$ 69,534	$ 1,050,639	$ 270,474	$ 59,237,433
31										
32	Margin at Present Rates	Section 17				$ 133,717	$ -			$ 49,532,317
33										
34	Revenue Increase Required	(Ln30-32)	$ (31,865)	$ 554,883	$ (9,048)	$ (133,717)	$ 69,534	$ 1,050,639	$ 270,474	$ 9,705,117

Atmos Energy Corporation
Kansas Distribution Systems
Functional Plant in Service Acct 101 - Kansas Direct and Allocated
Balance as of September 30, 2011

Line No.	Description	Property Type	Liberty Div 79	Kansas Div 81	Southwest Div Div 86	Asset Transfers (1)	Adjustment Reclass (2)	Total Kansas
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Intangible Plant							
1	Franchises & Consents	30200	$ -	$ 37,160	$ -			$ 37,160
2	Misc. Intangible Plant	30300	-	3,918	-			3,918
3	Total Intangible Plant		$ -	$ 41,078	$ -	$ -	$ -	$ 41,078
4								
5	**Underground Storage**							
6	Land	35010	$ 49,164	$ -	$ -			$ 49,164
7	Rights-of-way	35020	568,935	-	-			568,935
8	Well Structures	35100	102,923	-	-			102,923
9	Wells	35200	1,136,225	-	-			1,136,225
10	Reservoirs	35202	36,515	-	-			36,515
11	Leaseholds	35210	-	-	-			-
12	Pipelines	35300	1,090,230	-	-	$ 55,588		1,145,818
13	Compressor Station Equipment	35400	2,259,430	-	-			2,259,430
14	Meas. & Reg. Equipment	35500	220,011	-	-			220,011
15	Purification Equipment	35600	288,382	-	-			288,382
16	Other Equip	35700	167,513	-	-	(42,191)		125,321
17	Total Underground Storage Plant		$ 5,919,327	$ -	$ -	$ 13,397	$ -	$ 5,932,723
18								
19	**Transmission Plant**							
20	Land and Land Rights	36500	$ -	$ 4,761	$ 6,490			$ 11,252
21	Rights-of-way	36520	-	-	9,037			9,037
22	Structures & Improvements	36600	-	-	33,191			33,191
23	Mains Cathodic Protection	36700	-	1,617,348	1,861,506		$ (25,950)	3,452,904
24	Mains Steel	36701	-	139,979	3,474			143,453
25	Anodes	36703					2,795	2,795
26	Leak Clamps & Sleeves	36704					23,155	23,155
27	Compressor Station Equipment	36800	-	-	31,496			31,496
28	Meas. & Reg. Sta. Equipment	36900	-	148,706	377,522			526,227
29	Other Equipment	37100	-	-	-			-
30	Total Transmission Plant		$ -	$ 1,910,794	$ 2,322,717	$ -	$ -	$ 4,233,511
31								
32	**Distribution Plant**							
33	Land & Land Rights	37400	$ -	$ 650,876	$ 20,107			$ 670,983
34	Land Rights	37402	-	286,730	5,873			292,603
35	Structures & Improvements	37500	-	119,134	360			119,494
36	Mains Cathodic Protection	37600	-	8,182,975	589,833		$ (4,593,678)	4,179,130
37	Mains Steel	37601	-	34,184,581	3,682,507		(5,061,965)	32,805,123
38	Mains Plastic	37602	-	76,174,834	2,724,253			78,899,087
39	Anodes	37603					3,059,067	3,059,067
40	Leak Clamps & Sleeves	37604					6,596,575	6,596,575
41	Meas. & Reg. Sta. Eq-General	37800	-	3,313,148	218,169	$ 39,960		3,571,277
42	Meas. & Reg. City Gate	37900	-	2,192,034	6,518	9,260		2,207,812
43	Meas. & Reg. Sta. Equipment-	37908	-	-	14,851			14,851
44	Services	38000	-	53,677,076	3,958,059			57,635,135
45	Meters	38100	-	14,184,666	836,477			15,021,142
46	Meter Installations	38200	-	22,001,839	1,915,964			23,917,803
47	House Regulators	38300	-	2,145,570	64,228			2,209,798
48	House Reg. Installations	38400	-	203,477	5,985			209,461
49	Ind. Meas. & Reg. Sta. Equip	38500	-	875,840	60,014	15,551		951,405
50	Other Equipment	38700	-	10,034	8,202	595,519		613,755
51	Total Distribution Plant		$ -	$ 218,202,813	$ 14,111,399	$ 660,291	$ -	$ 232,974,503
52								

Atmos Energy Corporation
Kansas Distribution Systems
Functional Plant in Service Acct 101 - Kansas Direct and Allocated
Balance as of September 30, 2011

Line No.	Description	Property Type	Liberty Div 79	Kansas Div 81	Southwest Div Div 86	Asset Transfers (1)	Adjustment Reclass (2)	Total Kansas
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
53	**Direct General Plant**							
54	Land & Land Rights	38900	$ -	$ 152,535	$ -			$ 152,535
55	Structures & Improvements	39000	-	1,787,101	66,567			1,853,668
56	Improvements	39003	-	1,513	-			1,513
57	Air Conditioning Equipment	39004	-	-	8,782			8,782
58	Improv. to Leased Premises	39009	-	39,013	-			39,013
59	Office Furniture & Equipment	39100	-	411,635	-	$ 18,575		430,210
60	Office Furn. Copiers & Type	39103	-	-	5,220			5,220
61	Transportation Equipment	39200	-	266,687	7,815	370,799		645,302
62	Stores Equipment	39300	-	1,308	-			1,308
63	Tools, Shop, & Garage Equip.	39400	7,047	1,949,357	135,461	473,184		2,565,050
64	Laboratory Equipment	39500	-	5,233	3,056	12,933		21,223
65	Power Operated Equipment	39600	-	389,595	43,927	57,441		490,962
66	Ditchers	39603	-	67,799	33,393			101,192
67	Backhoes	39604	-	203,475	-			203,475
68	Welders	39605	-	54,819	-			54,819
69	Communication Equipment	39700	-	380,223	25,032	5,623		410,879
70	Comm. Equip. Mobile Radios	39701	-	-	-	7,902		7,902
71	Comm. Equip. Fixed Radios	39702	-	-	-	6,065		6,065
72	Miscellaneous Equipment	39800	-	1,594,048	12,147	(1,599,119)		7,076
73	Other Tangible Property	39900	-	27,091	-	(27,091)		-
74	Oth Tang Prop - Servers - H/W	39901		25,349				25,349
75	Oth Tang Prop - Servers - S/W	39902	-	63,702	-			63,702
76	Oth Tang Prop Network H/W	39903	-	180,428	-			180,428
77	Oth Tang Prop PC Hardware	39906	-	1,117,300	15,269			1,132,569
78	Oth Tang Prop PC Software	39907	-	84,070	-			84,070
79	Oth Tang Prop Appl Software	39908	-	213,445	-			213,445
80	Total Direct General Plant		$ 7,047	$ 9,015,726	$ 356,669	$ (673,687)	$ -	$ 8,705,755
81								
82	**Total Kansas Direct Gross Plant**		$ 5,926,374	$ 229,170,412	$ 16,790,784	$ (0)	$ -	$ 251,887,570
83								
84	General Plant Alloc from Shared Services	WP 4-2						$ 6,584,416
85	General Plant Alloc from Customer Support	WP 4-3						8,343,802
86	General Plant Alloc from CO/KS Gen Office	WP 4-4						1,684,990
87								
88	**Total KS Direct and Allocated Gross Plant**							$ 268,500,779
89								

90 Notes:
91 1. Based upon the review of plant assets, it was determined a reclassification of certain assets was required.
92 2. Anodes and leak clamps/sleeves have been transferred to individual accounts to be amortized on the books and records upon Commission approval.
93 Please see the 2011 Kansas Depreciation Study filed in this case for more details.

Source: See Relied Files 1a, 1b, 1c, 2a, Reclass of 376 and 367

Atmos Energy Corporation
Kansas Distribution Systems
Functional Plant in Service Acct 101 - Shared Services
Balance as of September 30, 2011

Line No.	Property Type	Description	Shared Srvc Div 02	Reclass Adjustment	Alloc factor	Adjusted Total
	(a)	(b)	(c)	(d)	(e)	(f)
	Shared Services Gross General Plant					
		General Plant				
1	39000	Structures & Improvements	$ -			$ -
2	39009	Improv. to Leased Premises	8,253,038			8,253,038
3	39100	Office Furniture & Equipment	11,475,202			11,475,202
4	39102	Remittance Processing Equipme	0			0
5	39103	Office Furn. Copiers & Type	0			0
6	39200	Transportation Equipment	96,290			96,290
7	39300	Stores Equipment	0			0
8	39400	Tools, Shop, & Garage Equip.	83,933			83,933
9	39700	Communication Equipment	2,355,236			2,355,236
10	39800	Miscellaneous Equipment	236,331			236,331
11	39900	Other Tangible Property	162,268			162,268
12	39901	Oth Tang Prop Servers H/W	24,760,357			24,760,357
13	39902	Oth Tang Prop Servers S/W	13,285,696			13,285,696
14	39903	Oth Tang Prop Network H/W	3,911,025			3,911,025
15	39904	Oth Tang Prop CPU	1,095,465			1,095,465
16	39905	Oth Tang Prop MF Hardware	1,159,964			1,159,964
17	39906	Oth Tang Prop PC Hardware [1]	4,704,521	$ (7,266)		4,697,255
18	39907	Oth Tang Prop PC Software	1,769,409			1,769,409
19	39908	Oth Tang Prop Appl Software	82,235,740			82,235,740
20	39909	Oth Tang Prop Mainframe S/W	2,614,619			2,614,619
21	39924	Oth Tang Prop Gen. Starup C	0			0
22						
23		Shared Service Gross Plant	$ 158,199,095	$ (7,266)	4.07%	$ 158,191,829
24						
25		SSU Gross Plant Allocated to KS Jurisdiction				$ 6,438,407
26						
27	General Plant					
28	Greenville Data Center					
29	39005	G-Structures & Improvements	$ 9,154,286			$ 9,154,286
30	39104	G-Office Furniture & Equip.	63,741			63,741
31						
32		Greenville Data Center Gross Plant	$ 9,218,027	$ -	1.58%	$ 9,218,027
33						
34						
35		GDC Allocated to KS Jurisdiction				$ 146,008
36						
37						
38		Total Amount Allocated to KS Jurisdiction				$ 6,584,416
39						
40	Note:					
41	[1] Reclassification of CSU office property incorrectly booked to SSU, see WP 5-5 for details					

Source: See Relied Files 1d, 2a
Section 12 Allocations, Relied 12a GDC allocations

Atmos Energy Corporation
Kansas Distribution Systems
Functional Plant in Service Acct 101 - Customer Support
Balance as of September 30, 2011

Line No.	Property Type	Description		Cust Support Div 12	Reclass Adjustment	Alloc factor	Adjusted Total
	(a)	(b)		(c)	(d)	(e)	(f)
	Customer Support Gross Plant						
		General Plant					
1	38900	Land		$ 2,874,240			$ 2,874,240
2	39000	Structures & Improvements		13,168,087			13,168,087
3	39009	Improv. to Leased Premises		4,437,465			4,437,465
4	39100	Office Furniture & Equipment		1,054,834			1,054,834
5	39700	Communication Equipment		26,143,741			26,143,741
6	39800	Miscellaneous Equipment		9,533			9,533
7	39900	Other Tangible Property		0			0
8	39901	Oth Tang Prop Servers H/W		13,047,889			13,047,889
9	39902	Oth Tang Prop Servers S/W		7,582,366			7,582,366
10	39903	Oth Tang Prop Network H/W		913,069			913,069
11	39906	Oth Tang Prop PC Hardware	[1]	2,549,162	$ 7,266		2,556,429
12	39907	Oth Tang Prop PC Software		3,327,195			3,327,195
13	39908	Oth Tang Prop Appl Software		93,618,084			93,618,084
14	39924	Oth Tang Prop Gen. Startup C		23,172,326			23,172,326
15		Customer Support Gross Plant		$ 191,897,992	$ 7,266		$ 191,905,258
16							
17		Amount Allocated to KS Jurisdiction				4.17%	$ 8,002,449
18							
19	General Plant						
20	Charles K. Vaughn Training Ctr						
21	38910	CKV-Land & Land Rights		$ 1,887,123			$ 1,887,123
22	39010	CKV-Structures & Improvements		10,400,518			10,400,518
23	39710	CKV-Communication Equipment		271,621			271,621
24	39910	CKV-Other Tangible Property		90,541			90,541
25	39916	CKV-Oth Tang Prop-PC Hardware		194,015			194,015
26	39917	CKV-Oth Tang Prop-PC Software		90,541			90,541
27		CKV - Gross Plant		$ 12,934,358	$ -		$ 12,934,358
28							
29		Amount Allocated to KS Jurisdiction				2.64%	$ 341,353
30							
31							
32		Total Amount Allocated to KS Jurisdiction					$ 8,343,802
33							
34	Note:						
35	[1] Reclassification of CSU office property incorrectly booked to SSU, see WP 5-5 for details						

Source: See Relied Files 1e, 2a
Section 12 Allocations

Atmos Energy Corporation
Kansas Distribution Systems
Functional Plant in Service Acct 101 - CO/KS General Office
Balance as of September 30, 2011

Line No.	Property Type	Description		CO/KS G.O. Div 30	Alloc factor
	(a)	(b)		(c)	(d)
	CO/KS General Office Gross Plant				
		General Plant			
1	39009	Improv. to Leased Premises	$	189,717	
2	39100	Office Furniture & Equipment		291,889	
3	39103	Office Furn. Copiers & Type		0	
4	39400	Tools, Shop, & Garage Equip.		255,608	
5	39700	Communication Equipment		225,803	
6	39800	Miscellaneous Equipment		228,979	
7	39901	Oth Tang Prop Servers H/W		331,037	
8	39902	Oth Tang Prop Servers S/W		0	
9	39903	Oth Tang Prop Network H/W		388,980	
10	39906	Oth Tang Prop PC Hardware		898,952	
11	39907	Oth Tang Prop PC Software		82,220	
12					
13		Total CO/KS G.O. Gross Plant	$	2,893,184	
14					
15		Total Allocated to KS Jurisdiction	$	1,684,990	58.24%

Source: See Relied Files 1f, 2a
Section 12 Allocations

Atmos Energy Corporation
Kansas Distribution Systems
Summary Plant in Service Acct 101
Balance as of September 30, 2011

Line No.	Description	Book Amounts	Adjustments	Adjusted Amounts	Alloc %	Kansas Juris
	(a)	(b)	(c)	(d)	(e)	(f)
	Direct					
1	Liberty Div 79	$ 5,926,374	$ -	$ 5,926,374		$ 5,926,374
2	Kansas Div 81	229,170,412	-	229,170,412		229,170,412
3	Southwest Div 86	16,790,784	-	16,790,784		16,790,784
4	Kansas Admin Div 80	-	-	-		0
5						
6	Allocated					
7	Shared Services Div 02	$ 158,199,095	$ (7,266)	$ 158,191,829	4.07%	$ 6,438,407
8	Greenville Data Center Div 02	9,218,027		9,218,027	1.58%	146,008
9	Customer Support Div 12	191,897,992	7,266	191,905,258	4.17%	8,002,449
10	Charles K Vaughn Training Ctr Div 12	12,934,358		12,934,358	2.64%	341,353
11	CO/KS General Office Div 30	2,893,184	-	2,893,184	58.24%	1,684,990
12						
13	Total	$ 627,030,226	$ -	$ 627,030,226		$ 268,500,779

Source: See Relied Files 1a-1f
Section 12 Allocations

Kansas Distribution System
Plant in Service
Twelve Months Ended September 30, 2011
Kansas

Line No.	Description	Property Type	Source: KS Annual Filing Balance at 12/31/08	Balance at 12/31/09	Balance at 12/31/10	Balance at 9/30/10	Balance at 9/30/11
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Intangible Plant:**						
2	Organization	30100	$ -	$ -	$ -	$ -	$ -
3	Franchises & Consents	30200	37,160	37,160	37,160	37,160	37,160
4	Other Misc. Intangibles	30300	3,918	3,918	3,918	3,918	3,918
5	Total Intangible Plant		$ 41,078	$ 41,078	$ 41,078	$ 41,078	$ 41,078
6							
7	**Production and Gathering Plant:**						
8	Rights of Way	32540	$ -	$ -	$ -	$ -	$ -
9	Field Meas. & Reg. Structures	32800	0	0	0	0	0
10	Field Lines	33200	0	0	0	0	0
11	Field Meas. & Reg. Sta. Equip.	33400	0	0	0	0	0
12	Total Storage Plant		$ -	$ -	$ -	$ -	$ -
13							
14	**Underground Storage Plant:**						
15	Land	35010	$ 49,164	$ 49,164	$ 49,164	$ 49,164	$ 49,164
16	Leaseholds	35020	568,935	568,935	568,935	568,935	568,935
17	Structures & Improvements	35100	102,923	102,923	102,923	102,923	102,923
18	Wells	35200	1,166,836	1,166,836	1,166,836	1,130,321	1,136,225
19		35202	0	0	0	36,515	36,515
20	Lines	35300	1,090,230	1,090,230	1,090,230	1,090,230	1,090,230
21	Compressor station equipment	35400	2,259,430	2,259,430	2,259,430	2,259,430	2,259,430
22	Measuring and Reg. Equipment	35500	203,329	203,329	220,011	220,011	220,011
23	Purification Equipment	35600	288,382	288,382	288,382	288,382	288,382
24	Other equipment	35700	125,321	125,321	125,321	125,321	167,513
25	Total Underground Storage Plant:		$ 5,854,550	$ 5,854,550	$ 5,871,232	$ 5,871,232	$ 5,919,327
26							
27	**Transmission Plant:**						
28	Land & Land Rights	36500	$ 16,369	$ 16,369	$ 11,252	$ 11,252	$ 11,252
29	Rights of Way	36520	7,169	7,169	9,037	9,037	9,037
30	Structures & Improvements	36600	33,191	33,191	33,191	33,191	33,191
31	Mains - Cathodic Protection	36700	3,477,804	3,477,804	3,477,804	3,477,804	3,622,307
32	Compressor station equipment	36800	31,497	31,497	31,497	31,496	31,496
33	Meas. & Reg. Sta. Equipment	36900	487,829	519,110	526,227	526,227	526,227
34	Communication equipment	37000	0	0	0	0	0
35	Other equipment	37100	0	0	0	0	0
36	Total Transmission Plant		$ 4,053,859	$ 4,085,140	$ 4,089,008	$ 4,089,008	$ 4,233,511
37							
38	**Distribution Plant:**						
39	Land Rights	37400	$ 945,352	$ 953,350	$ 963,579	$ 962,821	$ 963,586
40	Structures & Improvements	37500	119,494	119,494	119,494	119,494	119,494
41	Mains-Cathodic Protection	37600	110,855,692	115,753,509	120,562,537	119,747,648	125,538,982
42	Meas. & Reg. Sta. Equipment - General	37800	2,857,922	2,967,805	3,171,679	3,207,156	3,531,317
43	Meas. & Reg. Sta. Equipment - City Gate	37900	2,131,872	2,155,775	2,162,730	2,162,730	2,213,402
44	Services	38000	52,629,237	54,573,626	56,879,925	56,277,545	57,635,135
45	Meters	38100	12,850,744	14,059,318	14,423,068	14,294,670	15,021,142
46	Meter Installations	38200	20,323,050	21,981,080	23,458,818	23,017,182	23,917,803
47	Regulators	38300	2,130,411	2,160,201	2,184,373	2,174,771	2,209,798
48	House Reg. Installations	38400	209,461	209,461	209,461	209,461	209,461
49	Ind. Meas. & Reg. Sta. Equipment	38500	641,369	660,838	763,464	756,526	935,854
50	Other Equipment	38700	13,769	13,769	13,769	13,769	18,236
51	Total Distribution Plant		$ 205,708,373	$ 215,608,226	$ 224,912,897	$ 222,943,773	$ 232,314,212
52	Distribution Plant Allocated from Meter Shop						
53	Total Direct and Allocated Distribution Plant		$ 205,708,373	$ 215,608,226	$ 224,912,897	$ 222,943,773	$ 232,314,212
54							

Kansas Distribution System
Plant in Service
Twelve Months Ended September 30, 2011
Kansas

Line No.	Description	Property Type	Balance at 12/31/08 (Source: KS Annual Filing)	Balance at 12/31/09 (Source: KS Annual Filing)	Balance at 12/31/10 (Source: KS Annual Filing)	Balance at 9/30/10	Balance at 9/30/11
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
55							
56	**General Plant:**						
57	Land & Land Rights	38900	$ 52,333	$ 52,333	$ 187,466	$ 182,971	$ 152,535
58	Structures & Improvements	39000	1,103,253	1,436,744	1,657,509	1,648,296	1,902,976
59	Office Furniture & Equipment	39100	303,206	343,400	417,385	417,386	416,854
60	Transportation Equipment	39200	92,776	73,888	274,573	274,573	274,502
61	Stores Equipment	39300	4,393	4,393	1,308	1,308	1,308
62	Tools & Work Equipment	39400	1,623,809	1,672,265	1,926,920	1,763,132	2,091,865
63	Laboratory Equipment	39500	11,655	10,089	8,289	8,289	8,289
64	Power Operated Equipment	39600	606,233	587,219	754,003	749,613	793,008
65	Comm. Equip. - Telephones	39700	154,895	272,986	288,179	288,224	405,255
66	Miscellaneous Equipment	39800	1,203,713	1,311,357	1,553,879	1,507,001	1,606,195
67	Other Tangible Property	39900	1,356,481	1,249,635	1,517,819	1,412,560	1,726,654
68	Direct General Plant		$ 6,512,747	$ 7,014,309	$ 8,587,330	$ 8,253,353	$ 9,379,442
69							
70	Total Plant in Service		$ 222,170,607	$ 232,603,303	$ 243,501,545	$ 241,198,443	$ 251,887,570

Source: See Relied Files 4a, 4b, 4c Pg 6 - 9
Relied 2b
Section 4

Atmos Energy Corporation
Kansas Distribution Systems
Accumulated Depreciation Acct 108 - Kansas Direct and Allocated
Balance as of September 30, 2011

Line No.	Description	Property Type	Liberty Div 79	Kansas Div 81	Southwest Div Div 86	Asset Transfers	Total Kansas
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Kansas Direct Accumulated Depreciation by Functional Plant Account					
	Intangible Plant A/D						
1	Organization	30100	$ -	$ (25,000)	$ -	$ -	$ (25,000)
2	Franch & Consent Grp	30200		15,036			15,036
3	Intangibles Grp	30300		(10,081)			(10,081)
4	Total Intangible Plant		$ -	$ (20,045)	$ -	$ -	$ (20,045)
5							
6	**Production and Gathering Plant A/D**		$ -	$ -	$ -	$ -	$ -
7	Rights-of-way	32540					0
8	Field Measuring And R	32800					0
9	Field Lines	33200					0
10	Field Compressor Stat	33300					0
11	Field Measuring And R	33400					0
12	Total Prod & Gathering Plant		$ -	$ -	$ -	$ -	$ -
13							
14	**Underground Storage A/D**						
15	Rights-of-way	35020	$ 57,842	$ -	$ -	$ -	$ 57,842
16	Structures And Improv	35100	30,470				30,470
17	Meas & Reg Structures	35130	6,363				6,363
18	Other Structures	35140	20,851				20,851
19	Wells	35200	723,964				723,964
20	Leaseholds & Rights	35210	(12,263)				(12,263)
21	Reservoirs	35220	21,521				21,521
22	Pipeline	35300	614,570			2,553	617,123
23	Compressor Equip	35400	1,964,165				1,964,165
24	Meas & Reg Equip	35500	131,709				131,709
25	Purification Equip	35600	176,260				176,260
26	Other Equip	35700	74,425			(1,598)	72,827
27	Total Underground Storage Plant		$ 3,809,876	$ -	$ -	$ 955	$ 3,810,831
28							
29	**Transmission Plant A/D**						
30	Land	36500	$ -	$ -	$ (16,538)	$ -	$ (16,538)
31	Structures And Improv	36600			24,337		24,337
32	Mains - Cathodic Prot	36700		719,643	1,346,040		2,065,683
33	Mains-Steel	36710		1,148	417		1,564
34	Compressor Station Eq	36800			1,854		1,854
35	Measuring And Reg	36900		18,066	335,373		353,440
36	Other Equipment Stora	37100			(9,910)		(9,910)
37	Total Transmission Plant		$ -	$ 738,857	$ 1,681,573	$ -	$ 2,420,430
38							
39	**Distribution Plant A/D**						
40	Land & Land Rights	37400	$ -	$ 174,934	$ 19,187	$ -	$ 194,121
41	Rights-of-way	37420		27,788	(105,049)		(77,261)
42	Structures & Improvem	37500		54,394	(1,704)		52,690
43	Mains	37600		44,097,123	780,632		44,877,755
44	Compressor Station Equip	37700			0		0
45	Meas	37800		1,703,494	8,256	4,697	1,716,447
46	Meas & Reg Station Eq	37900		1,202,811	219	196	1,203,226
47	Meas	37980			5,163		5,163
48	Services	38000		20,074,078	1,851,127		21,925,205
49	Meters	38100		7,230,388	372,156		7,602,543
50	Meter Installations	38200		2,090,449	568,024		2,658,473
51	House Regulators	38300		1,280,199	48,828		1,329,026
52	House Regulator Insta	38400		200,420	(14,472)		185,948
53	Industrial Measuring	38500		232,432	42,956	9,019	284,406
54	Other Equipment Distr	38700		1,840	837	341,081	343,758
55	Total Distribution Plant		$ -	$ 78,370,348	$ 3,576,159	$ 354,993	$ 82,301,500

Atmos Energy Corporation
Kansas Distribution Systems
Accumulated Depreciation Acct 108 - Kansas Direct and Allocated
Balance as of September 30, 2011

Line No.	Description	Property Type	Liberty Div 79	Kansas Div 81	Southwest Div Div 86	Asset Transfers	Total Kansas
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Kansas Direct Accumulated Depreciation by Functional Plant Account					
56							
57	**Direct General Plant A/D**						
58	Land & Land Rights	38900	$ -	$ (2,883)	$ -	$ -	$ (2,883)
59	Struct & Improve Grp	39000		270,043	10,255		280,298
60	Improvements Grp	39030		730			730
61	Air Condition Eq Grp	39040			5,242		5,242
62	Improve - Leased Grp	39090		18,723	(4,219)		14,504
63	Office Furniture And	39100		(212,786)	(66,582)	393	(278,975)
64	Office Machines	39130		(11,143)	(12,209)		(23,352)
65	Transp Equip - Group	39200		252,210	(12,158)	93,978	334,031
66	Stores Equipment	39300		(6,352)	0		(6,352)
67	Tools & Shop Equip	39400	3,261	638,163	64,133	196,874	902,431
68	Laboratory Equipment	39500		587	3,056	3,381	7,024
69	Power Op Equip-Group	39600		247,140	6,084	5,582	258,805
70	Ditchers	39630		71,728	29,589		101,316
71	Backhoes	39640		104,497	(8,906)		95,591
72	Welders	39650		21,495			21,495
73	Communication Equipme	39700		18,299	9,944	119	28,363
74	Communication Equip	39710		(33,231)	(2,688)	4,691	(31,228)
75	Communication Equip	39720		(6,323)		794	(5,528)
76	Miscellaneous Equipme	39800		634,185	38	(642,222)	(7,999)
77	Other Tangible Equipm	39900		19,376		(19,539)	(163)
78	Servers Hardware	39910		2,716			2,716
79	Servers Software	39920		15,363			15,363
80	Network Hardware	39930		32,742			32,742
81	Mainframe Hardware	39950		1,231			1,231
82	Pc Hardware	39960		560,869	15,269		576,138
83	Oth Tang Prop - PC So	39970		10,757			10,757
84	Application Software	39980		48,898			48,898
85	Total Direct General Plant		$ 3,261	$ 2,697,034	$ 36,849	$ (355,948)	$ 2,381,196
86	Retirement Work In Progress	RWIP	0	(1,341,518)	(289,406)		(1,630,924)
87							
88	Reconciling Items		0	3	0		3
89	**Total Kansas Direct Accum. Deprec.**		$ 3,813,137	$ 80,444,679	$ 5,005,175	$ -	$ 89,262,990
90							
91	General Accum Deprec Alloc from Shared Services	WP 5-2					$ 3,706,732
92	General Accum Deprec Alloc from Customer Support	WP 5-3					6,087,258
93	General Accum Deprec Alloc from CO/KS Gen Office	WP 5-4					770,252
94							
95	**Total KS Direct and Allocated Accum. Deprec.**						$ 99,827,232
96							
97	**Source: See Relied Files 1a, 1b, 1c, 2c**						

Atmos Energy Corporation
Kansas Distribution Systems
Accumulated Depreciation Acct 108 - Shared Services - Division 002
Balance as of September 30, 2011

Line No.	Description	Property Type	Shared Srvc Div 02	Reclass Adjustment	Alloc factor	Adjusted Total
	(a)	(b)	(c)	(d)	(e)	(f)
		Shared Services Accum Deprec by Functional Plant Acct				
	General Plant A/D					
1	Structure & Improv	39000	$ -			$ -
2	Improvements - Leased	39009	8,091,940			8,091,940
3	Office Furniture And	39100	7,371,465			7,371,465
4	Remittance Processing	39102	5,860			5,860
5	Office Machines	39103	2,888			2,888
6	Transportation Equipm	39200	18,000			18,000
7	Stores Equipment	39300	758			758
8	Tools Shop And Garage	39400	15,187			15,187
9	Laboratory Equipment	39500	0			0
10	Communication Equipme	39700	815,723			815,723
11	Miscellaneous Equipme	39800	79,943			79,943
12	Inserter	39809	0			0
13	Other Tangible Equipm	39900	45,878			45,878
14	Servers-Hardware	39901	8,340,234			8,340,234
15	Servers-Software	39902	4,223,186			4,223,186
16	Network Hardware	39903	1,762,796			1,762,796
17	Mainframe Cpu	39904	1,111,824			1,111,824
18	Mainframe Hardware	39905	1,174,870			1,174,870
19	Pc Hardware [1]	39906	4,442,359	$ (849)		4,441,510
20	Pc Software	39907	1,671,823			1,671,823
21	Application Software	39908	48,758,042			48,758,042
22	Mainframe Software	39909	2,722,303			2,722,303
23	Oth Tang Prop - Gen	39924	0			0
24	SSU Accum Deprec		$ 90,655,079	$ (849)		$ 90,654,230
25	Retirement Work in Progress		(153)			(153)
26	Total SSU Accum Deprec		$ 90,654,926	$ (849)		$ 90,654,077
27						
28	Amount Allocated to KS Jurisdiction				4.07%	$ 3,689,621
29	General Plant					
30	Greenville Data Center					
31	Structure & Improv	39005	$ 1,076,794			$ 1,076,794
32	Office Furniture And	39104	3,482			3,482
33	Total Greenville Data Center		$ 1,080,276	$ -		$ 1,080,276
34						
35	Amount Allocated to KS Jurisdiction				1.58%	$ 17,111
36						
37	**Total Amount Allocated to KS Jurisdiction**					**$ 3,706,732**
38						
39	Total General Plant Accum. Deprec.		$ 91,735,355			
40	Retirement Work in Progress		(153)			
41	Total SSU Accum Deprec		$ 91,735,202			
42						
43						
44	Note:					
45	[1] Reclassification of CSU office property incorrectly booked to SSU, see WP 5-5 for details					

Source: See Relied Files 1d, 2c (Provided in Response to DR 1)
Section 12 Allocations

Atmos Energy Corporation
Kansas Distribution Systems
Accumulated Depreciation Acct 108 - Shared Services - Division 012
Balance as of September 30, 2011

Line No.	Description	Property Type	Cust Support Div 12	Reclass Adjustment	Alloc factor	Adjusted Total
	(a)	(b)	(c)	(d)	(e)	(f)
		Customer Support Accum Deprec by Functional Plant Acct				
	General Plant A/D					
1	Structure & Improv	39000	$ 589,389			$ 589,389
2	Improvements - Leased	39009	2,836,296			2,836,296
3	Office Furniture And	39100	65,361			65,361
4	Office Furniture And	39101	0			0
5	Remittance Processing	39102	0			0
6	Office Machines	39103	0			0
7	Communication Equipme	39700	16,607,891			16,607,891
8	Miscellaneous Equipme	39800	1,306			1,306
9	Other Tangible Equipm	39900	(1,031)			(1,031)
10	Servers-Hardware	39901	12,142,549			12,142,549
11	Servers-Software	39902	7,492,590			7,492,590
12	Network Hardware	39903	504,991			504,991
13	Pc Hardware [1]	39906	1,911,712	$ 849		1,912,561
14	Pc Software	39907	2,975,412			2,975,412
15	Application Software	39908	77,070,004			77,070,004
16	Oth Tang Prop - Gen	39924	23,168,336			23,168,336
17	Total General Plant Accum. Deprec.		$ 145,364,806	$ 849		$ 145,365,655
18	Retirement Work in Progress		(865)			(865)
19	Customer Support Accum. Deprec.		$ 145,363,941	$ 849		$ 145,364,790
20						
21	Amount Allocated to KS Jurisdiction				4.17%	$ 6,061,712
22						
23	General Plant					
24	Charles K. Vaughn Training Ctr					
25	CKV-Struct & Improv	39010	$ 895,200			$ 895,200
26	CKV-Commun Equip	39710	23,806			23,806
27	CKV-Other Tang Equip	39910	6,861			6,861
28	CKV-Pc Hardware	39916	33,508			33,508
29	CKV-Pc Software	39917	8,599			8,599
30			$ 967,974	$ -		$ 967,974
31						
32	Amount Allocated to KS Jurisdiction				2.64%	$ 25,546
33						
34	**Total Amount Allocated to KS Jurisdiction**					**$ 6,087,258**
35						
36	Total General Plant Accum. Deprec.		$ 146,331,915			
37	Retirement Work in Progress		(865)			
38	Total SSU Accum Deprec		$ 146,331,050			
39						
40	Note:					
41	[1] Reclassification of CSU office property incorrectly booked to SSU, see WP 5-5 for details					

Source: See Relied Files 1e, 2c (Provided in response to DR 1)
Section 12 Allocations

Atmos Energy Corporation
Kansas Distribution Systems
Accumulated Depreciation Acct 108 - CO/KS General Office - Division 030
Balance as of September 30, 2011

Line No.	Description	Property Type	CO/KS G.O. Div 30	Alloc factor
	(a)	(b)	(c)	(d)
		CO/KS General Office Accumulated Depreciation by Functional Plant Acct		
	General Plant			
1	Improv. Lease Premis	39009	$ 55,680	
2	Office Furniture And	39100	48,429	
3	Office Machines	39103	0	
4	Transp Equip-Grp	39200	0	
5	Tools Shop And Garage	39400	161,383	
6	Communication Equipme	39700	49,477	
7	Miscellaneous Equipme	39800	34,468	
8	Servers Hardware	39901	142,806	
9	Servers Software	39902	0	
10	Network Hardware	39903	175,287	
11	Oth Tang Prop - Mainf	39905	0	
12	Pc Hardware	39906	545,974	
13	Pc Software	39907	26,191	
14	Total General Plant Accum. Deprec.		$ 1,239,695	
15	Retirement Work in Progress		82,853	
16	Total Customer Support Accum. Deprec.		$ 1,322,548	
17				
18	Total Allocated to KS Jurisdiction		$ 770,252	58.24%

Source: See Relied Files 1f, 2c (Provided in response to DR 1)
Section 12 Allocations

Atmos Energy Corp.
Calendar 2011 Activity
SSU General Office Projects Reclassed to Customer Support

WP 5-5

Calendar 2011

Sum of PP							month_number	Accum. Depr (1)
company	ferc_activi	business_segment	budget category	act_work_o	work_order_long_desc	utility_account	201110	
010 Atmos Regulated Sh	Transfer	002 - Dallas Atmos Rate Division	Information Techn	010.11671	Desktops for Billing New Hires	39906-Oth Tang Prop - PC H	(1,388.47)	(162.23)
					Desktops for Billing New Hires Total		(1,388.47)	
				010.11705	4 Desktops for new dispatchers	39906-Oth Tang Prop - PC H	(5,877.98)	(686.79)
					4 Desktops for new dispatchers Total		(5,877.98)	
			Information Technology Total				(7,266.45)	
		002 - Dallas Atmos Rate Division Total					(7,266.45)	
		012 - Call Center Division	Information Techn	010.11671	Desktops for Billing	39906-Oth Tang Prop - PC H	1,388.47	162.23
					Desktops for Billing New Hires Total		1,388.47	
				010.11705	4 Desktops for new	39906-Oth Tang Prop - PC H	5,877.98	686.79
					4 Desktops for new dispatchers Total		5,877.98	
			Information				7,266.45	
		012 - Call Center Division Total					7,266.45	
	Transfer Total						-	
010 Atmos Regulated Shared Services Total							-	
Grand Total							-	

(1) - Accumulated Depreciation confirmed in relied file labeled, "SSU Project Correction for Upcoming Rate Filings.msg"

Atmos Energy Corporation
Kansas Distribution System
Summary of Working Capital
Test period ended September 30, 2011

Line No.	Description	Source	Total Kansas Juris. Direct & Alloc Amount	Total Kansas Juris. Adjusted Amount
	(a)	(b)	(c)	(d)
1	Prepayments [1]	WP 6-1	$ 651,845	$ 651,845
2	Storage Gas [1]	WP 6-2	11,175,793	11,175,793
3	Cash Requirements		0	0
4				
5	Total		$ 11,827,637	$ 11,827,637
6				
7	Note:			
8	[1] 13 month average.			

Atmos Energy Corporation
Kansas Distribution System
Jurisdictional Prepayments Acct 165
Thirteen Month Average Balance Ended September 30, 2011

Line No.	Description	Reference	Avg Amount	Allocation
	(a)	(b)	(c)	(d)
1	Shared Services Div 02	WP 6-1-1	$ 12,414,950	$ 505,288
2	SS Cust Support Div 12	WP 6-1-1	1,935,000	80,689
3	CoKs Gen Office Div 30	WP 6-1-1	113,096	65,867
4				
5				
6				$ 651,845

Source: Section 12 Allocations

Kansas Distribution System
Prepayments 165
Thirteen Month Average Balance Ended September 30, 2011

Line No.	Sub Acct. No.	Description	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	13 Month Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1		**Division 02 Shared Service**														
2	13000	Prepaid Expenses Misc	$ 165,154	$ -	$ 123,143	$ 123,143	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,649
3	13001	Prepaid-Worker's Comp Ins	-	-	6,068	113,311	112,729	112,729	-	6,807	-	-	-	-	-	27,049
4	13003	Prepaid-Auto Liability Ins	203,601	169,668	135,734	101,801	67,867	33,934	-	32,562	32,542	32,522	32,502	32,482	32,462	69,821
5	13004	Prepaid-Liability Insurance-Other	2,308	769	12,081	10,873	9,665	8,457	7,249	6,041	4,832	3,624	2,416	1,208	-	5,348
6	13005	Prepaid-Insurance-D&O	1,361,126	1,209,890	1,058,653	907,417	756,181	604,945	453,709	302,472	151,236	-	1,489,120	1,353,745	1,218,371	835,913
7	13006	Prepaid-Aegis General Liability	7,055,447	7,706,811	7,946,275	7,161,991	6,363,894	5,572,704	4,781,513	3,990,323	3,271,919	2,480,729	1,689,538	898,348	1,091,284	4,616,213
8	13010	Prepaid-Symantec Software	48,209	44,192	40,174	36,157	32,139	28,122	24,105	20,087	16,070	12,052	8,035	123,512	129,353	43,247
9	13012	Prepaid-COLI Ins Premium	340,499	474,453	425,626	376,798	327,970	279,143	418,934	369,765	232,723	358,345	309,176	303,845	254,676	343,996
10	13013	Prepaid-SS Mailroom Postage Machine	18,742	32,590	46,230	33,905	41,261	30,681	18,402	783	14,595	2,269	2,269	(12,869)	6,207	18,082
11	13015	Prepaid-Postage for Cust Billing	705,916	231,942	503,202	448,382	537,618	571,019	486,686	269,024	569,278	549,647	287,656	583,972	959,802	515,703
12	13027	Prepaid-Southern Gas Dues	34,500	31,625	28,750	37,075	23,000	20,125	17,250	14,375	11,500	8,625	5,750	2,875	-	18,112
13	13028	Prepaid-American Gas Dues	153,011	102,007	706,929	655,925	601,265	546,604	491,944	437,283	382,623	327,962	273,302	218,642	163,981	389,344
14	13035	Prepaid-NationsBank Of Tx $600M note	112,660	401,149	97,639	90,128	82,617	75,107	67,596	60,085	2,863,958	2,815,417	2,766,875	2,718,333	2,669,792	1,140,104
15	13040	Prepaid-Misc 1	-	-	-	-	-	-	-	-	-	81,188	54,125	27,063	316,815	36,861
16	13046	Maintenance contract for TMAN	3,921	1,961	-	22,646	20,587	18,528	16,470	14,411	12,352	10,294	8,235	6,176	4,117	10,746
17	13047	Prepaid-Bill Printing Supplies	(16,056)	(173,751)	(319,726)	(491,104)	(673,845)	(832,566)	(1,018,682)	(1,175,442)	(1,360,198)	(1,524,272)	(1,685,870)	(1,836,157)	(2,003,253)	(1,008,532)
18	13063	Prepaid-CFC - Oracle	46,736	41,543	36,350	31,157	25,964	20,772	15,579	10,386	5,193	-	-	-	-	17,975
19	13064	Ppd-Markview Maint	49,325	44,841	40,357	35,873	31,389	62,908	55,151	47,394	39,637	31,879	24,122	16,365	13,092	37,872
20	13067	Blueflame Property Insurance	1,528,023	1,018,671	509,319	(33)	(509,385)	(1,039,059)	4,675,580	4,156,067	3,636,554	3,117,041	2,597,528	2,078,015	1,558,502	1,794,371
21	13068	Ppd Advantex Maint	37,739	465,459	465,459	465,459	-	-	-	-	-	-	-	-	469,415	146,425
22	13069	Deloitte & Touche Tech prepaid	47,850	43,534	43,165	38,848	34,532	30,215	25,899	21,582	17,266	12,949	8,633	59,284	59,503	34,097
23	13075	Prepaid-Sunguard SW Maint (TBS)	-	-	-	-	-	-	-	-	306,296	275,667	245,037	214,407	183,778	94,245
24	13076	Prepaid-Powerplant	-	122,092	110,992	99,893	88,794	77,695	66,595	55,496	44,397	33,298	22,199	11,099	-	56,350
25	13077	Ppd-GE Smallworld maint	122,889	81,926	40,963	433,779	397,631	361,483	325,334	289,186	253,038	216,890	180,741	144,593	108,445	227,454
26	13083	Prepaid-RedHat Software	23,312	11,656	-	-	-	114,433	100,128	85,824	71,520	57,216	42,912	28,608	14,304	42,301
27	13086	Prepaid-MapFrame	99,264	76,019	52,774	39,581	107,575	13,194	-	211,012	180,867	150,723	120,578	90,434	60,289	92,485
28	13092	Prepaid Antispam Software Maint	24,839	21,734	18,629	15,524	12,419	9,314	6,210	3,105	-	126,266	122,658	119,051	115,443	45,784
29	13093	Prepaid Scanmail Software Maint	15,093	13,207	11,320	9,433	7,547	5,660	3,773	1,887	-	86,618	89,242	86,618	83,993	31,876
30	13094	Prepaid-NationsBank Of Tx $300M note	77,109	(24,688)	246,625	172,563	147,875	73,813	24,438	(250)	-	-	-	-	-	55,191
31	13096	Prepaid-CFC - AT&T	62,489	59,017	55,545	52,074	48,602	45,131	41,659	38,188	34,716	31,244	27,773	24,301	20,830	41,659
32	13097	Prepaid-Oracle Infrastructure	1,492,950	1,306,331	1,119,712	933,094	746,475	559,856	373,237	2,317,434	2,306,608	2,114,390	1,903,511	1,713,160	1,522,809	1,416,121
33	13098	Prepaid-Oracle Hyperion	170,579	156,364	142,149	127,934	113,719	99,504	85,289	71,075	56,860	42,645	28,430	14,215	116,008	94,213
34	13099	Prepaid-Oracle Applications	512,315	448,276	384,236	320,197	256,157	192,118	128,079	64,039	791,527	725,566	659,606	593,645	527,684	431,034
35	13100	Prepaid-Alfresco	47,928	45,844	43,760	41,676	39,592	37,509	35,425	33,341	31,257	29,173	27,090	25,006	22,922	35,425
36	13102	Prepaid-Google	113,663	109,453	105,243	101,033	96,824	92,614	88,404	84,194	79,985	75,775	71,565	67,356	63,146	88,404
37	13103	Prepaid-NEC Unified Solutions	146,541	133,397	120,253	107,108	93,964	80,820	67,676	64,600	183,751	168,452	153,153	137,854	122,555	121,548
38	13104	Prepaid-Citrix NetScaler Maint	43,419	40,524	37,629	34,735	31,840	28,946	26,051	23,157	20,262	17,367	14,473	11,578	113,783	34,136
39	13105	Prepaid-Oracle Golden	12,124	10,609	9,093	7,578	6,062	4,547	3,031	1,516	-	24,334	39,756	36,000	49,972	15,740
40	13107	Prepaid-MTM Technologi	-	-	-	-	(6,099)	134,174	128,075	121,976	115,877	109,779	103,680	97,581	91,482	68,963
41	13108	Prepaid-UC4 Software	-	-	-	-	(13,531)	60,891	54,125	47,359	40,594	33,828	27,062	20,297	13,531	21,858
42	13109	Prepaid-SumTotal	-	-	-	-	77,760	113,910	110,678	107,446	104,214	100,982	97,750	94,518	91,102	69,105
43	13111	Prepaid-Altiris	-	-	-	-	-	-	-	117,069	117,069	117,069	117,069	117,069	117,069	54,032
44	13113	Prepaid-Dell Service N	-	-	-	-	-	-	-	-	109,847	130,208	118,726	106,877	95,029	43,130
45	13114	Prepaid-Cvelo	-	-	-	-	-	-	-	-	-	-	255,667	506,465	506,465	97,584
46	13115	Prepaid-Enterprise Vault	-	-	-	-	-	-	-	-	-	-	-	-	104,762	8,059
47	13116	Prepaid-Austin Tetra	-	-	-	-	-	-	-	-	-	-	-	-	50,117	3,855
48		**DIV 02 Subtotal**	$ 14,863,224	$ 14,459,113	$ 14,404,353	$ 12,695,953	$ 10,138,655	$ 8,249,976	$ 12,205,592	$ 12,321,659	$ 14,750,764	$ 12,987,761	$ 12,342,091	$ 10,835,572	$ 11,139,636	$ 12,414,950

Kansas Distribution System
Prepayments 165
Thirteen Month Average Balance Ended September 30, 2011

Line No.	Sub Acct. No.	Description	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	13 Month Average
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
49																
50	**Division 12 Customer Support**															
51	13015	Prepaid-Worker's Comp Ins	$ 275,000	$ 275,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,308
52	13047	Prepaid - Verint System	49,486	240,987	421,677	555,152	745,596	906,934	1,054,414	1,205,779	1,352,230	1,469,402	1,671,995	1,801,876	1,974,662	1,034,630
53	13057	Prepaid - NICE System	303,566	293,774	283,981	274,189	264,396	254,604	244,812	235,019	225,227	215,434	205,642	195,849	186,057	244,812
54	13059	Prepaid - Virtual Hold	-	-	-	57,845	38,563	19,282	-	-	-	57,845	-	-	31,733	15,790
55	13068	Prepaid - Intervoice	-	-	(38,788)	(77,576)	349,094	310,306	271,518	232,729	193,941	155,153	116,365	77,577	38,788	125,316
56	13084	Prepaid - Virtual Hold Tech	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	13091	Prepaid-Sunguard SW Maint (TBS)	333,805	281,406	229,006	418,106	385,630	333,230	367,430	315,030	262,630	478,980	447,906	394,661	341,415	353,018
58	13095	Prepaid-A2D	17,555	8,777	-	69,762	62,010	230,473	116,693	100,169	83,644	67,120	50,595	34,071	17,546	66,032
59	13101	Prepaid Digital Data Voice	152,080	126,734	101,387	76,040	50,693	25,347	-	-	-	-	-	-	-	40,945
60	13110	Prepaid-Avaya	-	-	-	-	-	-	45,129	37,608	30,086	22,565	15,043	7,521	-	12,150
61		**DIV 12 Subtotal**	$ 1,131,493	$ 1,226,677	$ 997,263	$ 1,373,517	$ 1,895,983	$ 2,080,175	$ 2,099,996	$ 2,126,334	$ 2,147,759	$ 2,466,498	$ 2,507,546	$ 2,511,555	$ 2,590,201	$ 1,935,000
62																
63	**Division 30 CoKs General Office**															
64	13012	Prepaid-COLI Ins Premium	$ 12,767	$ 6,383	$ 76,603	$ 70,220	$ 63,836	$ 57,452	$ 51,069	$ 44,685	$ 38,302	$ 31,918	$ 25,534	$ 19,151	$ 12,767	$ 39,284
65	13022	Pd Rent-Gilliland COKS	73,812	73,812	73,812	73,812	73,812	73,812	73,812	73,812	73,812	73,812	73,812	73,812	73,812	73,812
66		**DIV 30 Subtotal**	$ 86,579	$ 80,195	$ 150,415	$ 144,032	$ 137,648	$ 131,264	$ 124,881	$ 118,497	$ 112,114	$ 105,730	$ 99,346	$ 92,963	$ 86,579	$ 113,096

Atmos Energy Corporation
Kansas Distribution System
Underground Storage Gas 164.1
Thirteen Month Average Balance Ended September 30, 2011

Line No.	Month/Year	Liberty DIV 79	KS Admin DIV 80	Kansas Div DIV 81	Kansas Total
	(a)	(b)	(c)	(d)	(e)
1	Sep-10	$ 8,077,058	$ 65,610	$ 7,904,302	$ 16,046,969
2	Oct-10	8,976,608	81,561	8,588,027	17,646,197
3	Nov-10	9,299,718	85,915	9,396,396	18,782,029
4	Dec-10	7,949,640	69,031	8,312,007	16,330,677
5	Jan-11	5,925,154	45,274	6,218,547	12,188,975
6	Feb-11	3,740,312	16,933	3,454,636	7,211,881
7	Mar-11	1,755,270	(6,668)	2,347,847	4,096,448
8	Apr-11	575,335	(20,688)	186,693	741,339
9	May-11	1,867,335	(28,407)	1,246,012	3,084,940
10	Jun-11	3,791,435	21,179	2,526,843	6,339,457
11	Jul-11	5,823,691	37,546	4,413,518	10,274,755
12	Aug-11	7,850,880	61,118	6,566,166	14,478,163
13	Sep-11	9,605,492	78,118	8,379,864	18,063,474
14					
15	13 Month Average	$ 5,787,533	$ 38,963	$ 5,349,297	$ 11,175,793

Source: See Relied File 1k - Storage Gas
Note: Storage Gas booked to Div 80 is attributed to Kansas Div 81.

Atmos Energy Corp. - Consolidated
Capital and Cost of Money
Test period ended September 30, 2011

Line No.	Description	Reference	Beginning Bal. 9/30/2010	Ending Bal. 9/30/2011	13 Month Average FY11	Rate Base Allocation
	(a)	(b)	(c)	(d)	(e)	(f)
1	LTD Capital		$ 2,169,682,149	$ 2,208,551,192	$ 2,150,136,447	$ 77,377,526
2	Equity Capital		2,178,347,890	2,255,421,743	2,297,954,916	82,697,108
3						
4	Total Capital		$ 4,348,030,039	$ 4,463,972,935	$ 4,448,091,363	$ 160,074,634
5						
6	LTD Capital %		49.90%	49.48%	48.34%	
7	Equity Capital %		50.10%	50.52%	51.66%	
8						
9	Total Capital %		100.00%	100.00%	100.00%	
10						
11	Long-term Debt Rate	WP 7A - Test Period			6.52%	
12	Cost of Equity				10.90%	
13						
14	Weighted Cost of Capital - LTD				3.15%	
15	Weighted Cost of Capital - Equity				5.63%	
16						
17	Total Cost of Capital				8.78%	ROR

Source: See Relied File 3a, 3b

Atmos Energy Corporation

Consolidated & Utility Long-Term Debt Outstanding w/ calculation of Effective Interest Rates
as of September 30, 2011

Line	Atmos Energy Corp., Consolidated: Debt Series (a)	Issued (b)	Outstanding 9/30/2010 (c)	Outstanding 10/31/2010 (d)	Outstanding 11/30/2010 (e)	Outstanding 12/31/2010 (f)	Outstanding 1/31/2011 (g)	Outstanding 2/28/2011 (h)	Outstanding 3/31/2011 (i)	Outstanding 4/30/2011 (j)	Outstanding 5/31/2011 (k)	Outstanding 6/30/2011 (l)	Outstanding 7/31/2011 (m)	Outstanding 8/31/2011 (n)	Outstanding 9/30/2011 (o)
1	9.76% Sr Note J Hancock due 2004/ RET 2013	10/11/89	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	9.57% Sr Note Var Annuity Life due 2006/RET 2013	09/30/91	-	-	-	-	-	-	-	-	-	-	-	-	-
3	7.95% Sr Note Var Annuity Life due 2006/RET 2013	08/31/92	-	-	-	-	-	-	-	-	-	-	-	-	-
4	8.07% Sr Note Var Annuity Life due 2006/RET 2013	11/14/94	-	-	-	-	-	-	-	-	-	-	-	-	-
5	8.26% Sr Note NY Life due 2014/RET 2013	11/14/94	-	-	-	-	-	-	-	-	-	-	-	-	-
6	9.40% First Mortgage Bond J due May 2021/RET 2005	04/01/91	-	-	-	-	-	-	-	-	-	-	-	-	-
7	10% Senior Notes due Dec 2011	12/31/91	2,303,308	2,303,308	2,303,308	2,303,308	2,303,308	2,303,308	2,303,308	2,303,308	2,303,308	2,303,308	2,303,308	2,303,308	-
8	7.38% Senior Notes due May 2011	05/22/01	350,000,000	350,000,000	350,000,000	350,000,000	350,000,000	350,000,000	350,000,000	350,000,000	-	-	-	-	-
9	6.75% Debentures Unsecured due July 2028	07/27/98	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000	150,000,000
10	5.125% Senior Notes due Feb 2013	01/13/03	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000
11	10.43% First Mortgage Bond P due 2017 (eff 2012)	11/01/87	-	-	-	-	-	-	-	-	-	-	-	-	-
12	9.75% First Mortgage Bond Q due Apr 2020/RET 2005	04/01/90	-	-	-	-	-	-	-	-	-	-	-	-	-
13	9.32% First Mortgage Bond T due June 2021/RET 2005	06/01/91	-	-	-	-	-	-	-	-	-	-	-	-	-
14	8.77% First Mortgage Bond U due May 2022/RET 2005	05/01/92	-	-	-	-	-	-	-	-	-	-	-	-	-
15	7.50% First Mortgage Bond V due Dec 2007/RET 2005	12/01/92	-	-	-	-	-	-	-	-	-	-	-	-	-
16	6.67% MTN A1 due Dec 2025	12/15/95	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
17	6.27% MTN A2 due Dec 2010	12/19/95	10,000,000	10,000,000	10,000,000	-	-	-	-	-	-	-	-	-	-
18	Sr Note 3Yr Floating due 10/15/2007	10/22/04	-	-	-	-	-	-	-	-	-	-	-	-	-
19	4.00% Sr Note due 10/15/2009	10/22/04	-	-	-	-	-	-	-	-	-	-	-	-	-
20	4.95% Sr Note due 10/15/2014	10/22/04	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000	500,000,000
21	5.95% Sr Note due 10/15/2034	10/22/04	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000	200,000,000
22	6.35% Sr Note due 6/15/2017	6/2007	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000	250,000,000
23	Sr Note 5.50% Due 06/15/2041	6/10/2011										400,000,000	400,000,000	400,000,000	400,000,000
24	8.50% Sr Note due 3/15/2019	03/23/09	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000	450,000,000
25	Subtotal -- Utility Long-Term Debt		$ 2,172,303,308	$ 2,172,303,308	$ 2,172,303,308	$ 2,162,303,308	$ 2,162,303,308	$ 2,162,303,308	$ 2,162,303,308	$ 2,162,303,308	$ 1,812,303,308	$ 2,212,303,308	$ 2,212,303,308	$ 2,212,303,308	$ 2,210,000,000
26															
27															
28	United Cities Propane Gas, Inc.														
29	Baxter, KY -- Harlan LP due 03/05		-	-	-	-	-	-	-	-	-	-	-	-	-
30	Evensville, TN -- E-Con due 06/08		-	-	-	-	-	-	-	-	-	-	-	-	-
31	Pulaski -- Ingas, Ingram & Carvell 06/08		-	-	-	-	-	-	-	-	-	-	-	-	-
32	Boone, NC -- High Country, Kirby 02/04		-	-	-	-	-	-	-	-	-	-	-	-	-
33	Total Propane		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34															
35	United Cities Gas Storage, Inc.														
36	Nations Bk Sr Sec Notes #18 #26 03/07	1991	-	-	-	-	-	-	-	-	-	-	-	-	-
37															
38	Atmos Leasing, Inc.														
39	Industrial Develop Revenue Bond 07/13	1991	392,856	392,856	392,856	392,856	327,379	327,379	327,379	327,379	327,379	327,379	261,903	261,903	261,903
40	Atmos Power Sys - Wells Fargo 05/08	2003	-	-	-	-	-	-	-	-	-	-	-	-	-
41	US Bancorp - 04/09	2004	-	-	-	-	-	-	-	-	-	-	-	-	-
42	**Total Long-Term Debt**		$ 2,172,696,164	$ 2,172,696,164	$ 2,172,696,164	$ 2,162,696,164	$ 2,162,630,687	$ 2,162,630,687	$ 2,162,630,687	$ 2,162,630,687	$ 1,812,630,687	$ 2,212,630,687	$ 2,212,565,211	$ 2,212,565,211	$ 2,210,261,903
43	Less Unamortized Debt Discount		3,014,014	2,990,478	2,966,942	2,943,406	2,919,869	2,896,333	2,872,797	2,851,013	2,827,476	4,090,112	4,064,747	4,039,383	4,014,018
44	Annualized Amortization of Debt Exp. & Debt Dsct.														25,365
45															$ 2,206,247,885
46	Effective Avg Cost of Consol Debt														
47	Utility Only														

Atmos Energy Corporation

Consolidated & Utility Long-Term Debt Outstanding w/ calculatio
as of September 30, 2011

Line	Atmos Energy Corp., Consolidated: Debt Series (a)	Issued (b)	End Int Rate (p)	Annual Int at 9/30/2011 (q)	(r)	Outstanding 13 mth Average (s)	Avg Int Rate (t)	Annual Int 13 mth Average (u)	(v)	Annualized 4270 Amort for T-lock (w)	Annualized 4280-81 Amort Debt Exp&Dsct (x)	Unamort Debt Exp 1810 Penalty 1890 Dsct 2260 9/30/2011 (y)
1	9.76% Sr Note J Hancock due 2004/ RET 2013	10/11/89	9.76%	0		-	9.76%	0			1,362	13,396
2	9.57% Sr Note Var Annuity Life due 2006/RET 2013	09/30/91	9.57%	0		-	9.57%	0			2,908	3,877
3	7.95% Sr Note Var Annuity Life due 2006/RET 2013	08/31/92	7.95%	0		-	7.95%	0			1,435	2,034
4	8.07% Sr Note Var Annuity Life due 2006/RET 2013	11/14/94	8.07%	0		-	8.07%	0			3,771	5,656
5	8.26% Sr Note NY Life due 2014/RET 2013	11/14/94	8.26%	0		-	8.26%	0			7,050	9,987
6	9.40% First Mortgage Bond J due May 2021/RET 2005	04/01/91	9.40%	0		-	9.40%	0			560,397	5,417,176
7	10% Senior Notes due Dec 2011	12/31/91	10.00%	0		2,126,130	10.00%	212,613			0	0
8	7.38% Senior Notes due May 2011	05/22/01	7.38%	0		215,384,615	7.38%	15,884,615			618,637	48,334
9	6.75% Debentures Unsecured due July 2028	07/27/98	6.75%	10,125,000		150,000,000	6.75%	10,125,000			99,938	1,682,294
10	5.125% Senior Notes due Feb 2013	01/13/03	5.13%	12,812,500		250,000,000	5.13%	12,812,500			1,033,655	1,378,206
11	10.43% First Mortgage Bond P due 2017 (eff 2012)	11/01/87	10.43%	0		-	10.43%	0			33,840	205,840
12	9.75% First Mortgage Bond Q due Apr 2020/RET 2005	04/01/90	9.75%	0		-	9.75%	0			337,581	2,897,568
13	9.32% First Mortgage Bond T due June 2021/RET 2005	06/01/91	9.32%	0		-	9.32%	0			362,746	3,506,549
14	8.77% First Mortgage Bond U due May 2022/RET 2005	05/01/92	8.77%	0		-	8.77%	0			368,719	3,902,277
15	7.50% First Mortgage Bond V due Dec 2007/RET 2005	12/01/92	7.50%	0		-	7.50%	0			0	0
16	6.67% MTN A1 due Dec 2025	12/15/95	6.67%	667,000		10,000,000	6.67%	667,000			7,790	111,560
17	6.27% MTN A2 due Dec 2010	12/19/95	6.27%	0		2,307,692	6.27%	144,692			0	0
18	Sr Note 3Yr Floating due 10/15/2007	10/22/04	5.73%	0		-	5.73%	0			20,167	115,963
19	4.00% Sr Note due 10/15/2009	10/22/04	4.00%	0		-	4.00%	0		(155,690)	524,860	(209,377)
20	4.95% Sr Note due 10/15/2014	10/22/04	4.95%	24,750,000		500,000,000	4.95%	24,750,000		3,237,793	3,500	4,507,489
21	5.95% Sr Note due 10/15/2034	10/22/04	5.95%	11,900,000		200,000,000	5.95%	11,900,000		(7,047)	40,533	3,191,352
22	6.35% Sr Note due 6/15/2017	6/2007	6.35%	15,875,000		250,000,000	6.35%	15,875,000		(474,980)	286,874	3,239,363
23	Sr Note 5.50% Due 06/15/2041	6/10/2011	5.50%	22,000,000		33,333,333	5.50%	1,833,333		(669,302)		5,522,472
24	8.50% Sr Note due 3/15/2019	03/23/09	8.50%	38,250,000		450,000,000	8.50%	38,250,000		77,734	1,161,169	3,611,107
25	Subtotal -- Utility Long-Term Debt			$ 136,379,500		$ 2,063,151,771		$ 132,454,754		$ 2,008,508	$ 5,476,934	$ 39,163,122
26												
27												
28	United Cities Propane Gas, Inc.											
29	Baxter, KY -- Harlan LP due 03/05		7.50%	-		-	7.50%	-				
30	Evensville, TN -- E-Con due 06/08		7.00%	-		-	7.00%	-				
31	Pulaski -- Ingas, Ingram & Carvell 06/08		8.25%	-		-	8.25%	-				
32	Boone, NC -- High Country, Kirby 02/04		7.50%	-		-	7.50%	-				
33	Total Propane			$ -		$ -		$ -				
34												
35	United Cities Gas Storage, Inc.											
36	Nations Bk Sr Sec Notes #18 #26 03/07	1991	7.45%	-		-	7.45%	-				
37												
38	Atmos Leasing, Inc.											
39	Industrial Develop Revenue Bond 07/13	1991	7.90%	20,690		332,416	7.90%	26,261				
40	Atmos Power Sys - Wells Fargo 05/08	2003	5.65%	-		-	5.65%	-				
41	US Bancorp - 04/09	2004	5.29%	-		-	5.29%	-				
42	**Total Long-Term Debt**			$ 136,400,190		$ 2,063,484,188		$ 132,481,015				
43	Less Unamortized Debt Discount					3,268,507						
44	Annualized Amortization of Debt Exp. & Debt Dsct.			$ 7,485,442				$ 7,485,442				
45				$ 143,885,632		$ 2,060,215,681		$ 139,966,457				
46	Effective Avg Cost of Consol Debt		**6.52%**	end of period			**6.79%**	13 mth avg				
47	Utility Only											

Atmos Energy Corporation

Consolidated Long-Term Debt Outstanding w/ calculation of Effective Interest Rates as of September 30, 2008; September 30, 2009 and September 30, 2010

Atmos Energy Corp., Consolidated:

Line	Debt Series	Issued	Outstanding 9/30/2008	9/30/2008 Int Rate	Annual Int at 9/30/2008	Outstanding 9/30/2009	9/30/2009 Int Rate	Annual Int at 9/30/2009	Outstanding 9/30/2010	9/30/2010 Int Rate	Annual Int at 9/30/2010
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	9.76% Sr Note J Hancock due 2004/ RET 2013	10/11/89	$ -	9.76%	$ -	$ -	9.76%	$ -	$ -	9.76%	$ -
2	9.57% Sr Note Var Annuity Life due 2006/RET 2013	09/30/91	-	9.57%	0	-	9.57%	0	-	9.57%	0
3	7.95% Sr Note Var Annuity Life due 2006/RET 2013	08/31/92	-	7.95%	0	-	7.95%	0	-	7.95%	0
4	8.07% Sr Note Var Annuity Life due 2006/RET 2013	11/14/94	-	8.07%	0	-	8.07%	0	-	8.07%	0
5	8.26% Sr Note NY Life due 2014/RET 2013	11/14/94	-	8.26%	0	-	8.26%	0	-	8.26%	0
6	9.40% First Mortgage Bond J due May 2021/RET 2005	04/01/91	-	9.40%	0	-	9.40%	0	-	9.40%	0
7	10% Senior Notes due Dec 2011	12/31/91	2,303,308	10.00%	230,331	2,303,308	10.00%	230,331	2,303,308	10.00%	230,331
8	7.38% Senior Notes due May 2011	05/22/01	350,000,000	7.38%	25,812,500	350,000,000	7.38%	25,812,500	350,000,000	7.38%	25,812,500
9	6.75% Debentures Unsecured due July 2028	07/27/98	150,000,000	6.75%	10,125,000	150,000,000	6.75%	10,125,000	150,000,000	6.75%	10,125,000
10	5.125% Senior Notes due Feb 2013	01/13/03	250,000,000	5.13%	12,812,500	250,000,000	5.13%	12,812,500	250,000,000	5.13%	12,812,500
11	10.43% First Mortgage Bond P due 2017 (eff 2012)	11/01/87	-	10.43%	0	-	10.43%	0	-	10.43%	0
12	9.75% First Mortgage Bond Q due Apr 2020/RET 2005	04/01/90	-	9.75%	0	-	9.75%	0	-	9.75%	0
13	9.32% First Mortgage Bond T due June 2021/RET 2005	06/01/91	-	9.32%	0	-	9.32%	0	-	9.32%	0
14	8.77% First Mortgage Bond U due May 2022/RET 2005	05/01/92	-	8.77%	0	-	8.77%	0	-	8.77%	0
15	7.50% First Mortgage Bond V due Dec 2007/RET 2005	12/01/92	-	7.50%	0	-	7.50%	0	-	7.50%	0
16	6.67% MTN A1 due Dec 2025	12/15/95	10,000,000	6.67%	667,000	10,000,000	6.67%	667,000	10,000,000	6.67%	667,000
17	6.27% MTN A2 due Dec 2010	12/19/95	10,000,000	6.27%	627,000	10,000,000	6.27%	627,000	10,000,000	6.27%	627,000
18	Sr Note 3Yr Floating due 10/15/2007	10/22/04	-	5.73%	0	-	5.73%	0	-	5.73%	0
19	4.00% Sr Note due 10/15/2009	10/22/04	400,000,000	4.00%	16,000,000	-	4.00%	0	-	4.00%	0
20	4.95% Sr Note due 10/15/2014	10/22/04	500,000,000	4.95%	24,750,000	500,000,000	4.95%	24,750,000	500,000,000	4.95%	24,750,000
21	5.95% Sr Note due 10/15/2034	10/22/04	200,000,000	5.95%	11,900,000	200,000,000	5.95%	11,900,000	200,000,000	5.95%	11,900,000
22	6.35% Sr Note due 6/15/2017	06/15/07	250,000,000	6.35%	15,875,000	250,000,000	6.35%	15,875,000	250,000,000	6.35%	15,875,000
23	8.50% Sr Note due 3/15/2019	03/23/09	-		-	450,000,000	8.50%	38,250,000	450,000,000	8.50%	38,250,000
24	Subtotal -- Utility Long-Term Debt		$ 2,122,303,308		$118,799,331	$ 2,172,303,308		$ 141,049,331	$ 2,172,303,308		$ 141,049,331
25											
26											
27	United Cities Propane Gas, Inc.										
28	Baxter, KY -- Harlan LP due 03/05		-	7.50%	-	-	7.50%	-	-	7.50%	-
29	Evensville, TN -- E-Con due 06/08		-	7.00%	-	-	7.00%	-	-	7.00%	-
30	Pulaski -- Ingas, Ingram & Carvell 06/08		-	8.25%	-	-	8.25%	-	-	8.25%	-
31	Boone, NC -- High Country, Kirby 02/04		-	7.50%	-	-	7.50%	-	-	7.50%	-
32	Total Propane		$ -		$ -	$ -		$ -	$ -		$ -
33											
34	United Cities Gas Storage, Inc.										
35	Nations Bk Sr Sec Notes #18 #26 03/07	1991	-	7.45%	-	-	7.45%	-	-	7.45%	-
36											
37	Atmos Leasing, Inc.										
38	Industrial Develop Revenue Bond 07/13	1991	654,761	7.90%	51,726	523,808	7.90%	41,381	392,856	7.90%	31,036
39	Atmos Power Sys - Wells Fargo 05/08	2003	-	5.65%	-	-	5.65%	-	-	5.65%	-
40	US Bancorp - 04/09	2004	653,578	5.29%	34,574	-	5.29%	-	-	5.29%	-
41	**Total Long-Term Debt**		$ 2,123,611,647		$118,885,631	$ 2,172,827,116		$ 141,090,712	$ 2,172,696,164		$ 141,080,366
42	Less Unamortized Debt Discount		$ 3,035,041			$ 3,296,449			$ 3,014,014		
43	Annualized Amortization of Debt Exp. & Debt Dsct.				$ 10,287,280			$ 8,053,886			$ 8,053,886
44			$ 2,120,576,606		$129,172,911	$ 2,169,530,667		$ 149,144,598	$ 2,169,682,149		$ 149,134,253
45	Effective Avg Cost of Consol Debt			6.09%	end of period		6.87%	end of period		6.87%	end of period

Note: includes current maturities

Atmos Energy Corporation
Consolidated Long-Term Debt - Unamortized Discount Acct 2260
as of September 30, 2008; September 30, 2009 and September 30, 2010

WP 7A-1

Atmos Energy Corp., Consolidated:

Line	Debt Series (a)	Year Issued (b)	Full Dsct before Amort (c)	4280 monthly amort. (d)	2260 Balance Unamortized Discount 9/30/2008 (e)	2260 Balance Unamortized Discount 9/30/2009 (f)	2260 Balance Unamortized Discount 9/30/2010 (g)
1	7.38% Senior Notes due May 2011	2001	$ 210,000	$ 1,750	$ 54,042	$ 32,792	$ 11,542
2	6.75% Debentures Unsecured due July 2028	1998	1,327,500	3,687.50	877,625	833,375	789,125
3	5.125% Senior Notes due Feb 2013	2003	212,500	1,770.83	92,292	71,292	50,292
4	4.00% Sr Note due 10/15/2009	2004	1,568,000	26,133.33	339,733	156,800	156,800
5	4.95% Sr Note due 10/15/2014	2004	35,000	291.67	21,292	17,792	14,292
6	5.95% Sr Note due 10/15/2034	2004	1,216,000	3,377.78	1,057,244	1,016,711	976,178
7	6.35% Sr Note due 6/15/2017	2007	677,500	5,646	592,813	525,063	457,313
8	8.50% Sr Note due 3/15/2019	2009				642,625	558,474
9	Subtotal -- Utility Long-Term Debt Unamortized Discount		$ 5,246,500	$ 42,656.94	$ 3,035,041	$ 3,296,449	$ 3,014,014

Atmos Energy Corporation
Annualized Amortization of Debt Expense and Debt Discount
as of September 30, 2008; September 30, 2009 and proforma September 30, 2010

Atmos Energy Corp., Consolidated:

Line	Debt Series (a)	9/30/2008 Annualized 4270 Amort for T-lock (b)	9/30/2008 Annualized 4280-81 Amort Debt Exp&Dsct (c)	9/30/2009 Annualized 4270 Amort for T-lock (d)	9/30/2009 Annualized 4280-81 Amort Debt Exp&Dsct (e)	9/30/2010 Annualized 4270 Amort for T-lock (f)	9/30/2010 Annualized 4280-81 Amort Debt Exp&Dsct (g)
1	9.76% Sr Note J Hancock due 2004/ RET 2013		$ 1,362		$ 1,362		$ 1,362
2	9.57% Sr Note Var Annuity Life due 2006/RET 2013		2,908		2,908		2,908
3	7.95% Sr Note Var Annuity Life due 2006/RET 2013		1,435		1,435		1,435
4	8.07% Sr Note Var Annuity Life due 2006/RET 2013		3,771		3,771		3,771
5	8.26% Sr Note NY Life due 2014/RET 2013		7,050		7,050		7,050
6	9.40% First Mortgage Bond J due May 2021/RET 2005		560,397		560,397		560,397
7	10% Senior Notes due Dec 2011		0		0		0
8	7.38% Senior Notes due May 2011		502,339		502,339		502,339
9	6.75% Debentures Unsecured due July 2028		99,938		99,938		99,938
10	5.125% Senior Notes due Feb 2013		1,033,655		1,033,655		1,033,655
11	10.43% First Mortgage Bond P due 2017 (eff 2012)		33,840		33,840		33,840
12	9.75% First Mortgage Bond Q due Apr 2020/RET 2005		337,581		337,581		337,581
13	9.32% First Mortgage Bond T due June 2021/RET 2005		362,746		362,746		362,746
14	8.77% First Mortgage Bond U due May 2022/RET 2005		368,719		368,719		368,719
15	7.50% First Mortgage Bond V due Dec 2007/RET 2005		0		0		0
16	6.67% MTN A1 due Dec 2025		7,790		7,790		7,790
17	6.27% MTN A2 due Dec 2010		15,441		15,441		15,441
18	Sr Note 3Yr Floating due 10/15/2007		20,167		20,167		20,167
19	4.00% Sr Note due 10/15/2009	$ 2,320,733	995,873	$ (155,690)	524,860	$ (155,690)	524,860
20	4.95% Sr Note due 10/15/2014	3,237,793	453,170	3,237,793	3,500	3,237,793	3,500
21	5.95% Sr Note due 10/15/2034	(7,047)	115,724	(7,047)	40,533	(7,047)	40,533
22	6.35% Sr Note due 6/15/2017	(474,980)	286,874	(474,980)	286,874	(474,980)	286,874
23	8.50% Sr Note due 3/15/2019			77,734	1,161,169	77,734	1,161,169
24	Subtotal -- Utility Long-Term Debt	$ 5,076,499	$ 5,210,781	$ 2,677,809	$ 5,376,077	$ 2,677,809	$ 5,376,077
25							
26							
27	United Cities Gas Storage, Inc.						
28	Nations Bk Sr Sec Notes #18 #26 03/07		0		0		(0)
29							
30							
31	Annualized Amortization of Debt Exp. & Debt Dsct.	$ 5,076,499	$ 5,210,781	$ 2,677,809	$ 5,376,077	$ 2,677,809	$ 5,376,077

Kansas Distribution System
Interest coverage computation - Atmos Consolidated
Twelve Months Ended September 30, 2011
Kansas
Section 7 (iii) Interest Coverage

Line No.	Description	12/31/2008	12/31/2009	12/31/2010	9/30/2010	9/30/2011
	(a)	(b)	(c)	(d)	(e)	(f)
1	Net Income before interest and income taxe:	$435,103,068	$471,533,770	$458,142,629	$489,097,391	$477,734,803
2						
3	Interest expense	$137,109,966	$146,981,754	$151,728,569	$150,611,732	$149,252,139
4	Capitalized interest	2,986,143	5,565,438	2,952,077	3,859,831	1,690,298
5	Total interest expense	$140,096,110	$152,547,192	$154,680,646	$154,471,562	$150,942,437
6						
7	Times interest earned before income taxes	3.11	3.09	2.96	3.17	3.17

Source: See Relied File 5a (for line 1)
See Relied File 5b (for lines 3 & 4)

Section 8 A
Item (i)

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEET

	September 30		December 31		
ASSETS	**2011**	**2010**	**2010**	**2009**	**2008**
Property, plant and equipment	$ 6,607,552	$ 6,384,396	$ 6,638,718	$ 6,196,043	$ 5,803,491
Construction in progress	209,242	157,922	NA	NA	NA
	6,816,794	6,542,318	6,638,718	6,196,043	5,803,491
Less accumulated depreciation and amortization	1,668,876	1,749,243	1,779,374	1,672,855	1,608,743
Net property, plant & equipment	5,147,918	4,793,075	4,859,344	4,523,188	4,194,748
Current assets					
Cash and cash equivalents	131,419	131,952	129,892	174,829	69,799
Accounts receivable, net	273,303	273,207	564,934	597,012	833,125
Gas stored underground	289,760	319,038	339,105	399,582	582,743
Other current assets and prepayments	316,471	150,995	229,324	115,155	197,441
Total current assets	1,010,953	875,192	1,263,255	1,286,578	1,683,108
Goodwill and intangible assets	740,207	740,148	739,991	739,907	738,929
Deferred charges and other assets	383,793	355,376	359,033	325,751	202,114
	$ 7,282,871	$ 6,763,791	$ 7,221,623	$ 6,875,424	$ 6,818,899

CAPITALIZATION AND LIABILITIES	**2011**	**2010**	**2010**	**2009**	**2008**
Shareholders' equity					
Common Stock	$ 451	$ 451	$ 453	$ 465	$ 458
Additional paid in capital	1,732,935	1,714,364	1,724,899	1,802,606	1,757,834
Retained earnings	(48,460)	(23,372)	529,900	467,449	381,633
Accum. Other comprehensive income (loss)	570,495	486,905	19,601	(12,444)	(61,849)
Shareholders' equity	2,255,421	2,178,348	2,274,853	2,258,076	2,078,076
Long-term debt	2,206,117	1,809,551	1,807,319	2,159,470	1,719,920
Total capitalization	4,461,538	3,987,899	4,082,172	4,417,546	3,797,996
Current liabilities					
Accounts payable and accrued liabilities	291,205	266,208	510,085	578,805	815,095
Other current liabilities	367,563	413,640	349,914	413,754	441,481
Short-term debt	206,396	126,100	247,993	179,712	360,833
Current maturities of long-term debt	2,434	360,131	352,434	10,131	400,507
Total current liabilities	867,598	1,166,079	1,460,426	1,182,402	2,017,916
Deferred income taxes	960,093	829,128	892,090	588,423	431,324
Regulatory cost of removal obligation	428,947	350,521	354,871	314,126	305,784
Deferred credits and other liabilities	564,695	430,164	432,064	372,927	265,879
	$ 7,282,871	$ 6,763,791	$ 7,221,623	$ 6,875,424	$ 6,818,899

Section 8 B
Item (ii)

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31	
	2009	2008
Operating Revenues		
Natural gas distribution segment	$ 2,731,691	$ 3,782,921
Regulated transmission and storage segment	201,836	205,553
Natural gas marketing segment	2,093,623	4,234,640
Pipeline, storage and other segment	37,099	41,430
Intersegment eliminations	(518,649)	(984,417)
	4,545,600	7,280,127
Purchse gas cost		
Natural gas distribution segment	1,710,820	2,751,671
Natural gas marketing segment	1,979,249	4,157,559
Pipeline, storage and other segment	10,158	6,570
Intersegment eliminations	(516,966)	(982,573)
	3,183,261	5,933,227
Gross Profit	1,362,339	1,346,900
Operating expenses		
Operation and maintenance	485,195	511,722
Depreciation and amortization	217,921	205,055
Taxes, other than income	181,115	195,465
Asset impairments	3,304	2,078
Total operating expenses	887,535	914,320
Operating income	474,804	432,580
Miscellaneous income (expense), net	(3,271)	2,523
Interest charges	152,547	140,096
Income before income taxes	318,986	295,007
Income tax expense	110,641	112,516
Income from continuing operations	208,345	182,491
Income from discontinued operations		
Net Income	$ 208,345	$ 182,491
Per share data		
Basic net income per share	$ 2.25	$ 2.00
Diluted net income per share	$ 2.24	$ 2.00
Weighted average shares outstanding:		
Basic	92,152	90,471
Diluted	92,509	90,769

Section 8 B
Item (ii)

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		Year Ended December 31
	2011	2010	2010
Operating Revenues			
Natural gas distribution segment	$ 2,531,863	$ 2,842,638	$ 2,766,939
Regulated transmission and storage segment	219,373	203,013	205,160
Nonregulated segment	2,024,893	2,146,658	2,074,282
Intersegment eliminations	(428,495)	(472,474)	(462,403)
	4,347,634	4,719,835	4,583,978
Purchse gas cost			
Natural gas distribution segment	1,487,499	1,820,627	1,739,783
Nonregulated segment	1,959,893	2,032,567	2,004,788
Intersegment eliminations	(426,999)	(470,864)	(460,809)
	3,020,393	3,382,330	3,283,762
Gross Profit	1,327,241	1,337,505	1,300,216
Operating expenses			
Operation and maintenance	449,290	460,513	453,245
Depreciation and amortization	227,099	211,589	213,911
Taxes, other than income	178,683	188,252	186,396
Asset impairments	30,270		-
Total operating expenses	885,342	860,354	853,552
Operating income	441,899	477,151	446,664
Miscellaneous income (expense), net	21,499	(156)	(624)
Interest charges	150,825	154,360	154,569
Income before income taxes	312,573	322,635	291,471
Income tax expense	113,689	124,362	112,531
Income from continuing operations	198,884	198,273	178,940
Income from discontinued operations	8,717	7,566	$ 7,566
Net Income	$ 207,601	$ 205,839	$ 186,506
Per share data			
Basic net income per share	$ 2.28	$ 2.22	$ 2.03
Diluted net income per share	$ 2.27	$ 2.20	$ 2.01
Weighted average shares outstanding:			
Basic	90,201	91,852	90,082
Diluted	90,652	92,422	90,408

Atmos Energy Corporation
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock			Accumulated		
	Number of Shares	Stated Value	Additional Paid-in Capital	Other Comprehensive Income (loss)	Retained Earnings	Total
	(In thousands, except share data)					
Balance, September 30, 2004	62,799,710	$ 314	$ 1,005,644	$ (14,529)	$ 142,030	$ 1,133,459
Comprehensive income:						
Net income	-	-	-	-	135,785	135,785
Unrealized holding gains on investments, net	-	-	-	1,528	-	1,528
Treasury lock agreements, net	-	-	-	(2,714)	-	(2,714)
Cash flow hedges, net	-	-	-	12,374	-	12,374
Total comprehensive income						146,973
Cash dividends	-	-	-	-	(98,978)	(98,978)
Common stock issued						
Public offering	16,100,000	80	381,271	-	-	381,351
Direct stock purchase plan	450,212	3	12,486	-	-	12,489
Retirement savings plan	441,350	2	11,767	-	-	11,769
Long-term incentive plan	745,788	4	14,116	-	-	14,120
Employee stock-based compensation	-	-	1,175	-	-	1,175
Outside directors stock-for-fee plan	2,341	-	64	-	-	64
Balance, September 30, 2005	80,539,401	403	1,426,523	(3,341)	178,837	1,602,422
Comprehensive income:						
Net income	-	-	-	-	147,737	147,737
Unrealized holding gains on investments, net	-	-	-	882	-	882
Treasury lock agreements, net	-	-	-	3,442	-	3,442
Cash flow hedges, net	-	-	-	(44,833)	-	(44,833)
Total comprehensive income						107,228
Cash dividends	-	-	-	-	(102,275)	(102,275)
Common stock issued						
Direct stock purchase plan	387,833	2	10,391	-	-	10,393
Retirement savings plan	442,635	2	11,918	-	-	11,920
Long-term incentive plan	366,905	2	8,976	-	-	8,978
Long-term stock plan for Mid-States Div	300	-	5	-	-	5
Employee stock-based compensation	-	-	9,361	-	-	9,361
Outside directors stock-for-fee plan	2,442	-	66	-	-	66
Balance, September 30, 2006	81,739,516	409	1,467,240	(43,850)	224,299	1,648,098
Comprehensive income:						
Net income	-	-	-	-	168,492	168,492
Unrealized holding gains on investments, net	-	-	-	1,241	-	1,241
Treasury lock agreements, net	-	-	-	6,288	-	6,288
Cash flow hedges, net	-	-	-	20,123	-	20,123
Total comprehensive income						196,144
Cash dividends	-	-	-	-	(111,664)	(111,664)
Common stock issued						
Public offering	6,325,000	32	191,881	-	-	191,913
Direct stock purchase plan	325,338	2	9,866	-	-	9,868
Retirement savings plan	422,646	2	12,929	-	-	12,931
Long-term incentive plan	511,584	2	7,547	-	-	7,549
Employee stock-based compensation	-	-	10,841	-	-	10,841
Outside directors stock-for-fee plan	2,453	-	74	-	-	74
Balance, September 30, 2007	89,326,537	447	1,700,378	(16,198)	281,127	1,965,754
Comprehensive income:						
Net income	-	-	-	-	180,331	180,331
Unrealized holding losses on investments, net	-	-	-	(1,897)	-	(1,897)
Treasury lock agreements, net	-	-	-	3,148	-	3,148
Cash flow hedges, net	-	-	-	(21,000)	-	(21,000)
Total comprehensive income						160,582
Retroactive charge to record initial uncertain tax positions	-	-	-	-	(569)	(569)
Cash dividends	-	-	-	-	(117,288)	(117,288)
Common stock issued						
Direct stock purchase plan	388,485	2	10,333	-	-	10,335
Retirement savings plan	558,014	3	15,116	-	-	15,119
Long-term incentive plan	538,450	2	5,592	-	-	5,594
Employee stock-based compensation	-	-	12,878	-	-	12,878
Outside directors stock-for-fee plan	3,197	-	87	-	-	87
Balance, September 30, 2008	90,814,683	454	1,744,384	(35,947)	343,601	2,052,492

Atmos Energy Corporation
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock Number of Shares	Common Stock Stated Value	Additional Paid-in Capital	Accumulated Other Comprehensive Income (loss)	Retained Earnings	Total
			(In thousands, except share data)			
Comprehensive income:						
Net income	-	-	-	-	190,978	190,978
Unrealized holding losses on investments, net	-	-	-	(1,820)	-	(1,820)
Other than temporary impairment of investments, net	-	-	-	3,370	-	3,370
Treasury lock agreements, net	-	-	-	3,606	-	3,606
Cash flow hedges, net	-	-	-	10,607	-	10,607
Total comprehensive income						206,741
Changes in measurement date for employee benefit plan	-	-	-	-	(7,766)	(7,766)
Cash dividends	-	-	-	-	(121,460)	(121,460)
Common stock issued						
Direct stock purchase plan	407,262	2	8,743	-	-	8,745
Retirement savings plan	640,639	3	16,571	-	-	16,574
Long-term incentive plan	686,046	4	8,075	-	-	8,079
Employee stock-based compensation	-	-	13,280	-	-	13,280
Outside directors stock-for-fee plan	3,079	-	76	-	-	76
Balance, September 30, 2009	92,551,709	$ 463	$ 1,791,129	$ (20,184)	$ 405,353	$ 2,176,761
Comprehensive income:						
Net income					205,839	205,839
Unrealized holding losses on investments, net				1,745		1,745
Treasury lock agreements, net				2,030		2,030
Cash flow hedges, net				(6,963)		(6,963)
Total comprehensive income						202,651
Repurchase of common stock.	(2,958,580)	(15)	(100,435)			(100,450)
Repurchase of equity awards	(37,365)		(1,191)			(1,191)
Cash dividends					(124,287)	(124,287)
Common stock issued						
Direct stock purchase plan	103,529	1	2,881			2,882
Retirement savings plan	79,722		2,281			2,281
Long-term incentive plan	421,706	2	8,708			8,710
Employee stock-based compensation			10,894			10,894
Outside directors stock-for-fee plan	3,382		97			97
Balance, September 30, 2010	90,164,103	451	1,714,364	(23,372)	486,905	2,178,348
Comprehensive income:						
Net income					207,601	207,601
Unrealized holding losses on investments, net				(1,647)		(1,647)
Treasury lock agreements, net				(28,689)		(28,689)
Cash flow hedges, net				5,248		5,248
Total comprehensive income						182,513
Repurchase of common stock.	(375,468)	(2)	2			-
Repurchase of equity awards	(169,793)	(1)	(5,298)			(5,299)
Cash dividends					(124,011)	(124,011)
Common stock issued						
Direct stock purchase plan			(54)			(54)
Retirement savings plan						-
Long-term incentive plan	675,255	3	13,886			13,889
Employee stock-based compensation			9,958			9,958
Outside directors stock-for-fee plan	2,385		77			77
Balance, September 30, 2011	90,296,482	451	1,732,935	(48,460)	570,495	2,255,421

Line No.	Account #		12 Months Ended September 2011	September 2010	December 2010	December 2009	December 2008
	(a)		(b)	(c)	(d)	(e)	(f)
1	4030	Depreciation Expense	9,351,857	8,908,882	8,992,308	8,650,733	8,386,167
2	4060	Amortization of Gas Plant Acquisition	373,418	373,418	373,418	373,418	369,892
3	4074	Regulatory Credits	(6,224)	(12,533)	(12,155)	(8,143)	(8,534)
4	4081	Taxes other than Income Taxes	6,515,265	6,193,968	6,252,069	6,145,247	6,174,823
5	4091	Income taxes, utility operations	(554,824)	(8,336,440)	(8,336,440)	(2,548,485)	1,717,253
6	4101	Provision for deferred income taxes	4,846,769	11,349,510	11,349,510	4,441,478	(173,471)
7	4150	Revenues from Merchandising, Jobing	-	(37)	(18)	27	128
8	4160	Costs and expenses of merchandising	-	-	-	-	308
9	4170	Revenue from Nonutility Operations	(4,021)	(8,182)	(7,389)	(7,458)	(8,897)
10	4190	Interest and Dividend Income	1,448	(94,046)	(55,199)	(276,196)	(442,195)
11	4210	Misc. Nonoperating Income	(1,567,177)	(324,985)	(332,661)	(201,759)	(1,995)
12	4261	Donations	134,378	84,123	62,697	126,797	53,641
13	4263	Penalties	83	863	615	510	7
14	4264	Civic, Political and Related	38,235	35,414	37,595	36,464	32,428
15	4265	Other Deductions	89,879	89,532	112,963	32,709	137,685
16	4270	Interest on long-term debt	4,145,334	4,556,137	4,480,062	4,784,006	4,416,317
17	4280	Amortization of debt discount and expense	55,168	73,118	66,462	94,032	22,215
18	4281	Amortization of loss on reacquired debt	98,885	96,567	100,413	89,625	22,917
19	4300	Interest on debt to associated companies	15,671	6,741	8,168	5,942	6,264
20	4310	Other interest expense	72,323	98,692	86,033	272,606	604,482
21	4320	Allowance for borrowed funds used during	(44,805)	(75,684)	(70,525)	(83,221)	(83,315)
22	4800	Residential sales	(83,095,419)	(89,346,223)	(88,751,039)	(95,912,669)	(127,854,140)
23	4805	Unbilled Residential Revenue	92	(7,829)	644,186	2,541,893	(723,869)
24	4811	Commercial Revenue-Banner	(22,712,382)	(24,854,588)	(24,660,686)	(26,507,911)	(36,853,517)
25	4812	Industrial Revenue-Banner	(660,372)	(858,271)	(756,424)	(1,345,657)	(1,968,507)
26	4813	Irrigation Revenue-Banner	(6,137,455)	(3,421,695)	(4,231,722)	(1,964,808)	(7,899,249)
27	4815	Unbilled Comm Revenue	29,592	(83,966)	236,107	648,873	378,394
28	4820	Other Sales to Public Authority	(2,003,561)	(2,183,040)	(2,196,488)	(2,410,268)	(3,475,829)
29	4825	Unbilled Public Authority Revenue	1,969	(5,758)	5,016	81,620	85
30	4870	Forfeited discounts	(346,794)	(374,144)	(373,915)	(447,845)	(618,794)
31	4880	Miscellaneous service revenues	(92,633)	(104,262)	(95,215)	(144,037)	(176,258)
32	4890	Revenues from transporation of	(234)	-	-	-	-
33	4895	Revenue-Transportation Commercial	(15,377)	(112,756)	(272,554)	(20,549)	(19,167)
34	4896	Revenue-Transportation Industrial	(3,679,036)	(3,665,307)	(3,313,036)	(3,491,634)	(3,487,105)
35	4950	Other gas revenues	(660,709)	(322,554)	(408,022)	(633,354)	(1,530,506)
36	7520	Production - Gas well expenses	39,461	28,580	28,475	4,276	562
37	7640	Production - Maintenance of field lines	-	-	-	3,093	-
38	7670	Production - Maintenance of purification equipi	-	-	-	1,017	-
39	8001	Intercompany Gas Well-Head Purchase	(14,850)	(81,220)	(67,470)	6,650,920	1,825,470
40	8010	Natural gas field line purchases	1,072,004	1,254,249	1,280,864	1,320,123	2,283,643
41	8040	Natural Gas City Gate Purchase	56,528,916	61,886,321	58,061,374	47,206,068	117,555,714
42	8045	Transportation to City Gate	-	-	-	12,116,957	14,729,941
43	8050	Other Purchases	(4,908)	(15,103)	(9,819)	(20,176)	-
44	8051	PGA for Residential	48,649,620	58,120,263	56,910,598	65,752,904	97,396,279
45	8052	PGA for Commercial	14,741,365	17,298,468	17,088,749	19,188,830	29,425,940
46	8053	PGA for Industrial	477,436	665,705	575,050	1,027,550	1,726,017
47	8054	PGA for Public Authority	1,444,909	1,566,708	1,585,173	1,776,640	2,827,323
48	8055	PGA for Irrigation Sales	5,188,901	2,780,303	3,496,359	1,296,919	7,145,028
49	8057	PGA for Transportation Sales	-	10,448	-	33,512	(2,087)
50	8058	Unbilled PGA Cost	(7,223)	(72,442)	(755,560)	(3,412,082)	(152,817)
51	8059	PGA Offset to Unrecovered Gas	(71,574,578)	(77,139,393)	(75,788,065)	(93,845,646)	(125,126,504)
52	8060	Exchange Gas - Imbalances	(11,336)	84,971	882	(103,422)	194,659
53	8081	Gas Withdrawn from Storage - Debit	18,060,575	15,825,091	18,089,654	35,474,027	26,206,332
54	8082	Gas Withdrawn from Storage - Credit	(20,077,080)	(17,901,775)	(17,692,542)	(12,601,099)	(37,386,844)
55	8120	Gas Used for Other Utility Operations	(116,971)	(149,240)	(144,695)	(162,979)	(282,405)
56	8130	Other Gas Supply Expenses	700	-	-	(8,802)	3,699
57	8140	Natural gas storage - Operation supervision ar	-	-	-	-	34
58	8150	Natural Gas Storage - Maps and records	-	-	-	(203)	-
59	8160	Natural gas storage - Wells expense	651,456	570,551	622,123	204,032	-
60	8180	Natural gas storage - Compressor station expe	-	-	-	-	(903)
61	8190	Natural gas storage - Compressor station fuel	112,899	143,886	138,037	177,367	263,820

Line No.	Account #		12 Months Ended September 2011	September 2010	December 2010	December 2009	December 2008
	(a)		(b)	(c)	(d)	(e)	(f)
62	8240	Natural gas storage - Other expenses	21,090	11,573	11,520	16,813	-
63	8250	Natural gas storage - Storage wells royalties	61,209	59,633	52,961	53,638	66,445
64	8300	Natural gas storage - Maintenance Supervisioı	174	-	174	-	25
65	8310	Natural gas storage - Maintenance of structure	117	-	117	-	-
66	8320	Natural gas storage - Maintenance of reservoiı	3,432	4,978	5,764	1,457	-
67	8340	Natural gas storage - Maintenance of compres	18,289	16,494	13,684	22,336	17,761
68	8350	Natural gas storage - Maintenance of measuriı	-	-	-	-	76
69	8360	Natural gas storage - Maintenance of purificati	16	-	-	-	-
70	8370	Natural gas storage - Maintenance of other eq	-	143	143	-	-
71	8400	Natural gas storage - Operation supervision ar	-	-	-	-	69
72	8410	Natural gas storage - Operation labor and exp	28,502	16,185	18,783	5,156	14
73	8500	Transmission - Operation supervision and eng	-	-	-	467	-
74	8530	Transmission - Compressor station labor and (	-	-	-	16	-
75	8540	Transmission - Gas for compressor station fue	-	53	39	27	50
76	8560	Transmission - Mains expenses	490	701	755	1,958	(1,204)
77	8570	Transmission - Measuring and regulating stati	3,209	2,605	2,612	3,425	2,666
78	8580	Transmission - Transmission and compressioı	16,138,227	16,236,100	16,269,817	3,965,227	-
79	8600	Transmission - Rents	-	-	-	240	838
80	8610	Transmission - Maintenance supervision	55	-	44	-	-
81	8630	Transmission - Maintenance of mains	-	393	393	-	-
82	8650	Transmission - Maintenance of measuring equ	-	-	-	-	325
83	8700	Distribution - Operation Supervision and Engin	903,995	918,803	888,324	944,868	911,685
84	8710	Distribution - Distribution Load Dispatching	8,487	13,436	11,016	19,261	22,472
85	8711	Distribution - Oderization	25,956	4,066	13,156	76	1,211
86	8740	Distribution - Mains and Services Expenses	2,988,247	2,601,895	2,697,856	2,887,941	3,379,563
87	8750	Distribution - Measuring and Regulating Statioı	71,802	49,967	50,912	68,293	54,145
88	8770	Distribution - Measuring and Regulating Statioı	828	43,557	39,790	16,891	31,192
89	8780	Distribution - Meter and House Regulator Expe	448,638	423,357	431,913	417,863	589,273
90	8790	Distribution - Customer Installations Expenses	105,042	107,204	105,130	124,669	179,528
91	8800	Distribution - Other Expenses	325,159	276,475	267,586	339,125	307,209
92	8810	Distribution - Rents	90,662	224,490	214,004	131,327	303,931
93	8850	Distribution - Maintenance Supervision and En	252,030	273,177	255,572	245,446	160,956
94	8860	Distribution - Maintenance of Structures and In	8,278	5,467	6,244	4,013	3,694
95	8870	Distribution - Maintenance of Mains	165,418	141,097	142,680	169,960	180,079
96	8880	Distribution - Maintenance of Compressor Stat	-	-	-	52	987
97	8890	Distribution - Maint. of Measuring and Regulati	102,374	165,397	173,215	80,908	119,551
98	8900	Distribution - Maint. of Measuring and Regulati	462	859	984	2,167	3,678
99	8920	Distribution - Maintenance of Services	18,297	5,218	6,008	11,731	15,845
100	8930	Distribution - Maintenance of Meters and Hous	7,993	27,413	26,830	25,494	96,116
101	8940	Distribution - Maintenance of Other Equipment	129	102	231	-	-
102	9010	Customer Accounts - Supervision	60,282	58,411	59,400	53,058	52,624
103	9020	Customer Accounts - Meter Reading Expense	810,278	751,616	753,522	781,482	743,598
104	9030	Customer Accounts - Customer Records and (	69,524	283,652	231,856	196,225	254,455
105	9040	Customer Accounts - Uncollectible Accounts	662,680	(420)	1,257	(49,070)	804,401
106	9050	Customer Accounts - Miscellaneous Customeı	8,608	7,363	7,578	6,763	11,574
107	9070	Customer Serivce and Informational - Supervis	1,065	6,953	1,503	6,432	2,500
108	9080	Customer Serivce and Informational - Custom	57,185	25,732	27,656	45,985	46,698
109	9090	Customer Serivce and Informational - Informat	6,024	8,994	8,460	6,947	6,281
110	9100	Customer Serivce and Informational - Miscella	42,207	37,466	34,381	16,934	17,716
111	9110	Sales - Supervision	173,261	149,225	155,001	191,049	181,329
112	9120	Sales - Demonstrating and Selling Expenses	18,803	14,976	17,253	14,187	12,385
113	9130	Sales - Advertising Expenses	-	1,961	-	1,961	91
114	9160	Sales - Miscellaneous Sales Expenses	925	-	925	60	1,203
115	9200	A&G - Administrative and General Salaries	231,877	136,671	131,979	56,457	-
116	9210	A&G - Office Supplies and Expenses	25,798	42,092	30,455	21,485	15,496
117	9220	A&G - Administrative Expenses Transferred - (	7,317,066	7,332,136	7,337,493	7,821,642	7,672,903
118	9230	A&G - Outside Services Employed	150,426	65,917	79,767	163,001	502,153
119	9240	A&G - Property Insurance	109,186	112,891	109,299	206,734	218,105
120	9250	A&G - Injuries and Damages	61,456	46,426	48,434	63,186	59,994
121	9260	A&G - Employee Pensions and Benefits	1,672,297	1,474,945	1,501,718	1,490,222	1,457,048
122	9270	A&G - Franchise Requirements	2,484	805	1,833	1,217	853

Line No.	Account #		12 Months Ended September 2011	September 2010	December 2010	December 2009	December 2008
	(a)		(b)	(c)	(d)	(e)	(f)
123	9280	A&G - Regulatory Commission Expenses	97,914	15,179	40,214	26,083	20,133
124	9302	A&G - Miscellaneous General Expense	44,757	44,815	48,079	52,234	47,055
125	9310	A&G - Rents	19,995	22,239	22,763	5,261	-
			(7,206,658)	(5,178,084)	(5,287,596)	(4,857,811)	(5,792,669)

SALES OF NATURAL GAS BY RATE SCHEDULES - KANSAS OPERATIONS ONLY (FOR ALL COMPANIES)

1. Information called for below shall be given for each rate schedule (by number and title) and each special contract (by name of contracting party).
2. Provide a sub-heading and total for each gas service revenue account.
3. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (e.g. 12 if all are billed monthly).

Line No.	Number and Title of Rate Schedule or Name Holder of Special Contract (a)	MCF. Sold @ F. BTU content (b)	Revenue (c)	Average Number of Customers (d)	MCF of Sales per Customer (e)	Revenue per MCF sold (f)
1	**RESIDENTIAL - A/C 480**					
2						
3						
4	Division 81	9,755,130	80,038,697	113,863	85.7	8.20
5						
6	Division 86	326,151	3,056,630	4,003	81.5	9.37
7						
8						
9	**TOTAL**	10,081,281	83,095,327	117,866	85.5	8.24
10	**COMMERCIAL - A/C 481.1**					
11						
12						
13	Division 81	2,798,286	20,805,823	8,845	316.4	7.44
14						
15	Division 86	231,960	1,876,967	502	462.1	8.09
16						
17						
18	**TOTAL**	3,030,246	22,682,790	9,347	324.2	7.49
19	**INDUSTRIAL, SMALL 481.3**					
20						
21						
22	Division 81	94,800	651,630	88	1,077.3	6.87
23						
24	Division 86	-	8,742	0	0.0	0.00
25						
26						
27						
28	**TOTAL**	94,800	660,372	88	1,077.3	6.97
29	**INDUSTRIAL, LARGE 481.4**					
30	NONE	-	0	0	0.0	0.00
31	**TOTAL**	-	0	0	0.0	0.00
32						
33	**IRRIGATION 481.5**					
34	GGS-SW (Southwest Total)	974,591	6,137,455	272	3,583.1	6.30
35	**TOTAL**	974,591	6,137,455	272	3,583.1	6.30
36						
37	**PUBLIC AUTHORITIES 482**	281,716	2,001,591	558	504.9	7.10
38						
39	**TOTAL**	281,716	2,001,591	558	504.9	7.10
40						
41						
42	**TOTAL**	14,462,634	114,577,535	128,131	112.9	7.92
43						
44						

SALES OF NATURAL GAS BY RATE SCHEDULES - KANSAS OPERATIONS ONLY (FOR ALL COMPANIES)

1. Information called for below shall be given for each rate schedule (by number and title) and each special contract (by name of contracting party).
2. Provide a sub-heading and total for each gas service revenue account.
3. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (e.g. 12 if all are billed monthly).

Line No.	Number and Title of Rate Schedule or Name Holder of Special Contract (a)	MCF. Sold @ F. BTU content (b)	Revenue (c)	Average Number of Customers (d)	MCF of Sales per Customer (e)	Revenue per MCF sold (f)
1	**RESIDENTIAL - A/C 480**					
2						
3						
4	Division 81	10,162,597	86,902,732	113,742	89.3	8.55
5						
6	Division 86	358,411	2,451,321	3,989	89.8	6.84
7						
8						
9	TOTAL	10,521,008	89,354,053	117,731	89.4	8.49
10	**COMMERCIAL - A/C 481.1**					
11						
12						
13	Division 81	2,882,623	23,067,433	8,875	324.8	8.00
14						
15	Division 86	326,600	1,871,120	508	642.9	5.73
16						
17						
18	TOTAL	3,209,223	24,938,553	9,383	342.0	7.77
19	**INDUSTRIAL, SMALL 481.3**					
20						
21						
22	Division 81	130,784	853,553	86	1,520.7	6.53
23						
24	Division 86	-	4,717	0	0.0	0.00
25						
26						
27						
28	TOTAL	130,784	858,270	86	1,520.7	6.56
29	**INDUSTRIAL, LARGE 481.4**					
30	NONE	-	0	0	0.0	0.00
31	TOTAL	-	0	0	0.0	0.00
32						
33	**IRRIGATION 481.5**					
34	GGS-SW (Southwest Total)	602,679	3,421,695	272	2,215.7	5.68
35	TOTAL	602,679	3,421,695	272	2,215.7	5.68
36						
37	**PUBLIC AUTHORITIES 482**	313,800	2,188,798	567	553.4	6.98
38						
39	TOTAL	313,800	2,188,798	567	553.4	6.98
40						
41						
42	TOTAL	14,777,494	120,761,369	128,039	115.4	8.17
43						
44						

SALES OF NATURAL GAS BY RATE SCHEDULES - KANSAS OPERATIONS ONLY (FOR ALL COMPANIES)

1. Information called for below shall be given for each rate schedule (by number and title) and each special contract (by name of contracting party).
2. Provide a sub-heading and total for each gas service revenue account.
3. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (e.g. 12 if all are billed monthly).

Line No.	Number and Title of Rate Schedule or Name Holder of Special Contract (a)	MCF. Sold @ F. BTU content (b)	Revenue (c)	Average Number of Customers (d)	MCF of Sales per Customer (e)	Revenue per MCF sold (f)
1	**RESIDENTIAL - A/C 480**					
2						
3						
4	Division 81	10,468,176	125,140,227	113,108	92.6	11.95
5						
6	Division 86	335,928	3,437,782	3,951	85.0	10.23
7						
8						
9	**TOTAL**	10,804,104	128,578,009	117,059	92.3	11.90
10	**COMMERCIAL - A/C 481.1**					
11						
12						
13	Division 81	2,955,547	33,987,189	8,697	339.8	11.50
14						
15	Division 86	256,612	2,487,933	512	501.2	9.70
16						
17						
18	**TOTAL**	3,212,159	36,475,122	9,209	348.8	11.36
19	**INDUSTRIAL, SMALL 481.3**					
20						
21						
22	Division 81	184,363	1,968,507	81	2,276.1	10.68
23						
24	Division 86	-	0	0	0.0	0.00
25						
26						
27						
28	**TOTAL**	184,363	1,968,507	81	2,276.1	10.68
29	**INDUSTRIAL, LARGE 481.4**					
30	NONE	-	0	0	0.0	0.00
31	**TOTAL**	-	0	0	0.0	0.00
32						
33	**IRRIGATION 481.5**					
34	GGS-SW (Southwest Total)	789,528	7,899,249	302	2,614.3	10.01
35	**TOTAL**	789,528	7,899,249	302	2,614.3	10.01
36						
37	**PUBLIC AUTHORITIES 482**	329,450	3,475,744	581	567.0	10.55
38						
39	**TOTAL**	329,450	3,475,744	581	567.0	10.55
40						
41						
42	**TOTAL**	15,319,604	178,396,631	127,232	120.4	11.64
43						
44						

SALES OF NATURAL GAS BY KANSAS COMMUNITIES

1. A similar schedule in the regular report calls for sales of gas by communities of 10,000 population or more by separate states. In the schedule below such information for the state of Kansas is to be listed for all communities served.
2. Communities" mean: Cities, towns, villages and cross-road communities served on other than standard rural rates.

Line No.	COMMUNITY NAME (a)	Population (b)	BTU Content Per CF of Gas (c)	RESIDENTIAL Operating Revenue (d)	MCF (e)	Average No. of Customers per month (f)
1	Subtotal from page 14			120,051,937	10,021,601	108,815
2	Redfield			47,919	3,937	49
3	Savonburg			46,931	3,875	44
4	Scotsman Estates			22,162	1,713	33
5	Sedan			610,662	49,967	643
6	Shawnee			712,313	60,935	499
7	South Haven			135,036	10,889	151
8	Spring Hill			1,230,817	101,535	1,249
9	Stark			31,721	2,539	36
10	Strong City			212,078	17,059	226
11	Sycamore			37,242	3,015	41
12	Tampa			56,566	4,661	63
13	Thayer			6,992	566	8
14	Toronto			148,584	12,011	166
15	Tyro			94,255	7,600	106
16	White City			230,219	18,915	221
17	Wilsey			72,804	5,892	77
18	Yates Center			679,008	56,466	681
19						
20	Total Division 81*			124,427,246	10,383,176	113,108
21						
22	*** Divisions 82, 83, 84, & 85 have**					
23	been collapsed into Division 81					
24						
25						
26						
27	Hickok			25,119	2,342	30
28	Johnson City			675,477	65,825	679
29	Kendall			25,693	2,483	27
30	Manter			65,518	6,160	84
31	Syracuse			666,377	63,668	794
32	Ulysses			2,009,328	193,036	2,337
33	Total Southwest Kansas					
34	Division 86			3,467,512	333,514	3,951
35						
36						
37						
38	PUBLIC AUTHORITY					
39						
40						
41				127,894,758	10,716,690	117,059
42						
43	UNBILLED			683,251	87,414	
44						
45	TOTAL KANSAS			128,578,009	10,804,104	117,059
46						
47						
48						
49						
50						
51						
52						
53						
53						

SALES OF NATURAL GAS BY KANSAS COMMUNITIES

3. If sales by all Kansas Communities are set forth fully in the regular report, the following schedule need not be prepared. In such case, merely make reference to the page in the regular report where sales by Kansas Communities may be found.
4. The information below should be on the same basis as provided in the schedule on page 8 of this supplement except cents may be omitted in reporting revenues, and the totals for the various accounts should agree with the amounts for those accounts shown on page 8.

COMMERCIAL			INDUSTRIAL			TOTAL			
Operating Revenue (g)	MCF (h)	Average No. of Customers per month (i)	Operating Revenue (j)	MCF (k)	Average No. of Customers per month (l)	Operating Revenue (m)	MCF (n)	Average No. of Customers per month (o)	Line No.
32,747,571	2,850,691	8,202	1,968,508	184,364	81	154,768,016	13,056,656	117,098	1
2,645	195	2	0	0	0	50,564	4,132	51	2
9,639	707	8	0	0	0	56,570	4,582	52	3
-	-	0	0	0	0	22,162	1,713	33	4
397,072	33,617	109	0	0	0	1,007,734	83,584	752	5
54,109	4,647	17	0	0	0	766,422	65,582	516	6
18,039	1,292	15	0	0	0	153,075	12,181	166	7
547,432	49,089	122	0	0	0	1,778,249	150,624	1,371	8
15,193	1,122	11	0	0	0	46,914	3,661	47	9
66,619	5,247	32	0	0	0	278,697	22,306	258	10
8,063	571	7	0	0	0	45,305	3,586	48	11
38,242	3,439	14	0	0	0	94,808	8,100	77	12
-	-	0	0	0	0	6,992	566	8	13
18,374	1,361	14	0	0	0	166,958	13,372	180	14
19,341	1,451	14	0	0	0	113,596	9,051	120	15
25,368	1,884	19	0	0	0	255,587	20,799	240	16
6,177	478	4	0	0	0	78,981	6,370	81	17
216,764	17,578	107	0	0	0	895,772	74,044	788	18
									19
34,190,648	2,973,369	8,697	1,968,508	184,364	81	160,586,402	13,540,909	121,886	20
									21
									22
									23
									24
									25
									26
5,851	549	4	12,851	1,279	1	43,821	4,170	35	27
355,400	30,614	96	3,888,970	388,563	161	4,919,847	485,002	936	28
8,227	727	6	1,427	95	1	35,347	3,305	34	29
6,094	485	6	0	0	0	71,612	6,645	90	30
608,187	63,689	105	1,682,339	170,625	41	2,956,903	297,982	940	31
1,690,211	176,576	295	2,313,662	228,966	98	6,013,201	598,578	2,730	32
									33
2,673,970	272,640	512	7,899,249	789,528	302	14,040,731	1,395,682	4,765	34
									35
									36
									37
						3,475,744	329,450	581	38
									39
									40
36,864,618	3,246,009	9,209	9,867,757	973,892	383	178,102,877	15,266,041	127,232	41
									42
(389,496)	(33,850)		(1)	(1)		293,754	53,563		43
									44
36,475,122	3,212,159	9,209	9,867,756	973,891	383	178,396,631	15,319,604	127,232	45
									46
									47
									48
									49
									50
									51
									52
									53
									53

SALES OF NATURAL GAS BY RATE SCHEDULES - KANSAS OPERATIONS ONLY (FOR ALL COMPANIES)

1. Information called for below shall be given for each rate schedule (by number and title) and each special contract (by name of contracting party).
2. Provide a sub-heading and total for each gas service revenue account.
3. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (e.g. 12 if all are billed monthly).

Line No.	Number and Title of Rate Schedule or Name Holder of Special Contract (a)	MCF. Sold @ F. BTU content (b)	Revenue (c)	Average Number of Customers (d)	MCF of Sales per Customer (e)	Revenue per MCF sold (f)
1	**RESIDENTIAL - A/C 480**					
2						
3						
4	Division 81	9,736,885	91,221,472	113,449	85.8	9.37
5						
6	Division 86	343,381	2,149,305	3,993	86.0	6.26
7						
8						
9	**TOTAL**	10,080,266	93,370,777	117,442	85.8	9.26
10	**COMMERCIAL - A/C 481.1**					
11						
12						
13	Division 81	2,755,413	24,324,219	8,825	312.2	8.83
14						
15	Division 86	328,999	1,534,819	512	643.2	4.67
16						
17						
18	**TOTAL**	3,084,412	25,859,038	9,336	330.4	8.38
19	**INDUSTRIAL, SMALL 481.3**					
20						
21						
22	Division 81	164,623	1,344,433	86	1,923.5	8.17
23						
24	Division 86	-	1,224	0	0.0	0.00
25						
26						
27						
28	**TOTAL**	164,623	1,345,657	86	1,923.5	8.17
29	**INDUSTRIAL, LARGE 481.4**					
30	NONE	-	0	0	0.0	0.00
31	**TOTAL**	-	0	0	0.0	0.00
32						
33	**IRRIGATION 481.5**					
34	GGS-SW (Southwest Total)	640,103	1,964,808	280	2,282.7	3.07
35	**TOTAL**	640,103	1,964,808	280	2,282.7	3.07
36						
37	**PUBLIC AUTHORITIES 482**	309,723	2,328,648	577	536.8	7.52
38						
39	**TOTAL**	309,723	2,328,648	577	536.8	7.52
40						
41						
42	**TOTAL**	14,279,127	124,868,928	127,721	111.8	8.74
43						
44						

SALES OF NATURAL GAS BY KANSAS COMMUNITIES

1. A similar schedule in the regular report calls for sales of gas by communities of 10,000 population or more by separate states. In the schedule below such information for the state of Kansas is to be listed for all communities served.
2. Communities" mean: Cities, towns, villages and cross-road communities served on other than standard rural rates.

Line No.	COMMUNITY NAME (a)	Population (b)	BTU Content Per CF of Gas (c)	RESIDENTIAL Operating Revenue (d)	MCF (e)	Average No. of Customers per month (f)
1	Subtotal from page 14			90,427,566	9,426,000	109,148
2	Ramona			35,579	3,757	46
3	Redfield			36,408	3,688	48
4	Savonburg			36,805	3,782	45
5	Scotsman Estates			17,592	1,626	33
6	Sedan			466,453	46,890	633
7	Shawnee			538,029	58,238	507
8	South Haven			104,984	10,478	147
9	Spring Hill			922,201	94,408	1,238
10	Stanley			0	0	-
11	Stark			23,687	2,363	34
12	Strong City			148,847	14,491	226
13	Sycamore			27,925	2,814	40
14	Tampa			41,270	4,170	61
15	Thayer			6,401	634	8
16	Toronto			112,326	11,173	162
17	Tyro			70,280	6,850	105
18	White City			168,911	17,261	218
19	Wilsey			57,924	5,865	78
20	Yates Center			505,618	52,445	671
21						
22	Total Division 81*			93,748,807	9,766,932	113,449
23						
24	* Divisions 82, 83, 84, & 85 have					
25	been collapsed into Division 81					
26						
27						
28						
29	Hickok			17,111	2,665	32
30	Johnson City			423,279	69,159	683
31	Kendall			15,473	2,513	26
32	Manter			42,419	6,292	89
33	Syracuse			430,534	66,533	806
34	Ulysses			1,235,051	191,432	2,356
35	Total Southwest Kansas					
36	Division 86			2,163,868	338,593	3,993
37						
38						
39						
40	PUBLIC AUTHORITY					
41						
42						
43				95,912,675	10,105,525	117,442
44						
45	UNBILLED			(2,541,899)	(25,259)	
46						
47	TOTAL KANSAS			93,370,777	10,080,266	117,442
48						
49						
50						
51						
52						
53						
54						
55						
56						

SALES OF NATURAL GAS BY KANSAS COMMUNITIES

3. If sales by all Kansas Communities are set forth fully in the regular report, the following schedule need not be prepared. In such case, merely make reference to the page in the regular report where sales by Kansas Communities may be found.
4. The information below should be on the same basis as provided in the schedule on page 8 of this supplement except cents may be omitted in reporting revenues, and the totals for the various accounts should agree with the amounts for those accounts shown on page 8.

COMMERCIAL			INDUSTRIAL			TOTAL			
Operating Revenue (g)	MCF (h)	Average No. of Customers per month (i)	Operating Revenue (j)	MCF (k)	Average No. of Customers per month (l)	Operating Revenue (m)	MCF (n)	Average No. of Customers per month (o)	Line No.
23,874,656	2,650,600	8,329	1,343,592	164,622	86	115,645,813	12,241,222	117,563	1
7,582	664	7	0	0	0	43,161	4,421	53	2
2,368	207	2	0	0	0	38,776	3,895	50	3
7,309	586	7	0	0	0	44,114	4,367	52	4
0	0	0	0	0	0	17,592	1,626	33	5
361,244	38,781	107	0	0	0	827,696	85,671	740	6
42,466	4,346	19	0	0	0	580,495	62,584	526	7
15,339	1,251	15	0	0	0	120,323	11,729	161	8
366,735	39,596	124	0	0	0	1,288,936	134,004	1,362	9
0	0		0	0	0	0	0	0	10
12,498	1,138	10	0	0	0	36,185	3,500	44	11
48,087	4,601	32	0	0	0	196,934	19,092	258	12
5,925	469	6	0	0	0	33,850	3,283	46	13
25,189	2,873	14	0	0	0	66,459	7,044	75	14
0	0	0	0	0	0	6,401	634	8	15
14,519	1,174	14	0	0	0	126,846	12,347	176	16
15,945	1,346	14	0	0	0	86,225	8,196	119	17
21,101	1,806	19	0	0	0	190,011	19,067	237	18
5,018	437	4	0	0	0	62,942	6,302	82	19
160,961	15,822	103	0	0	0	666,580	68,267	774	20
									21
24,986,941	2,765,697	8,825	1,343,592	164,622	86	120,079,340	12,697,251	122,359	22
									23
									24
									25
									26
									27
									28
7,194	1,177	4	0	0	0	24,305	3,842	37	29
220,616	46,319	95	997,033	316,399	140	1,640,928	431,876	918	30
5,601	742	6	541	0	1	21,615	3,254	33	31
4,046	452	5	0	0	0	46,465	6,744	94	32
317,923	63,469	105	292,659	97,754	37	1,041,116	227,756	948	33
965,590	204,573	296	676,640	225,950	103	2,877,281	621,956	2,756	34
									35
1,520,970	316,732	512	1,966,873	640,104	280	5,651,711	1,295,429	4,785	36
									37
									38
									39
						2,328,649	309,723	577	40
									41
									42
26,507,911	3,082,429	9,336	3,310,465	804,726	366	128,059,700	14,302,403	127,721	43
									44
(648,873)	1,983					(3,190,772)	(23,276)		45
									46
25,859,038	3,084,412	9,336	3,310,465	804,726	366	124,868,928	14,279,127	127,721	47
									48
									49
									50
									51
									52
									53
									54
									55
									56

SALES OF NATURAL GAS BY RATE SCHEDULES - KANSAS OPERATIONS ONLY (FOR ALL COMPANIES)

1. Information called for below shall be given for each rate schedule (by number and title) and each special contract (by name of contracting party).
2. Provide a sub-heading and total for each gas service revenue account.
3. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (e.g. 12 if all are billed monthly).

Line No.	Number and Title of Rate Schedule or Name Holder of Special Contract (a)	MCF. Sold @ F. BTU content (b)	Revenue (c)	Average Number of Customers (d)	MCF of Sales per Customer (e)	Revenue per MCF sold (f)
1	**RESIDENTIAL - A/C 480**					
2						
3						
4	Division 81	9,779,682	85,327,860	113,791	85.9	8.73
5						
6	Division 86	336,228	2,778,993	3,990	84.3	8.27
7						
8						
9	**TOTAL**	10,115,910	88,106,853	117,781	85.9	8.71
10	**COMMERCIAL - A/C 481.1**					
11						
12						
13	Division 81	2,763,100	22,435,843	8,858	311.9	8.12
14						
15	Division 86	265,945	1,988,737	506	525.6	7.48
16						
17						
18	**TOTAL**	3,029,045	24,424,580	9,364	323.5	8.06
19	**INDUSTRIAL, SMALL 481.3**					
20						
21						
22	Division 81	103,012	751,073	87	1,184.0	7.29
23						
24	Division 86	-	5,352	0	0.0	0.00
25						
26						
27						
28	**TOTAL**	103,012	756,425	87	1,184.0	7.34
29	**INDUSTRIAL, LARGE 481.4**					
30	NONE	-	0	0	0.0	0.00
31	**TOTAL**	-	0	0	0.0	0.00
32						
33	**IRRIGATION 481.5**					
34	GGS-SW (Southwest Total)	714,918	4,231,721	272	2,628.4	5.92
35	**TOTAL**	714,918	4,231,721	272	2,628.4	5.92
36						
37	**PUBLIC AUTHORITIES 482**	293,914	2,191,472	567	518.4	7.46
38						
39	**TOTAL**	293,914	2,191,472	567	518.4	7.46
40						
41						
42	**TOTAL**	14,256,799	119,711,051	128,071	111.3	8.40
43						
44						

SALES OF NATURAL GAS BY KANSAS COMMUNITIES

1. A similar schedule in the regular report calls for sales of gas by communities of 10,000 population or more by separate states. In the schedule below such information for the state of Kansas is to be listed for all communities served.
2. Communities" mean: Cities, towns, villages and cross-road communities served on other than standard rural rates.

	COMMUNITY			RESIDENTIAL		
Line No.	NAME (a)	Population (b)	BTU Content Per CF of Gas (c)	Operating Revenue (d)	MCF (e)	Average No. of Customers per month (f)
1	Subtotal from page 14			83,042,805	9,496,574	109,495
2	Ramona			31,405	3,520	47
3	Redfield			32,540	3,633	47
4	Savonburg			33,042	3,746	45
5	Scotsman Estates			16,164	1,599	33
6	Sedan			425,057	46,998	626
7	Shawnee			496,739	59,701	513
8	South Haven			95,112	10,340	148
9	Spring Hill			840,042	93,377	1,253
10	Stark			21,981	2,448	32
11	Strong City			143,108	15,462	221
12	Sycamore			28,233	3,166	40
13	Tampa			36,617	3,949	61
14	Thayer			4,713	501	8
15	Toronto			95,384	10,253	156
16	Tyro			61,335	6,543	100
17	White City			151,633	16,909	218
18	Wilsey			52,369	5,745	79
19	Yates Center			471,591	53,256	669
20						
21	Total Division 81*			86,079,870	9,837,720	113,791
22						
23	* Divisions 82, 83, 84, & 85 have					
24	been collapsed into Division 81					
25						
26						
27						
28	Hickok			18,775	2,326	30
29	Johnson City			510,502	67,068	687
30	Kendall			21,009	2,797	26
31	Manter			53,086	6,498	89
32	Syracuse			516,564	65,300	804
33	Ulysses			1,551,233	196,571	2,354
34	Total Southwest Kansas					
35	Division 86			2,671,169	340,560	3,990
36						
37						
38						
39	PUBLIC AUTHORITY					
40						
41						
42				88,751,039	10,178,280	117,781
43						
44	UNBILLED			(644,186)	(62,370)	
45						
46	TOTAL KANSAS			88,106,853	10,115,910	117,781
47						
48						
49						
50						
51						
52						
53						
54						
55						

SALES OF NATURAL GAS BY KANSAS COMMUNITIES

3. If sales by all Kansas Communities are set forth fully in the regular report, the following schedule need not be prepared. In such case, merely make reference to the page in the regular report where sales by Kansas Communities may be found.
4. The information below should be on the same basis as provided in the schedule on page 8 of this supplement except cents may be omitted in reporting revenues, and the totals for the various accounts should agree with the amounts for those accounts shown on page 8.

COMMERCIAL			INDUSTRIAL			TOTAL			
Operating Revenue (g)	MCF (h)	Average No. of Customers per month (i)	Operating Revenue (j)	MCF (k)	Average No. of Customers per month (l)	Operating Revenue (m)	MCF (n)	Average No. of Customers per month (o)	Line No.
21,766,093	2,682,459	8,361	756,424	103,013	87	105,565,322	12,282,046	117,943	1
7,336	711	6	0	0	0	38,741	4,231	53	2
2,191	202	2	0	0	0	34,731	3,835	49	3
6,933	593	7	0	0	0	39,975	4,339	52	4
0	0	0	0	0	0	16,164	1,599	33	5
322,333	39,134	108	0	0	0	747,390	86,132	734	6
37,299	4,268	19	0	0	0	534,038	63,969	532	7
14,360	1,211	15	0	0	0	109,472	11,551	163	8
247,301	28,830	126	0	0	0	1,087,343	122,207	1,379	9
12,471	1,266	9	0	0	0	34,452	3,714	41	10
43,113	4,469	31	0	0	0	186,221	19,931	252	11
6,242	512	7	0	0	0	34,475	3,678	47	12
30,267	3,649	14	0	0	0	66,884	7,598	75	13
0	0	0	0	0	0	4,713	501	8	14
13,451	1,143	14	0	0	0	108,835	11,396	170	15
14,608	1,346	13	0	0	0	75,943	7,889	113	16
20,749	1,945	19	0	0	0	172,382	18,854	237	17
5,208	494	5	0	0	0	57,577	6,239	84	18
152,731	16,442	102	0	0	0	624,322	69,698	771	19
									20
22,702,686	2,788,674	8,858	756,424	103,013	87	109,538,980	12,729,407	122,736	21
									22
									23
									24
									25
									26
									27
7,054	911	4	0	0	0	25,829	3,237	34	28
211,058	29,122	93	2,033,140	341,841	131	2,754,700	438,031	911	29
6,278	661	6	3,255	462	1	30,542	3,920	33	30
10,405	1,259	6	0	0	0	63,491	7,757	95	31
463,847	67,997	105	547,879	94,104	34	1,528,290	227,401	943	32
1,259,359	178,969	292	1,647,448	278,510	106	4,458,040	654,050	2,752	33
									34
1,958,001	278,919	506	4,231,722	714,917	272	8,860,892	1,334,396	4,768	35
									36
									37
						2,191,472	293,914	567	38
									39
									40
									41
24,660,687	3,067,593	9,364	4,988,146	817,930	359	120,591,344	14,357,717	127,504	42
									43
(236,107)	(38,548)					(880,293)	(100,918)		44
									45
24,424,580	3,029,045	9,364	4,988,146	817,930	359	119,711,051	14,256,799	127,504	46
									47
									48
									49
									50
									51
									52
									53
									54
									55

Atmos Energy Corporation
Kansas Distribution Systems
Test Year and Pro-forma Income Statements
Twelve Months Ended September 30, 2011, As Adjusted

Line No.	Description	Total [1]	Pro-forma Adjusted with Jurisdictional Allocations Total	Source
	(a)	(b)	(c)	(d)
1	Net Margin	$ 48,876,610	$ 49,532,317	**Section 17**
2				
3	O&M Expense	$ 18,108,292	$ 18,684,894	**WP 9-1**
4	Depreciation Expense	9,725,275	13,347,372	**Section 10**
5	Taxes, Other than Income Taxes	6,515,265	7,238,894	**Section 11**
6	Interest on Customer Deposits	11,995	2,947	**Section 14C**
7	Income Taxes	4,357,057	5,902,984	**Section 11B**
8	Total Expense	$ 38,717,884	$ 45,177,092	**Sum of Lns 3-7**
9				
10	Net Operating Income	$ 10,158,726	$ 4,355,225	**Ln 1-8**
11				
12	Other Income (Expenses)			
13	Other Income (Expenses)	$ (662,091)	$ (662,091)	**WP 9-8**
14	Interest Expense (other than Cust Dep)	5,875,361	5,046,357	**WP 9-8**
15				
16	Net Income	$ 4,945,456	$ (29,041)	**Ln 10-13-14**
17				
18	Note:			
19	1. Data source for amounts shown in Columb (b) is			
20	WP 9-8.			

Atmos Energy Corporation
Kansas Distribution Systems
Operation and Maintenance Expenses
Twelve Months Ended September 30, 2011, As Adjusted

WP 9-1
IS-1 through IS-6; IS 15

Line No.	Acct. No.	Description	Source	Div 79	Div 81	Div 86	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		Production Expenses					
2							
3		B. Natural Gas Production Expenses					
4							
5	B.1	Natural Gas Production & Gathering					
6		Operation					
7	752	Gas Wells Expenses		$ 39,461	$ -	$ -	$ 39,461
8	759	Other Expense		-	-	-	-
9		Total Operation		$ 39,461	$ -	$ -	$ 39,461
10							
11		Maintenance					
12	764	Maintenance of Field Lines		$ -	$ -	$ -	$ -
13	767	Maintenance of Purification equipment		-	-	-	-
14		Total Maintenance		$ -	$ -	$ -	$ -
15							
16	B.2	Products Extraction					
17		Maintenance					
18	784	Maintenance Supervision and Engineering		$ -	$ -	$ -	$ -
19		Total Maintenance		$ -	$ -	$ -	$ -
20							
21	1	Total Production Expenses		$ 39,461	$ -	$ -	$ 39,461
22							
23	2	Natural Gas Storage, Terminaling and Processing Expenses					
24							
25	A.	Underground Storage Expense					
26	814	Operations Supervision and Engineering		$ -	$ -	$ -	$ -
27	815	Maps and Records		-	-	-	-
28	816	Wells Expense		651,328	128	-	651,456
29	818	Compressor Station Expense		-	-	-	-
30	819	Compressor Station Fuel and Power		112,899	-	-	112,899
31	824	Other Expenses		21,090	-	-	21,090
32	825	Storage Well Royalties		61,209	-	-	61,209
33		Total Underground Storage Expense		$ 846,526	$ 128	$ -	$ 846,654
34							
35		Maintenance					
36	830	Maintenance Supervision and Engineering		$ -	$ 174	$ -	$ 174
37	831	Maintenance of structures and improvements		117	-	-	117
38	832	Maintenance of reservoirs and wells		2,292	1,141	-	3,432
39	834	Maintenance of compressor station equipment		15,570	2,719	-	18,289
40	836	Maintenance of Purification equipment		16	-	-	16
41		Total Maintenance		$ 17,995	$ 4,033	$ -	$ 22,028
42							
43	B.	Other Storage Expense					
44		Operation					
45	841	Operation Labor and Expense		$ 27,507	$ 995	$ -	$ 28,502
46	842	Rents		0	-	-	-
47		Total Operation		$ 27,507	$ 995	$ -	$ 28,502
48							
49	2	Total Natural Gas Storage, Terminaling and Processing Expenses		$ 892,029	$ 5,156	$ -	$ 897,185
50							

Atmos Energy Corporation
Kansas Distribution Systems
Operation and Maintenance Expenses
Twelve Months Ended September 30, 2011, As Adjusted

WP 9-1
IS-1 through IS-6; IS 15

Line No.	Acct. No.	Description	Source	Div 79	Div 81	Div 86	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
51	3	Transmission Expense					
52							
53		Operation					
54	850	Operation supervision and engineering		$ -	$ -	$ -	$ -
55	853	Compressor station labor and expenses		-	-	-	-
56	854	Gas for Compressor Station fuel		-	-	-	-
57	856	Mains Expense		-	490	-	490
58	857	Measuring & Regulating Station Equipment		-	3,209	-	3,209
59	860	Rents		-	-	-	-
60	861	Maintenance Supervision and Engineering		11	44	-	55
61		Total Operation		$ 11	$ 3,743	$ -	$ 3,754
62							
63	3	Total Transmission Expenses		$ 11	$ 3,743	$ -	$ 3,754
64							
65	4	Distribution Expenses					
66							
67		Operation					
68	870	Supervision & Engineering		$ (975)	$ 535,117	$ 20,342	$ 554,485
69	871	Load Dispatching & Odorization		-	8,487	-	8,487
70	871.1	Load Dispatching & Odorization - Supervising			16,791	9,166	25,956
71	874	Mains & Service Expenses		7,087	2,806,830	170,880	2,984,797
72	875	Meas. & Reg. Sta. Expenses - General		-	65,461	6,340	71,802
73	877	Meas. & Reg. Sta. Expenses - City Gate		-	791	36	828
74	878	Meter & House Reg. Expenses		-	424,447	24,190	448,638
75	879	Customer Installations Expenses		-	99,026	6,016	105,042
76	880	Other Expenses		-	309,776	15,384	325,159
77	881	Rents		-	76,774	14,349	91,123
78		Total Operation		$ 6,113	$ 4,343,500	$ 266,704	$ 4,616,316
79							
80		Maintenance					
81	885	Supervision & Engineering		$ -	$ 242,085	$ -	$ 242,085
82	886	Structures - Improvements		-	-	8,278	8,278
83	887	Mains		-	142,722	22,696	165,418
84	888	Maintenance of Compressor Station Equipment		-	-	-	-
85	889	Meas. & Reg. Sta. Equip. - General		470	88,471	13,434	102,374
86	890	Maintenance of Meas. & Reg. Sta Equip - Industrial		-	462	-	462
87	892	Services		-	17,595	702	18,297
88	893	Meter & House Regulators		-	4,555	3,438	7,993
89	894	Other Equipment		-	129	-	129
90		Total Maintenance		$ 470	$ 496,019	$ 48,548	$ 545,037
91							
92	4	Total Distribution Expenses		$ 6,582	$ 4,839,519	$ 315,252	$ 5,161,353
93							
94	5	Customer Accounts Expenses					
95							
96		Operation					
97	901	Supervision		$ -	$ 54,396	$ -	$ 54,396
98	902	Meter Reading Expenses		-	768,929	41,349	810,278
99	903	Customer Records & Collection Expenses		-	63,729	5,795	69,524
100	904	Uncollectible Accounts		-	644,650	18,030	662,680
101	905	Misc. Customer Accounts Expenses		-	4,731	3,877	8,608
102		Total Operation		$ -	$ 1,536,435	$ 69,051	$ 1,605,486
103							
104	5	Total Customer Accounts Expenses		$ -	$ 1,536,435	$ 69,051	$ 1,605,486
105							

Atmos Energy Corporation
Kansas Distribution Systems
Operation and Maintenance Expenses
Twelve Months Ended September 30, 2011, As Adjusted

Line No.	Acct. No. (a)	Description (b)	Source (c)	Div 79 (d)	Div 81 (e)	Div 86 (f)	Total (g)	
106	6	Customer Service and Information Expenses						
107								
108		Operation						
109	907	Supervision		$ -	$ 1,065	$ -	$ 1,065	
110	908	Customer Assistance Expenses		-	50	-	50	
111	909	Informational Advertising		-	4,169	682	4,851	
112	910	Miscellaneous Customer Service Expenses		-	429	-	429	
113		Total Operation		$ -	$ 5,713	$ 682	$ 6,395	
114								
115	6	**Total Customer Service and Information Expenses**		$ -	$ 5,713	$ 682	$ 6,395	
116								
117	7	Sales Expense						
118								
119		Sales Expense						
120	911	Supervision		$ -	$ 160	$ -	$ 160	
121	912	Demonstrating and Selling		-	2,232	-	2,232	
122	913	Promotional Advertising Expenses		-	-	-	-	
123	916	Miscellaneous Sales Expenses		-	925	-	925	
124		Total Sales Expense		$ -	$ 3,317	$ -	$ 3,317	
125								
126	7	**Total Sales Expense**		$ -	$ 3,317	$ -	$ 3,317	
127								
128	8	Administrative and General Expenses						
129								
130		Operation						
131	920	Administrative and general salaries		$ -	$ 197,698	$ 34,178	$ 231,876	
132	921	Office Supplies & Expense		-	17,651	709	18,360	
133	922	Administrative Expense Transfer - Credit		297,527	7,765,044	410,100	8,472,671	
134	923	Outside Services		-	3,491	-	3,491	
135	924	Property Insurance		10,118	92,433	6,608	109,159	
136	925	Injuries and Damages		-	10,504	-	10,504	
137	926	Employee Welfare and Pensions		19,285	1,404,708	89,920	1,513,913	
138	928	Regulatory Commission Expense		-	-	-	-	
139	930.2	Miscellaneous General Expense		-	11,373	-	11,373	
140	931	Rents		-	19,366	629	19,995	
141		Total Operation		$ 326,929	$ 9,522,269	$ 542,144	$ 10,391,342	
142								
143	8	**Total Administrative and General Expenses**		$ 326,929	$ 9,522,269	$ 542,144	$ 10,391,342	
144								
145		**Total Operation and Maintenance Expense**		$ 1,265,013	$ 15,916,151	$ 927,129	$ 18,108,293	
146								
147		Allocation of Division 80	**Wp 9-8**				$ -	
148								
149		Adjustments to Operation & Maintenance Expenses						
150		Labor	**Wp 9-2**				$ 212,613	**IS-1**
151		Benefits	**Wp 9-3**				82,670	**IS-2**
152		AGA Dues	**Wp 9-4**				(7,203)	**IS-3**
153		50% of Charitable Contributions	**Wp 9-5**				78,707	**IS-4**
154		Rate Case Expense	**Wp 9-6**				210,000	**IS-5**
155		Expense Report Adjustment	**Wp 9-7**				(69,720)	**IS-6**
156		Pension/Post Retirement Benefits Adjustment	**Wp 9-9**				69,534	**IS-15**
157		Total Adjustments					$ 576,601	
158								
159		Total Adjusted Operation and Maintenance Expenses	Section 3				$ 18,684,894	

Source: See Relied File 6

Atmos Energy Corporation
Detail Trial Balance - Income & Exp Acct per book activity
For the test year 12 Months ended 9/30/11

Line No.	Acct	Acct Desc	Div 002	Div 012	Div 030	Div 080	Div 079	Div 081	Div 086	Grand Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	4030	Depreciation Expense	$ 0	$ 0	$ 0	$ 0	$ 258,211	$ 8,518,847	$ 574,799	$ 9,351,857
2	4060	Amortization of Gas Plant Acquisition					373,418			373,418
3	4074	Regulatory Credits	0				(276)	(5,630)	(318)	(6,224)
4	4081	Taxes other than Income Taxes	0	0	(0)	(0)	535,178	5,629,645	350,442	6,515,265
5	4091	Income taxes, utility operations	22,499,253	4,229,143	1,212,375	307,622	(983,247)	(271,492)	392,293	27,385,947
6	4101	Provision for deferred income taxes	(24,302,704)	(4,012,046)	(2,377,208)			4,846,769		(25,845,189)
7	4114	Investment tax credit adjustment			(3,360)					(3,360)
8	4150	Revenues from Merchandising, Jobing						-		-
9	4160	Costs and expenses of merchandising								-
10	4170	Revenue from Nonutility Operations			(0)		(179)	(3,637)	(206)	(4,021)
11	4190	Interest and Dividend Income	(0)				64	1,311	73	1,448
12	4210	Misc. Nonoperating Income	(0)		(0)	(824,154)	(188)	(742,619)	(217)	(1,567,177)
13	4261	Donations	(6,029)	6,029	0	(0)	5,932	121,613	6,834	134,378
14	4263	Penalties	0				4	75	4	83
15	4264	Civic, Political and Related	(0)		(0)	(0)	1,695	34,588	1,951	38,235
16	4265	Other Deductions	(38,614)	38,614	-	0	3,487	82,350	4,042	89,879
17	4270	Interest on long-term debt	0				182,059	3,753,208	210,068	4,145,334
18	4280	Amortization of debt discount and expense	0				2,423	49,949	2,796	55,168
19	4281	Amortization of loss on reacquired debt	(0)				4,343	89,531	5,011	98,885
20	4300	Interest on debt to associated companies	(0)				688	14,188	794	15,671
21	4310	Other interest expense	(0)				2,516	66,233	3,574	72,323
22	4320	Allowance for borrowed funds used during	247,381	(247,381)			(157)	(44,208)	(440)	(44,805)
23	4800	Residential sales						(80,040,097)	(3,055,322)	(83,095,419)
24	4805	Unbilled Residential Revenue						1,401	(1,308)	92
25	4811	Commercial Revenue-Banner						(20,799,486)	(1,912,896)	(22,712,382)
26	4812	Industrial Revenue-Banner						(651,630)	(8,742)	(660,372)
27	4813	Irrigation Revenue-Banner							(6,137,455)	(6,137,455)
28	4815	Unbilled Comm Revenue						(6,337)	35,929	29,592
29	4820	Other Sales to Public Authority						(1,308,797)	(694,763)	(2,003,561)
30	4825	Unbilled Public Authority Revenue						1,080	889	1,969
31	4870	Forfeited discounts						(316,800)	(29,995)	(346,794)
32	4880	Miscellaneous service revenues						(88,117)	(4,516)	(92,633)
33	4890	Revenues from transporation of						(234)		(234)
34	4895	Revenue-Transportation Commercial						(5,402)	(9,975)	(15,377)
35	4896	Revenue-Transportation Industrial						(3,458,330)	(220,706)	(3,679,036)
36	4950	Other gas revenues						(590,070)	(70,639)	(660,709)
37	7520	Production - Gas well expenses					39,461			39,461
38	7640	Production - Maintenance of field lines								-
39	7670	Production - Maintenance of purification equipment								-
40	8001	Intercompany Gas Well-Head Purchase						(13,034)	(1,816)	(14,850)
41	8010	Natural gas field line purchases						1,059,526	12,478	1,072,004
42	8040	Natural Gas City Gate Purchase						49,701,156	6,827,761	56,528,916
43	8045	Transportation to City Gate								-
44	8050	Other Purchases						(4,908)	-	(4,908)
45	8051	PGA for Residential						46,749,794	1,899,826	48,649,620
46	8052	PGA for Commercial						13,358,358	1,383,007	14,741,365
47	8053	PGA for Industrial						477,436		477,436
48	8054	PGA for Public Authority						918,893	526,016	1,444,909
49	8055	PGA for Irrigation Sales							5,188,901	5,188,901
50	8057	PGA for Transportation Sales							-	-
51	8058	Unbilled PGA Cost						18,360	(25,583)	(7,223)
52	8059	PGA Offset to Unrecovered Gas						(64,288,726)	(7,285,853)	(71,574,578)
53	8060	Exchange Gas - Imbalances						(11,122)	(214)	(11,336)
54	8081	Gas Withdrawn from Storage - Debit						18,060,575		18,060,575
55	8082	Gas Withdrawn from Storage - Credit						(20,077,080)		(20,077,080)
56	8120	Gas Used for Other Utility Operations						(115,341)	(1,629)	(116,971)
57	8130	Other Gas Supply Expenses						700	(0)	700
58	8150	Natural Gas Storage - Maps and records								-
59	8160	Natural gas storage - Wells expense			38,268		651,328	128		689,724
60	8190	Natural gas storage - Compressor station fuel and power					112,899			112,899
61	8210	Natural gas storage - Purification expenses		-						-
62	8240	Natural gas storage - Other expenses			110		21,090			21,200
63	8250	Natural gas storage - Storage wells royalties					61,209			61,209
64	8300	Natural gas storage - Maintenance Supervision and Engineering						174		174
65	8310	Natural gas storage - Maintenance of structures					117			117
66	8320	Natural gas storage - Maintenance of reservoirs and wells			-		2,292	1,141		3,432
67	8340	Natural gas storage - Maintenance of compressor station equipment			-		15,570	2,719		18,289
68	8360	Natural gas storage - Maintenance of purification					16			16
69	8410	Natural gas storage - Operation labor and expenses					27,507	995		28,502
70	8500	Transmission - Operation supervision and engineering								-
71	8510	Transmission - System control and load dispatching	-							-
72	8520	Transmission - Communication system expenses								-
73	8530	Transmission - Compressor station labor and expenses								-
74	8540	Transmission - Gas for compressor station fuel							-	-
75	8560	Transmission - Mains expenses	-					490		490
76	8570	Transmission - Measuring and regulating station expenses						3,209		3,209
77	8580	Transmission - Transmission and compression of gas by others						15,688,954	449,274	16,138,227
78	8600	Transmission - Rents								-
79	8610	Transmission - Maintenance supervision					11	44		55
80	8700	Distribution - Operation Supervision and Engineerin	285,956	27,201	1,989,992	349,511	(975)	535,117	20,342	3,207,144
81	8710	Distribution - Distribution Load Dispatching						8,487		8,487
82	8711	Distribution - Oderization					-	16,791	9,166	25,956
83	8740	Distribution - Mains and Services Expenses	42,359	10,807	76,787	3,450	7,087	2,806,830	170,880	3,118,200
84	8750	Distribution - Measuring and Regulating Station Expenses - General						65,461	6,340	71,802
85	8770	Distribution - Measuring and Regulating Station Exp. - City Gate Chk. Sta.					-	791	36	828
86	8780	Distribution - Meter and House Regulator Expenses			104			424,447	24,190	448,742
87	8790	Distribution - Customer Installations Expenses		-				99,026	6,016	105,042
88	8800	Distribution - Other Expenses	2,232	-	1,769			309,776	15,384	329,161
89	8810	Distribution - Rents	2,934			(461)		76,774	14,349	93,595
90	8850	Distribution - Maintenance Supervision and Engine	-	-	11,293	9,945		242,085	-	263,323
91	8860	Distribution - Maintenance of Structures and Improvements							8,278	8,278
92	8870	Distribution - Maintenance of Mains		201			-	142,722	22,696	165,619
93	8880	Distribution - Maintenance of Compressor Station Equipment								-
94	8890	Distribution - Maint. of Measuring and Regulating Station Equip. - General					470	88,471	13,434	102,374
95	8900	Distribution - Maint. of Measuring and Regulating Station Equip. - Industrial						462		462
96	8920	Distribution - Maintenance of Services						17,595	702	18,297
97	8930	Distribution - Maintenance of Meters and House Regulators						4,555	3,438	7,993
98	8940	Distribution - Maintenance of Other Equipment						129	-	129
99	9010	Customer Accounts - Supervision	-	2,153,876	5,171	5,886		54,396	-	2,219,329

Atmos Energy Corporation
Detail Trial Balance - Income & Exp Acct per book activity
For the test year 12 Months ended 9/30/11

Line No.	Acct	Acct Desc	Div 002	Div 012	Div 030	Div 080	Div 079	Div 081	Div 086	Grand Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
100	9020	Customer Accounts - Meter Reading Expense	45,885	20	1,650		-	768,929	41,349	857,833
101	9030	Customer Accounts - Customer Records and Collec	61,834	12,931,965	2,169,734		-	63,729	5,795	15,233,057
102	9040	Customer Accounts - Uncollectible Accounts						644,650	18,030	662,680
103	9050	Customer Accounts - Miscellaneous Customer Accounts Expense			65			4,731	3,877	8,672
104	9070	Customer Serivce and Informational - Supervision		903	740	-		1,065		2,708
105	9080	Customer Serivce and Informational - Customer Assistance Expenses			86	57,135		50		57,271
106	9090	Customer Serivce and Informational - Informational and Instructional Advertising Expenses			40,610	1,173		4,169	682	46,634
107	9100	Customer Serivce and Informational - Miscellaneous Customer Service		8,964		41,778		429	-	51,171
108	9110	Sales - Supervision			976	173,101		160		174,237
109	9120	Sales - Demonstrating and Selling Expenses	173		14,973	16,571		2,232		33,948
110	9130	Sales - Advertising Expenses			10,339	-				10,339
111	9160	Sales - Miscellaneous Sales Expenses						925		925
112	9200	A&G - Administrative and General Salaries	(6,902,525)	9,441,030	(22,272)	-		197,698	34,178	2,748,110
113	9210	A&G - Office Supplies and Expenses	8,389,857	6,253,995	(59,620)	7,437		17,651	709	14,610,029
114	9220	A&G - Administrative Expenses Transferred - Credi	(65,723,520)	(43,541,646)	(5,343,897)	(1,155,605)	297,527	7,765,044	410,100	(107,291,997)
115	9230	A&G - Outside Services Employed	5,837,447	564,452	126,764	146,935	-	3,491		6,679,089
116	9240	A&G - Property Insurance	225,644	165,119	15,084	27	10,118	92,433	6,608	515,032
117	9250	A&G - Injuries and Damages	7,034,696	99,033	245,714	50,952		10,504		7,440,899
118	9260	A&G - Employee Pensions and Benefits	30,522,248	8,723,963	622,461	158,384	19,285	1,404,708	89,920	41,540,969
119	9270	A&G - Franchise Requirements				2,484				2,484
120	9280	A&G - Regulatory Commission Expenses	17,052		-	97,914				114,966
121	9301	A&G - General Advertising Expenses								-
122	9302	A&G - Miscellaneous General Expense	4,147,977	-	51,925	33,383		11,373		4,244,659
123	9310	A&G - Rents	5,119,554	1,412,682	1,174			19,366	629	6,553,406
124	9320	A&G - Maintenance of General Plant	6,802,496	1,747,437						8,549,933
125										
126	Total		$ (5,688,413)	$ 14,359	$ (1,168,193)	$ (516,532)	$ 1,650,982	$ (7,682,405)	$ (658,703)	$ (14,048,906)

Source: See Relied 1a-g FY 11_TB (By Division)

Atmos Energy Corporation
Analysis of Acct 9220 activity
For the test year 12 Months ended 9/30/11

Line No.	Account	Sub Account	Sub Acct Descrip	Div 2	Div 12	Div 30	Div 79	Div 80	Div 81	Div 86	Grand Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	9220	9341	Admin & General Expenses	$ -	$ -	$ (5,343,897)	$ 51,309	$ 1,786,211	$ 1,045,244	$ 59,051	$ (2,402,082)
2	9220	40001	Billed to West Tex Div	(5,500,068)	(4,084,206)	-	-	-	-	-	(9,584,275)
3	9220	40002	Billed to CO/KS Div	(4,729,586)	(3,348,353)	-	-	-	-	-	(8,077,939)
4	9220	40003	Billed to LA Div	(6,686,494)	(4,724,269)	-	-	-	-	-	(11,410,763)
5	9220	40004	Billed to Mid St Div	(10,076,981)	(6,404,976)	-	-	-	-	-	(16,481,957)
6	9220	40005	Billed to KY Div								-
7	9220	40007	Billed to Nonutilities	(1,913,196)	-	-	-	-	-	-	(1,913,196)
8	9220	40008	Billed to Mid-Tex Div	(24,188,528)	(21,531,344)	-	-	-	-	-	(45,719,872)
9	9220	40009	Billed to MS Div	(5,264,664)	(3,448,498)	-	-	-	-	-	(8,713,162)
10	9220	40010	Billed to Atmos Pipeline Div	(7,364,003)	-	-	-	-	-	-	(7,364,003)
11	9220	41101	Billed from Accounting	-	-	918,651	-	-	-	-	918,651
12	9220	41103	Billed from Cust Service Center	-	-	3,348,353	-	-	-	-	3,348,353
13	9220	41105	Billed from Gas Control	-	-	575,137	-	-	-	-	575,137
14	9220	41106	Billed from Govt Affairs	-	-	91,038	-	-	-	-	91,038
15	9220	41107	Billed from HR	-	-	658,962	-	-	-	-	658,962
16	9220	41108	Billed from HR Other	-	-	975,500	-	-	-	-	975,500
17	9220	41109	Billed from IT	-	-	1,301,460	-	-	-	-	1,301,460
18	9220	41111	Billed from Pipeline Gas Control								-
19	9220	41112	Billed from Investor Relations	-	-	231,314	-	-	-	-	231,314
20	9220	41113	Billed from Legal	-	-	291,334	-	-	-	-	291,334
21	9220	41114	Billed from Corp Secretary	-	-	255,049	-	-	-	-	255,049
22	9220	41115	Billed from Planning & Budget	-	-	56,966	-	-	-	-	56,966
23	9220	41116	Billed from Rates	-	-	193,789	-	-	-	-	193,789
24	9220	41117	Billed from Purchasing	-	-	141,153	-	-	-	-	141,153
25	9220	41119	Billed from Treasury	-	-	105,342	-	-	-	-	105,342
26	9220	41120	Billed from Risk Mgmt	-	-	840,857	-	-	-	-	840,857
27	9220	41121	Billed from Management Committee	-	-	782,285	-	-	-	-	782,285
28	9220	41122	Billed from Allocations & Other	-	-	(229)	-	-	-	-	(229)
29	9220	41123	Billing for Overhead Capitalized	-	-	(2,689,023)	-	-	-	-	(2,689,023)
30	9220	41125	Billed from Customer Service Initiative								-
31	9220	41127	Billed from Utility Marketing Council								-
32	9220	41131	Billing for CSC O&M	-	-	(3,348,353)	-	-	1,703,938	67,676	(1,576,739)
33	9220	41132	Billing for SS O&M	-	-	(4,729,586)	246,218	(2,941,815)	5,015,862	283,373	(2,125,949)
34	9220	41133	Billed from Non Call Center Customer Se	-	-	-	-	-	-	-	-
35											
36	Total			$ (65,723,520)	$ (43,541,646)	$ (5,343,897)	$ 297,527	$ (1,155,605)	$ 7,765,044	$ 410,100	$ (107,291,997)

Source: See Relied 1m - Acct 9220 Activity

WP 9-2
IS-1

Atmos Energy Corporation
Kansas Jurisdiction
Labor Adjustment
For the test period 12 months ended September 30, 2011

Line No.	Description	Liberty Div 79	Kansas Div 81	Southwest Div 86	Total Direct Kansas	Admin & General Offices: Shared Srvc Gen Office Div 02	Shared Srvc Cust Support Div 12	COKS Gen Office Div 30	Kansas Admin Div 80	Total (e thru i)	Source
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Computation of Labor Expense Adjustment										
1	Gross Labor - test year (before allocations)	$ 56,620	$ 7,879,509	$ 333,506	$ 8,269,636	$ 33,837,752	$ 25,807,500	$ 2,661,521	$ 704,001	$ 71,280,410	**WP 9-2-1**
2	% Budgeted Merit Increase	3.00%	3.00%	3.00%		3.00%	3.00%	3.00%	3.00%		**FY12 Budget**
3											
4	Gross Labor w/ Annualized Merit Incr.	$ 58,319	$ 8,115,894	$ 343,512	$ 8,517,725	$ 34,852,884	$ 26,581,725	$ 2,741,366	$ 725,121	$ 73,418,822	
5	Amount of Increase	1,699	236,385	10,005	248,089	1,015,133	774,225	79,846	21,120	2,138,412	
6	Allocation to Kansas	100.00%	100.00%	100.00%		4.07%	4.17%	58.24%	100.00%		**Section 12**
7											
8	Increase Allocated to Kansas	$ 1,699	$ 236,385	$ 10,005	$ 248,089	$ 41,316	$ 32,285	$ 46,502	$ 21,120	$ 389,312	
9	3 Yr Average Expense Rate	54.61%	54.61%	54.61%	54.61%	54.61%	54.61%	54.61%	54.61%		**WP 9-2-2**
10											
11	**Labor Expense Increase**	$ 928	$ 129,096	$ 5,464	$ 135,488	$ 22,564	$ 17,632	$ 25,396	$ 11,534	$ 212,613	
12											
13	**Allocations:**										
14											
15	Atmos Shared Services - General Office Div 02 (a)				$ 22,564	$ (22,564)				$ -	
16	Atmos Shared Services - Customer Support Div 12 (b)				17,632		$ (17,632)			-	
17	CO/KS Business Unit General Office Div 30 (a)				25,396			$ (25,396)		-	
18	Kansas Admin Div 80 (a)				11,534				$ (11,534)	-	
19	Total KS jurisdictional Labor Expense Adjustment				$ 212,613	$ -	$ -	$ -	$ -	$ 212,613	**IS-1**
20											
21	(a) Allocations - Composite										
22	(b) Allocations - Customers										

Atmos Energy Corporation
G/L Labor Analysis - Sub Accts 01000, 01001, 01003, 01006, 01008, 01009
For the test period 12 months ended September 30, 2011

line	Acct Desc	Sub Account	DIV 79	DIV 81	DIV 86	DIV 2	DIV 12	DIV 30	DIV 80	Grand Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	**Summary**									
2	Capitalized Labor: CWIP and subs	01001, 03, 09	$ 4,359	$ 4,145,397	$ 98,397	$ 9,873,282	$ 5,043,157	$ 1,479,166	$ 289,666	$ 20,933,423
3	Undistributed Stores 1630		-	-	-	247,193	-	62,263	(2,382)	307,074
4	Below the Line 4264, 4265		-	-	-	251,753	-	-	-	251,753
5	O&M Labor Expense	01000, 06, 08	52,262	3,734,112	235,109	23,465,524	20,764,344	1,120,092	416,717	49,788,160
6	**Total Gross Labor - 01000, 01, 03, 06, 08, 09**		$ 56,620	$ 7,879,509	$ 333,506	$ 33,837,752	$25,807,500	$ 2,661,521	$ 704,001	$ 71,280,410
7										
8	Above amts includes the following reclassification:									
9	SSU labor expense to capital					8,338,753	3,318,640			
10										
11										
12										
13			DIV	DIV	DIV	DIV	DIV	DIV	DIV	
14	Acct Desc	Sub Account	79	81	86	2	12	30	80	Grand Total
15										
16	**Detail**									
17	CWIP 1070	1000	$ -	$ -	$ -	$ 74,587	$ -	$ -	$ -	$ 74,587
18	CWIP 1070	1001	-	-	-			-	-	-
19	CWIP 1070	1009	835	76,182	1,816	29,990	163,347	164,599	88,238	525,006
20	Undistributed Stores 1630	1000				246,996		59,821		306,817
21	Undistributed Stores 1630	1008				196		2,442	(2,382)	257
22	Below the Line 4264	1000				250,671				250,671
23	Below the Line 4264	1008				1,083				1,083
24	Below the Line 4265	1000								-
25	Below the Line 4265	1008								-
26	O&M expense 7010-9320	1000	52,866	3,158,524	234,944	31,496,740	24,053,526	1,122,601	412,099	60,531,300
27	O&M expense 7010-9320	1001	3,524	4,069,215	96,581	1,504,538	1,561,170	1,314,567	201,428	8,751,023
28	O&M expense 7010-9320	1003								-
29	O&M expense 7010-9320	1006		551,794		33,723		85		585,602
30	O&M expense 7010-9320	1008	(604)	23,794	165	199,227	29,458	(2,595)	4,619	254,065
31	O&M expense 7010-9320	1009								-
32	**Total Gross Labor - 01000, 01, 03, 06, 08, 09**		$ 56,620	$ 7,879,509	$ 333,506	$ 33,837,752	$25,807,500	$ 2,661,521	$ 704,001	$ 71,280,410
33										
34	**Source: See Relied File 1i - 11 Labor Sub Accts**									

Atmos Energy Corporation
Three year average labor expense rate - Kansas Jurisdictional:
Labor sub accts 01000, 01001, 01003, 01006, 01008, 01009

Line	(a)	(b) DIV 79	(c) DIV 81	(d) DIV 86	(e) DIV 2	(f) DIV 12	(g) DIV 30	(h) DIV 80	(i) Total	(j) % Exp	Source
	12 mths Sep09										
1	O&M Labor Expense	$ 12,417	$ 3,736,618	$ 210,443	$ 30,806,230	$ 15,462,504	$ 1,253,388	$ 423,879	$ 51,905,479		WP 9-2-4, Ln 5
2	Gross Labor	$ 12,417	$ 7,185,133	$ 295,439	$ 40,702,297	$ 18,337,839	$ 2,261,165	$ 791,032	$ 69,585,323		WP 9-2-4, Ln 6
3											
4	FY10 allocation	100.00%	100.00%	100.00%	3.68%	4.07%	54.38%	100.00%			
5											
6	KS Juris exp	$ 12,417	$ 3,736,618	$ 210,443	$ 1,133,669	$ 629,324	$ 681,592	$ 423,879	$ 6,827,942	58.07%	
7	KS Juris gross labor	$ 12,417	$ 7,185,133	$ 295,439	$ 1,497,845	$ 746,350	$ 1,229,622	$ 791,032	$ 11,757,837		
8											
9	**12 mths Sep10**										
10	O&M Labor Expense	$ 54,063	$ 3,662,087	$ 239,867	$ 24,580,652	$ 16,669,167	$ 1,188,733	$ 347,817	$ 46,742,387		WP 9-2-3, Ln 4
11	Gross Labor	$ 54,664	$ 7,837,504	$ 336,603	$ 34,821,602	$ 19,255,489	$ 2,571,237	$ 700,051	$ 65,577,150		WP 9-2-3, Ln 5
12											
13	FY11 allocation	100.00%	100.00%	100.00%	3.77%	4.07%	55.05%	100.00%			
14											
15	KS Juris exp	$ 54,063	$ 3,662,087	$ 239,867	$ 925,605	$ 678,555	$ 654,426	$ 347,817	$ 6,562,421	52.76%	
16	KS Juris gross labor	$ 54,664	$ 7,837,504	$ 336,603	$ 1,311,237	$ 783,837	$ 1,415,528	$ 700,051	$ 12,439,424		
17											
18	**12 mths Sep11**										
19	O&M Labor Expense	$ 52,262	$ 3,734,112	$ 235,109	$ 23,465,524	$ 20,764,344	$ 1,120,092	$ 416,717	$ 49,788,160		WP 9-2-1, Ln 5
20	Gross Labor	$ 56,620	$ 7,879,509	$ 333,506	$ 33,837,752	$ 25,807,500	$ 2,661,521	$ 704,001	$ 71,280,410		WP 9-2-1, Ln 6
21											
22	FY12 allocation (Sect 12)	100.00%	100.00%	100.00%	4.07%	4.17%	58.24%	100.00%			Section 12 Allocation
23											
24	KS Juris exp	$ 52,262	$ 3,734,112	$ 235,109	$ 955,047	$ 865,873	$ 652,341	$ 416,717	$ 6,911,462	53.26%	
25	KS Juris gross labor	$ 56,620	$ 7,879,509	$ 333,506	$ 1,377,197	$ 1,076,173	$ 1,550,070	$ 704,001	$ 12,977,076		
26											
27	**3 Yr Average Kansas Jurisdictional Expense rate**										
28	O&M Labor Expense	$ 39,581	$ 3,710,939	$ 228,473	$ 1,004,774	$ 724,584	$ 662,787	$ 396,138	$ 6,767,275	**54.61%**	
29	Gross Labor	$ 41,234	$ 7,634,048	$ 321,849	$ 1,395,426	$ 868,787	$ 1,398,406	$ 731,695	$ 12,391,445		
30		96%	48.61%	70.99%	72.00%	83.40%	47.40%	54.14%			

Atmos Energy Corporation
G/L Labor Analysis - Sub Accts 01000, 01001, 01003, 01006, 01008, 01009
For the test period 12 months ended Sept 30, 2010

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Div	Div	Div	Div	Div	Div	Div	
Line	Acct Desc	SubAcct	79	81	86	2	12	30	80	Grand Total
	Summary									
1	Capitalized Labor: CWIP and subs	01001, 03, 09	$ 601	$ 4,175,417	$ 96,736	$ 9,820,802	$ 2,586,322	$ 43,402	$ 282,508	$ 17,005,788
2	Undistributed Stores 1630		-	-	-	236,829	-	-	69,726	306,554
3	Below the Line 4264, 4265		-	-	-	183,319	-	1,339,102	-	1,522,421
4	O&M Labor Expense	01000, 06, 08	54,063	3,662,087	239,867	24,580,652	16,669,167	1,188,733	347,817	46,742,387
5	**Total Gross Labor - 01000, 01, 03, 06, 08, 09**		$ 54,664	$ 7,837,504	$ 336,603	$ 34,821,602	$ 19,255,489	$ 2,571,237	$ 700,051	$ 65,577,150
6										
7	Above amts includes the following reclassification:									
8	SSU labor expense to capital					$ 8,097,693	$ 2,428,429			
9										
10										
11										
12			Div	Div	Div	Div	Div	Div	Div	
13	Acct Desc	SubAcct	79	81	86	2	12	30	80	Grand Total
14	**Detail**									
15	CWIP 1070	1000	$ -	$ -	$ -	$ 74,587	$ -	$ -	$ -	$ 74,587
16	CWIP 1070	1009		91,997	1,948	39,856	14,236	42,997	48,300	239,334
17	Undistributed Stores 1630	1000				233,000			69,430	302,429
18	Undistributed Stores 1630	1008				3,829			296	4,125
19	Below the Line 4264	1000				179,544				179,544
20	Below the Line 4264	1008				3,774				3,774
21	Below the Line 4265	1000								-
22	Below the Line 4265	1008						1,339,102		1,339,102
23	O&M expense 7010-9320	1000	53,809	3,219,576	236,813	32,717,908	18,907,870	1,182,968	347,756	56,666,699
24	O&M expense 7010-9320	1001	601	4,083,420	94,788	1,608,666	143,657		234,208	6,165,339
25	O&M expense 7010-9320	1003						405		405
26	O&M expense 7010-9320	1006		431,554		591		5,765		437,910
27	O&M expense 7010-9320	1008	254	10,957	3,055	(40,155)	189,727		61	163,899
28	O&M expense 7010-9320	1009								-
29	**Total Gross Labor - 01000, 01, 03, 06, 08, 09**		$ 54,664	$ 7,837,504	$ 336,603	$ 34,821,602	$ 19,255,489	$ 2,571,237	$ 700,051	$ 65,577,150
30										
31	**Source: See Relied File 1h - 10 Labor Sub Accts**									

Atmos Energy Corporation
G/L Labor Analysis - Sub Accts 01000, 01001, 01003, 01006, 01008, 01009
For the test period 12 months ended Sept 30, 2009

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line	Acct Desc	SubAcct	79	81	86	2	12	30	80	Grand Total
1	**Summary**									
2	Capitalized Labor: CWIP and subs	01001, 03, 09	$ -	$ 3,448,515	$ 84,996	$ 9,572,462	$ 2,875,335	$ 1,008,631	$ 298,389	$ 17,288,327
3	Undistributed Stores 1630		-	-	-	164,851	-	-	68,764	233,615
4	Below the Line 4264, 4265		-	-	-	158,754	-	(853)	-	157,901
5	O&M Labor Expense	01000, 06, 08	12,417	3,736,618	210,443	30,806,230	15,462,504	1,253,388	423,879	51,905,479
6	**Total Gross Labor - 01000, 01, 03, 06, 08, 09**		$ 12,417	$ 7,185,133	$ 295,439	$ 40,702,297	$ 18,337,839	$ 2,261,165	$ 791,032	$ 69,585,323
7										
8	Above amts includes the following reclassification:									
9	SSU labor expense to capital					$ 8,082,138	$ 2,703,657			
10										
11	Acct Desc	SubAcct	79	81	86	2	12	30	80	Grand Total
12	**Detail**									
13	CWIP 1070	1009	$ -	$ 36,061	$ 1,564	$ 27,898	$ 241	$ 11,830	$ 9,116	$ 86,709
14	Undistributed Stores 1630	1000		-	-	164,402	-	-	67,577	231,979
15	Undistributed Stores 1630	1008		-	-	450	-	-	1,187	1,636
16	Below the Line 4264	1000		-	-	158,062	-	-	-	158,062
17	Below the Line 4264	1008		-	-	692	-	-	-	692
18	Below the Line 4265	1000		-	-	-	-	(783)	-	(783)
19	Below the Line 4265	1008		-	-	-	-	(70)	-	(70)
20	O&M expense 7010-9320	1000	10,699	3,191,431	211,831	38,646,619	18,069,854	1,240,189	424,144	61,794,767
21	O&M expense 7010-9320	1001	-	3,412,454	83,432	1,462,426	171,437	996,801	289,273	6,415,823
22	O&M expense 7010-9320	1003	-	-	-	-	-	-	-	-
23	O&M expense 7010-9320	1006	-	543,928	-	379	0	17,094	(1,114)	560,286
24	O&M expense 7010-9320	1008	1,718	1,259	(1,388)	241,371	96,307	(3,894)	849	336,221
25	O&M expense 7010-9320	1009	-	-	-	-	-	-	-	-
26	**Total Gross Labor - 01000, 01, 03, 06, 08, 09**		$ 12,417	$ 7,185,133	$ 295,439	$ 40,702,297	$ 18,337,839	$ 2,261,165	$ 791,032	$ 69,585,323

Source: See Relied File 1o - 09 Labor Sub Accts

Atmos SSU Gross Labor Exp recapitalization - Used for the determination of Gross Labor Exp/Cap Percents
For O&M Exp Accts (701-932) with Gross labor subs 01000,01001,01003,01006,01008,01009

Twelve Months Ended 9/30/11

Line	Div	CC	Tot O&M Exp	O&M Cap	Gross O&M Labor	SSU O/H Cap Rate	Exp Adj Add to Cap	Adjusted Expense
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	2	1001	$ 832,062	$ -	$ 832,062	58.49%	$ (486,711)	$ 345,352
2	2	1101	457,000		457,000	58.49%	(267,320)	189,680
3	2	1106	155,504		155,504	59.08%	(91,876)	63,629
4	2	1107	393,250		393,250	58.49%	(230,030)	163,220
5	2	1108	457,893		457,893	80.00%	(366,314)	91,579
6	2	1110	89,148		89,148	49.25%	(43,903)	45,246
7	2	1111	301,039		301,039	56.41%	(169,828)	131,211
8	2	1112	21,123		21,123	15.21%	(3,212)	17,910
9	2	1114	223,852		223,852	24.97%	(55,894)	167,958
10	2	1116	183,914		183,914	5.70%	(10,483)	173,431
11	2	1117	125,319		125,319	49.68%	(62,253)	63,066
12	2	1118	214,819		214,819	40.26%	(86,489)	128,330
13	2	1119	549,046	1,793	550,839	58.49%	(321,162)	227,884
14	2	1120	537,939		537,939	16.54%	(88,957)	448,982
15	2	1121	489,915		489,915	90.00%	(440,923)	48,991
16	2	1123	272,744	8,984	281,728	0.00%	-	272,744
17	2	1125	713,419	2,361	715,779	0.00%	-	713,419
18	2	1126	516,330	188	516,517	58.49%	(302,024)	214,305
19	2	1128	1,043,135	20,026	1,063,161	6.88%	(71,716)	971,419
20	2	1129	428,793		428,793	2.00%	(8,576)	420,217
21	2	1130	465,043		465,043	53.12%	(247,038)	218,005
22	2	1132	372,354		372,354	0.00%	-	372,354
23	2	1133	673,076	1,879	674,955	0.00%	-	673,076
24	2	1134	1,098,220	55,470	1,153,691	46.43%	(509,902)	588,318
25	2	1135	1,695,276	508,571	2,203,847	11.50%	(194,957)	1,500,319
26	2	1137	1,808,777	115,586	1,924,363	26.96%	(487,583)	1,321,194
27	2	1139	245,609	22,147	267,756	36.84%	(90,487)	155,121
28	2	1141	424,553		424,553	0.00%	-	424,553
29	2	1144	731,828	13,234	745,062	0.00%	-	731,828
30	2	1145	310,432	9,970	320,402	0.00%	-	310,432
31	2	1146	615,688	498,102	1,113,790	46.32%	(285,161)	330,527
32	2	1150	344,750		344,750	53.57%	(184,687)	160,062
33	2	1153	63,692		63,692	0.00%	-	63,692
34	2	1154	1,613,120	5,876	1,618,997	60.86%	(981,675)	631,445
35	2	1155		909	909	0.00%	-	-
36	12	1156	796,106	347,597	1,143,703	25.00%	(199,027)	597,080
37	12	1158	357,513	62,349	419,862	5.47%	(19,551)	337,962
38	2	1159	85,988		85,988	0.00%	-	85,988
39	2	1161	238,128		238,128	58.49%	(139,292)	98,836
40	2	1165	439,506	116,873	556,379	14.00%	(61,531)	377,975
41	2	1171	243,071		243,071	60.86%	(147,922)	95,149
42	2	1201	752,877		752,877	58.49%	(440,392)	312,485
43	12	1203	6,179,890	32,234	6,212,123	15.50%	(957,846)	5,222,043
44	2	1209	159,146		159,146	0.00%	-	159,146
45	12	1210	8,430,578	105,989	8,536,567	15.50%	(1,306,690)	7,123,888
46	12	1213	1,355,287	84,969	1,440,256	0.00%	-	1,355,287
47	12	1214	416,818		416,818	0.00%	-	416,818
48	12	1215	2,353,494	65,272	2,418,766	15.50%	(364,778)	1,988,717
49	12	1225	139,732	16,866	156,598	73.94%	(103,323)	36,409
50	12	1226	767,015	12,300	779,316	0.00%	-	767,015
51	12	1227	894,578	669,626	1,564,204	41.07%	(367,425)	527,153
52	12	1228	2,309,972	163,969	2,473,941	0.00%	-	2,309,972
53	2	1401	629,253	31,684	660,937	0.00%	-	629,253
54	2	1403	515,684		515,684	58.49%	(301,647)	214,037
55	2	1405	760,287	17,478	777,766	0.00%	-	760,287
56	2	1407	450,996		450,996	36.00%	(162,359)	288,637
57	2	1408	974,070	25,221	999,292	0.00%	-	974,070
58	2	1410	65,365		65,365	0.00%	-	65,365
59	2	1414	752,600		752,600	0.00%	-	752,600
60	2	1415	170,489		170,489	0.00%	-	170,489
61	2	1501	1,907,448		1,907,448	41.87%	(798,639)	1,108,809
62	2	1502	122,764		122,764	0.00%	-	122,764
63	2	1503	307,441		307,441	0.00%	-	307,441
64	2	1504	76,132		76,132	58.49%	(44,533)	31,599
65	2	1505	127,307		127,307	0.00%	-	127,307
66	2	1508	299,811		299,811	0.00%	-	299,811
67	2	1821	276,895		276,895	0.00%	-	276,895
68	2	1822	146,698		146,698	0.00%	-	146,698
69	2	1823	316,789		316,789	0.00%	-	316,789
70	2	1825	223,677		223,677	0.00%	-	223,677
71	2	1826	46,560		46,560	0.00%	-	46,560
72	2	1827	218,877		218,877	0.00%	-	218,877
73	2	1828	86,771		86,771	0.00%	-	86,771
74	2	1831	94,046		94,046	0.00%	-	94,046
75	2	1833	89,205		89,205	0.00%	-	89,205
76	2	1835	675,531		675,531	0.00%	-	675,531
77	2	1836	222,529		222,529	0.00%	-	222,529
78	2	1837	669,681	48,186	717,866	0.00%	-	669,681
79	2	1838	421,726		421,726	0.00%	-	421,726
80	2	1839	194,829		194,829	0.00%	-	194,829
81	2	1901	188,262		188,262	0.00%	-	188,262
82	12	1901	82,001		82,001	0.00%	-	82,001
83	2	1913	310,589		310,589	49.35%	(153,278)	157,311
84			$ 55,812,674	$ 3,065,708	58,878,382		$ (11,657,394)	$ 44,155,281
85								
86			Breakout for Div 12 & Div 2:					
87		Div 12	$ 24,082,984		$ 25,644,154		$ (3,318,640)	$ 20,764,344
88							-13.78%	Div 12 % Capitalized Overhead
89								
90		Div 02	$ 31,729,690		$ 33,234,228		$ (8,338,753)	$ 23,390,937
91							-26.28%	Div 02 % Capitalized Overhead

Atmos SSU Gross Labor Exp recapitalization - Used for the determination of Gross Labor Exp/Cap Percents
For O&M Exp Accts (701-932) with Gross labor subs 01000,01001,01003,01006,01008,01009

Twelve Months Ended 9/30/10

Line	Div	CC	Tot O&M Exp	O&M Cap	Gross O&M Labor	SSU O/H Cap Rate	Exp Adj Add to Cap	Adjusted Expense
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
92	2	1001	$ 955,527	$ -	$ 955,527	56.58%	$ (540,609)	$ 414,918
93	2	1101	441,350		441,350	56.58%	(249,703)	191,647
94	2	1106	304,628		304,628	58.24%	(177,419)	127,209
95	2	1107	508,941		508,941	56.58%	(287,944)	220,997
96	2	1108	251,341		251,341	80.00%	(201,073)	50,268
97	2	1109	(19,285)	97	(19,189)	0.00%	-	(19,285)
98	12	1109	526,952	66	527,018	0.00%	-	526,952
99	2	1110	91,100		91,100	49.88%	(45,444)	45,656
100	2	1111	290,991		290,991	60.70%	(176,632)	114,360
101	2	1114	222,948		222,948	23.44%	(52,269)	170,679
102	2	1115	(78,357)	(121)	(78,478)	0.00%	-	(78,357)
103	12	1115	2,055,417	364	2,055,781	0.00%	-	2,055,417
104	2	1116	178,557		178,557	3.59%	(6,412)	172,145
105	2	1117	148,376		148,376	47.81%	(70,933)	77,443
106	2	1118	205,929		205,929	40.26%	(82,910)	123,019
107	2	1119	507,515		507,515	56.58%	(287,137)	220,378
108	2	1120	528,253		528,253	14.98%	(79,137)	449,117
109	2	1121	414,171		414,171	89.96%	(372,603)	41,568
110	2	1123	337,477	5,891	343,367	0.00%	-	337,477
111	2	1125	714,656	1,952	716,608	0.00%	-	714,656
112	2	1126	521,861		521,861	56.58%	(295,253)	226,608
113	2	1128	1,051,985		1,051,985	4.10%	(43,087)	1,008,898
114	2	1129	389,495		389,495	2.00%	(7,790)	381,705
115	2	1130	450,136		450,136	53.18%	(239,368)	210,768
116	2	1132	376,214		376,214	0.00%	-	376,214
117	2	1133	645,216		645,216	0.00%	-	645,216
118	2	1134	1,134,627		1,134,627	41.43%	(470,060)	664,567
119	2	1135	1,500,013	264,011	1,764,025	11.50%	(172,502)	1,327,512
120	2	1137	1,437,286	62,785	1,500,070	26.15%	(375,905)	1,061,380
121	2	1139	254,931	17,500	272,431	36.84%	(93,922)	161,009
122	2	1141	380,475	4,822	385,297	0.00%	-	380,475
123	2	1144	713,964	3,197	717,161	0.00%	-	713,964
124	2	1145	276,831	546	277,376	0.00%	-	276,831
125	2	1146	691,124	440,295	1,131,419	53.85%	(372,144)	318,980
126	2	1148	(20,234)	(27)	(20,261)	0.00%	-	(20,234)
127	12	1148	899,150	2,850	902,000	0.00%	-	899,150
128	2	1150	334,042		334,042	52.99%	(177,006)	157,036
129	2	1153	22,596	4,613	27,210	0.00%	-	22,596
130	2	1154	1,663,657		1,663,657	57.51%	(956,799)	706,858
131	2	1155	25,500	7,003	32,504	0.00%	-	25,500
132	2	1156	993,843	262,738	1,256,581	13.33%	(132,512)	861,331
133	12	1158	527,815	23,118	550,933	5.47%	(28,865)	498,950
134	2	1159	174,359		174,359	0.00%	-	174,359
135	2	1161	230,566		230,566	56.58%	(130,447)	100,119
136	2	1165	226,666	145,551	372,217	14.00%	(31,733)	194,933
137	2	1166	744,946	217,987	962,932	0.00%	-	744,946
138	2	1167	(4,516)		(4,516)	0.00%	-	(4,516)
139	2	1168	(4,227)		(4,227)	0.00%	-	(4,227)
140	2	1171	229,176		229,176	57.51%	(131,803)	97,373
141	2	1200	(28,995)		(28,995)	0.00%	-	(28,995)
142	12	1200	1,049,914		1,049,914	0.00%	-	1,049,914
143	2	1201	547,902		547,902	56.58%	(309,986)	237,915
144	12	1203	3,504,294	808	3,505,102	18.93%	(663,284)	2,841,010
145	2	1209	153,770		153,770	0.00%	-	153,770
146	12	1210	5,422,744	544	5,423,289	17.65%	(957,346)	4,465,399
147	12	1213	1,350,016	33	1,350,048	0.00%	-	1,350,016
148	12	1214	366,349		366,349	0.00%	-	366,349
149	2	1215	1,331,927	4,216	1,336,143	18.20%	(242,411)	1,089,517
150	12	1215	705,529		705,529	18.20%	(128,406)	577,123
151	12	1225	156,670		156,670	59.66%	(93,468)	63,202
152	12	1226	892,935		892,935	0.00%	-	892,935
153	12	1227	1,475,346	115,872	1,591,218	37.76%	(557,060)	918,285
154	12	1228	111,625		111,625	0.00%	-	111,625
155	2	1350	87,699		87,699	0.00%	-	87,699
156	2	1401	444,874	3,419	448,294	0.00%	-	444,874
157	2	1402	-	169	169	0.00%	-	-
158	2	1403	505,268		505,268	56.58%	(285,866)	219,402
159	2	1405	701,511	10,774	712,285	0.00%	-	701,511
160	2	1407	236,430		236,430	33.02%	(78,074)	158,356
161	2	1408	998,468		998,468	0.00%	-	998,468
162	2	1410	264,279		264,279	0.00%	-	264,279
163	2	1414	694,906		694,906	0.00%	-	694,906
164	2	1415	122,648		122,648	0.00%	-	122,648
165	2	1501	1,799,783		1,799,783	40.75%	(733,490)	1,066,293
166	2	1502	119,224		119,224	0.00%	-	119,224
167	2	1503	329,588		329,588	0.00%	-	329,588
168	2	1504	73,898		73,898	56.81%	(41,982)	31,917
169	2	1505	166,941		166,941	0.00%	-	166,941
170	2	1821	162,907	4,962	167,869	0.00%	-	162,907
171	2	1822	68,871		68,871	0.00%	-	68,871
172	2	1823	235,758	33,718	269,476	0.00%	-	235,758
173	2	1825	217,721		217,721	0.00%	-	217,721
174	2	1826	111,691	479	112,170	0.00%	-	111,691
175	2	1827	219,136		219,136	0.00%	-	219,136
176	2	1828	58,884	1,563	60,446	0.00%	-	58,884
177	2	1829	14,592		14,592	0.00%	-	14,592
178	2	1831	116,047		116,047	0.00%	-	116,047
179	2	1832	7,858		7,858	0.00%	-	7,858
180	2	1833	84,948	1,659	86,607	0.00%	-	84,948
181	2	1835	642,600		642,600	0.00%	-	642,600
182	2	1836	229,008		229,008	0.00%	-	229,008
183	2	1837	572,501	82,527	655,029	0.00%	-	572,501
184	2	1838	362,337	26,341	388,679	0.00%	-	362,337
185	2	1839	175,579		175,579	0.00%	-	175,579
186	2	1901	107,327		107,327	0.00%	-	107,327
187	12	1901	52,840		52,840	0.00%	-	52,840
188	2	1913	295,809		295,809	49.13%	(145,330)	150,478
189			$ 51,775,941	$ 1,752,322	$ 53,528,264		$ (10,526,122)	$ 41,249,819
190								
191			Breakout for Div 12 & Div 2:					
192		Div 12	$ 19,097,597		$ 19,241,253		$ (2,428,429)	$ 16,669,167
193							-12.72%	Div 12 % Capitalized Overhead
194								
195		Div 02	$ 32,678,345		$ 34,287,011		$ (8,097,693)	$ 24,580,652
196							-24.78%	Div 02 % Capitalized Overhead

Atmos SSU Gross Labor Exp recapitalization - Used for the determination of Gross Labor Exp/Cap Percents
For O&M Exp Accts (701-932) with Gross labor subs 01000,01001,01003,01006,01008,01009

Twelve Months Ended 9/30/09

Line	Div	CC	Tot O&M Exp	O&M Cap	Gross O&M Labor	SSU O/H Cap Rate	Exp Adj Add to Cap	Adjusted Expense
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
197	002	1001	$ 926,614	$ -	$ 926,614	51.47%	$ (476,928)	$ 449,686
198	002	1101	456,642	-	456,642	51.47%	(235,034)	221,609
199	002	1106	266,062	-	266,062	62.93%	(167,425)	98,637
200	002	1107	471,167	18,201	489,368	51.47%	(242,509)	228,657
201	002	1108	355,320	-	355,320	80.00%	(284,256)	71,064
202	002	1109	653,514	223	653,737	0.00%	-	653,514
203	002	1110	120,044	-	120,044	61.08%	(73,320)	46,724
204	002	1111	301,785	6,321	308,106	62.09%	(187,364)	114,421
205	002	1114	185,650	-	185,650	17.33%	(32,177)	153,473
206	002	1115	2,669,718	508	2,670,226	0.00%	-	2,669,718
207	002	1116	172,519	-	172,519	4.05%	(6,988)	165,532
208	002	1117	139,692	-	139,692	43.80%	(61,188)	78,504
209	002	1118	207,840	-	207,840	86.21%	(179,173)	28,668
210	002	1119	453,592	-	453,592	51.47%	(233,464)	220,128
211	002	1120	532,745	-	532,745	13.34%	(71,043)	461,702
212	002	1121	411,174	-	411,174	90.00%	(370,057)	41,117
213	002	1123	337,847	2,686	340,533	0.00%	-	337,847
214	002	1125	699,867	1,707	701,574	0.00%	-	699,867
215	002	1126	467,523	-	467,523	51.47%	(240,634)	226,889
216	002	1128	952,135	-	952,135	5.00%	(47,638)	904,497
217	002	1129	386,804	-	386,804	2.00%	(7,726)	379,078
218	002	1130	475,509	734	476,243	32.61%	(155,057)	320,451
219	002	1132	336,382	-	336,382	0.00%	-	336,382
220	002	1133	550,228	-	550,228	0.00%	-	550,228
221	002	1134	353,630	-	353,630	19.00%	(67,190)	286,440
222	002	1135	2,060,971	627,951	2,688,922	12.61%	(259,942)	1,801,029
223	002	1137	1,307,365	25,324	1,332,688	31.68%	(414,179)	893,186
224	002	1139	164,984	4,216	169,200	41.18%	(67,934)	97,049
225	002	1141	372,596	-	372,596	0.00%	-	372,596
226	002	1144	691,652	379	692,031	0.00%	-	691,652
227	002	1145	315,798	1,281	317,079	0.00%	-	315,798
228	002	1146	653,012	373,229	1,026,241	67.69%	(442,039)	210,973
229	002	1148	776,768	-	776,768	0.00%	-	776,768
230	002	1150	324,569	-	324,569	25.65%	(83,245)	241,324
231	002	1153	514,080	922	515,002	0.00%	-	514,080
232	002	1154	1,544,616	-	1,544,616	53.30%	(823,280)	721,336
233	002	1155	433,300	5,900	439,200	0.00%	-	433,300
234	012	1158	585,261	4,479	589,740	5.29%	(30,951)	554,310
235	002	1159	171,049	-	171,049	0.00%	-	171,049
236	002	1161	223,816	-	223,816	51.47%	(115,198)	108,618
237	002	1165	231,128	89,567	320,695	30.00%	(69,339)	161,790
238	002	1166	1,118,148	167,994	1,286,142	36.02%	(402,745)	715,403
239	002	1167	147,327	-	147,327	12.50%	(18,416)	128,911
240	002	1168	137,891	-	137,891	55.82%	(76,970)	60,921
241	002	1171	258,210	-	258,210	53.30%	(137,626)	120,584
242	002	1200	758,598	-	758,598	0.00%	-	758,598
243	002	1201	776,242	-	776,242	51.47%	(399,532)	376,710
244	012	1203	6,766,669	1,719	6,768,388	14.39%	(973,724)	5,792,945
245	002	1209	162,094	-	162,094	0.00%	-	162,094
246	012	1210	8,406,059	207	8,406,266	13.52%	(1,136,499)	7,269,560
247	012	1212	1,543	-	1,543	13.50%	(208)	1,334
248	002	1215	2,029,607	3,624	2,033,231	13.52%	(274,403)	1,755,204
249	012	1225	145,981	-	145,981	59.66%	(87,091)	58,890
250	012	1226	772,235	-	772,235	0.00%	-	772,235
251	012	1227	1,313,357	165,032	1,478,389	36.18%	(475,184)	838,172
252	012	1228	166,168	-	166,168	0.00%	-	166,168
253	002	1350	74,702	-	74,702	51.47%	(38,449)	36,253
254	002	1401	477,745	-	477,745	53.30%	(254,638)	223,107
255	002	1403	424,003	-	424,003	51.47%	(218,234)	205,769
256	002	1405	591,807	146	591,953	53.30%	(315,433)	276,374
257	002	1407	227,224	-	227,224	37.68%	(85,621)	141,603
258	002	1408	286,902	-	286,902	0.00%	-	286,902
259	002	1411	473,250	9,845	483,096	0.00%	-	473,250
260	002	1412	149,844	-	149,844	0.00%	-	149,844
261	002	1414	550,012	3,060	553,072	0.00%	-	550,012
262	002	1415	116,824	-	116,824	0.00%	-	116,824
263	002	1501	1,693,620	-	1,693,620	19.03%	(322,332)	1,371,288
264	002	1502	115,579	-	115,579	0.00%	-	115,579
265	002	1503	299,851	-	299,851	0.00%	-	299,851
266	002	1504	82,629	-	82,629	0.00%	-	82,629
267	002	1505	161,246	405	161,651	0.00%	-	161,246
268	002	1821	265,955	-	265,955	0.00%	-	265,955
269	002	1822	166,816	-	166,816	0.00%	-	166,816
270	002	1823	228,019	-	228,019	0.00%	-	228,019
271	002	1825	213,389	-	213,389	0.00%	-	213,389
272	002	1826	268,218	-	268,218	0.00%	-	268,218
273	002	1827	166,716	-	166,716	0.00%	-	166,716
274	002	1828	395,959	-	395,959	0.00%	-	395,959
275	002	1829	303,628	633	304,262	0.00%	-	303,628
276	002	1831	571,555	-	571,555	0.00%	-	571,555
277	002	1832	166,031	-	166,031	0.00%	-	166,031
278	002	1833	49,243	-	49,243	0.00%	-	49,243
279	002	1835	613,156	-	613,156	0.00%	-	613,156
280	002	1836	239,395	1,360	240,755	0.00%	-	239,395
281	002	1837	449,988	77,760	527,749	0.00%	-	449,988
282	002	1838	354,654	38,448	393,102	0.00%	-	354,654
283	002	1839	130,228	-	130,228	0.00%	-	130,228
284	002	1901	247,053	-	247,053	0.00%	-	247,053
285	002	1913	284,193	-	284,193	43.43%	(123,412)	160,781
286			$ 57,054,530	$ 1,633,863	$ 58,688,393		$ (10,785,795)	$ 46,268,735
287								
288	Breakout for Div 12 & Div 2:							
289		Div12	$ 18,157,271		$ 18,328,708		$ (2,703,657)	$ 15,453,614
290							-14.89%	Div 12 % Capitalized Overhead
291								
292		Div02	$ 38,897,258		$ 40,359,684		$ (8,082,138)	$ 30,815,121
293							-20.78%	Div 02 % Capitalized Overhead

Source: See Relied 1n - SSU Payroll by Cost Center and Relied 1.1n SSU Capitalized OH Study

Atmos Energy Corporation
Kansas Jurisdiction
Benefits Adjustment - Pensions & Insurance
Twelve Months Ended September 30, 2011

						Admin & General Offices					
Line No.	Description	Liberty Div 79	Kansas Div 81	Southwest Div 86	Total Direct Kansas	Shared Srvc Gen Office Div 02	Shared Srvc Cust Support Div 12	COKS Gen Office Div 30	Kansas Admin Div 80	Total (e thru i)	Source
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	KS Juris Labor Expense Adjustment	$ 928	$ 129,096	$ 5,464	$ 135,488	$ 22,564	$ 17,632	$ 25,396	$ 11,534	$ 212,613	**WP 9-2**
2											
3	Fiscal 2012 Budget Benefits %	39.75%	39.75%	39.75%		35.17%	35.17%	39.75%	39.75%		**FY12 Budget**
4											
5	Benefits Adjustment	$ 369	$ 51,313	$ 2,172	$ 53,853	$ 7,936	$ 6,202	$ 10,094	$ 4,585	$ 82,670	
6											
7	Allocations:										
8											
9	Atmos Shared Services - General Office Div 02 (a)				$ 7,936	$ (7,936)	$ -	$ -	$ -	$ -	
10	Atmos Shared Services - Customer Support Div 12 (b)				6,202		(6,202)			-	
11	CO/KS Business Unit General Office Div 30 (a)				10,094			(10,094)		-	
12	Kansas Admin Div 80 (a)				4,585				(4,585)	-	
13	Total KS jurisdictional Benefit Expense Adjustment				$ 82,670	$ -	$ -	$ -	$ -	$ 82,670	**IS-2**
14											
15	(a) Allocations - Composite										
16	(b) Allocations - Customers										
17											
18											

Line No.		Co. 60 CO/KS BU	Co. 10 SSU BU
19		Co. 60	Co. 10
20		CO/KS BU	SSU BU
21	*** FY12 budgeted Benefits Percent Calc:**		
22	Budgeted Medical, Dental, Pension Benefits	$ 6,939,399	$ 24,943,150
23	Budgeted Workers Comp Benefits	$ 339,874	$ 149,376
24			
25	Total actuarial benefits - FY12 Budget	$ 7,279,274	$ 25,092,526
26	Gross Labor - FY12 Budget	$ 18,313,717	$ 71,340,888
27	Budgeted Benefits as a Percent of Labor	**39.75%**	**35.17%**
28			

Atmos Energy Corporation
Kansas Jurisdiction
American Gas Association Dues Adjustment
For the twelve months ended September 30, 2011
Div 30, Account 9302, Sub Account 07510

Line	Period	Line Description	FERC	Reference	Total	
	(a)	(b)	(c)	(d)	(e)	
1	Oct-10	Amort AGA Dues	9302-07510		$ 3,923	
2	Nov-10	Amort AGA Dues	9302-07510		3,923	
3	Dec-10	Amort AGA Dues	9302-07510		3,923	
4	Jan-11	Amort AGA Dues	9302-07510		4,204	
5	Feb-11	Amort AGA Dues	9302-07510		4,204	
6	Mar-11	Amort AGA Dues	9302-07510		4,204	
7	Apr-11	Amort AGA Dues	9302-07510		4,204	
8	May-11	Amort AGA Dues	9302-07510		4,204	
9	Jun-11	Amort AGA Dues	9302-07510		4,204	
10	Jul-11	Amort AGA Dues	9302-07510		4,204	
11	Aug-11	Amort AGA Dues	9302-07510		4,204	
12	Sep-11	Amort AGA Dues	9302-07510		4,204	
13						
14		AGA Dues Total Div 30			$ 49,608	
15						
16		AGA Dues Oct10-Dec10	9302-07510		$ 11,769	
17		AGA Dues Jan11-Sep11	9302-07510		37,839	
18					$ 49,608	
19						
20	2010 Percent Advertising & Public Affairs			Source: AGA 2010 Budget	23.81%	**WP 9-4-1**
21	2011 Percent Advertising & Public Affairs			Source: AGA 2011 Budget	25.28%	**WP 9-4-1**
22						
23	Remove AGA Dues for Advertising and Public Affairs					
24	2010 AGA dues for Advertising & Public Affairs			AGA Dues Oct10-Dec10	$ (2,802)	
25	2011 AGA dues for Advertising & Public Affairs			AGA Dues Jan11-Sep11	(9,566)	
26					$ (12,368)	
27	Kansas Div 30 General Office Allocation			Source: Sect. 12 Alloc	58.24%	
28	Kansas Jurisdictional Adjustment to Remove AGA Advertising and Public Affairs Dues				$ (7,203)	**IS-3**

Source: See Relied 1r - AGA Amort Dues

AMERICAN GAS ASSOCIATION
2011 BUDGET

Line No.	Description	Amount	Percentage
	(a)	(b)	(c)
1	Advertising	$ 525,000	1.98%
2	Corporate Affairs	2,092,000	7.89%
3	General & Administrative	5,138,000	19.38%
4	General Counsel	1,207,000	4.55%
5	Industry Finance & Administrative Prog.	1,198,000	4.52%
6	Operations & Engineering Management	5,691,000	21.47%
7	Policy, Planning & Regulatory Affairs	4,482,000	16.91%
8	Public Affairs	6,177,000	23.30%
9			
10	Total Budget	$ 26,510,000	100.00%
11			
12	2011 Percent Advertising & Public Affairs		25.28%
13	2011 Percent AGA Recoverable Dues		74.72%
14			
15			
16	AMERICAN GAS ASSOCIATION		
17	2010 BUDGET		
18			
19	Advertising	$ 250,000	1.04%
20	Corporate Affairs	2,362,000	9.79%
21	General & Administrative	5,112,000	21.18%
22	General Counsel	1,125,000	4.66%
23	Industry Finance & Administrative Programs	915,000	3.79%
24	Operations & Engineering Management	4,810,000	19.93%
25	Policy, Planning & Regulatory Affairs	4,063,000	16.84%
26	Public Affairs	5,495,000	22.77%
27			
28	Total Budget	$ 24,132,000	100.00%
29			
30	2010 Percent Advertising & Public Affairs		23.81%
31	2010 Percent AGA Recoverable Dues		76.19%

Source: AGA Budget Breakdown

WP 9-5
IS-4

Atmos Energy Corporation
Kansas Jurisdiction
Charitable Donations Adjustment
For the twelve months ended September 30, 2011

Line No.	Description	Total Kansas	
	(a)	(b)	
1	Test Year Charitable Donations (Adjusted 50%)	$ 78,707	**See Ln. 18, Column (i)**
2			
3			

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
5	**FERC Account 4261 Charitable Donations - Below the Line**		KS Div	SW Div	SSU	CSC	CoKs GO	KS Admin		
6	Sub Acct Description	Sub Acct	81	86	2	12	30	80	Grand Total	
7	Education	30702	$ 150	$ -	$ 164,768	$ -	$ -	$ 250	$ 165,168	
8	United Way Agencies	30703	-	-	377,692	32	-	12,896	390,620	
9	Health	30705	-	-	77,359	-	3,250	2,500	83,109	
10	Museums & Arts	30706	-	-	1,005,000	-	-	1,000	1,006,000	
11	Youth Clubs & Centers	30710	-	-	-	-	-	3,575	3,575	
12	Heat Help Assist. Program	30711	-	-	300,233	-	-	25,000	325,233	
13	Community Welfare	30736	-	-	157,379	5,997	32,015	6,499	201,890	
14	Per Book Charitable Donations Acct 4261		$ 150	$ -	$ 2,082,431	$ 6,029	$ 35,265	$ 51,720	$ 2,175,595	
15	KS Allocation Rate (Schedule 12)		100%	100%	4.07%	4.17%	58.24%	100%		
16	KS Jurisdictional Charitable Donations		$ 150	$ -	$ 84,755	$ 251	$ 20,538	$ 51,720	$ 157,415	
17										
18	50% Donations Recoverable in Cost of Service	50%	$ 75	$ -	$ 42,377	$ 126	$ 10,269	$ 25,860	**$ 78,707**	**IS-4**

Source: See Relied File 1s - Donations

Atmos Energy Corporation
Kansas Distribution System
Per Book Analysis of Donation Sub Accts
Twelve Months Ended 9/30/11

Line	FERC Acct	Sub Account	81	86	2	12	30	80	Grand Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	4261	30702	$ 150	$ -	$ 164,768	$ -	$ -	$ 250	$ 165,168	
2	4261	30703			377,692	32		12,896	390,620	
3	4261	30705			77,359		3,250	2,500	83,109	
4	4261	30706			1,005,000			1,000	1,006,000	
5	4261	30709							-	
6	4261	30710						3,575	3,575	
7	4261	30711			300,233			25,000	325,233	
8	4261	30736			157,379	5,997	32,015	6,499	201,890	
9	4264	30736							-	Exclude
10	4264	30737			96,483		94	32,483	129,060	Exclude Political
11	4264	30743			414				414	Exclude Sporting
12	4265	30702						1,750	1,750	Exclude
13	4265	30705				3,000			3,000	Exclude
14	4265	30736	450			2,854			3,304	Exclude
15	4265	30743	415	1	16,124	1,000	84,927	7,637	110,104	Exclude Sporting
16	Grand Total Per Book		$ 1,015	$ 1	$ 2,195,451	$ 12,883	$ 120,286	$ 93,591	$ 2,423,226	
17										
18	Excluded Expense		$ (865)	$ (1)	$ (113,020)	$ (6,854)	$ (85,021)	$ (41,870)	$ (247,632)	
19	Total Acct 4261 Donations		$ 150	$ -	$ 2,082,431	$ 6,029	$ 35,265	$ 51,720	$ 2,175,595	Per book

20
21
22 List of Charitable Donation Sub Accounts:
23

Line	Sub	Sub Description
24	Sub	Sub Description
25	30702	Education
26	30703	United Way Agencies
27	30705	Health
28	30706	Museums & Arts
29	30709	Salvation Army
30	30710	Youth Clubs & Centers
31	30711	Heat Help Assist. Program
32	30713	American Red Cross
33	30736	Community Welfare
34	30737	Political Activities
35	30742	Membership/Club Dues
36	30743	Sports Events

Source: Relied 1s - Donations

Atmos Energy Corporation
Kansas Distribution System
Estimated Rate Case Expense Amortization
Twelve Months Ended September 30, 2009

Line No.	Category		Description		Amount
	(a)		(b)		(c)
1	Estimated Rate Case Expenses:				
2	Consulting Fees		William E. Avera (ROE Witness)	$	50,000
3	Legal Fees		James G. Flaherty (Anderson & Byrd LLP)		150,000
4	Consulting Fees		Dane Watson (Depreciation Witness)		60,000
5	Employee Expenses		Airfare, lodging, meals, etc.		40,000
6	Miscellaneous Expenses		Printing, postage, advertising, etc.		30,000
7	Rate Case Expense related to 2009 rate case	[1]	Remaining amortization amounts from 2009 rate case		90,000
8					
9	Total Estimated Rate Case Expenses			$	420,000
10					
11	2 Year Amortization			$	210,000 **IS-5**
12					
13	Note:				
14	[1] Amount represents the 1 year remaining of the 3 year amortization of the 2009 rate case expenses;				
15	adjustment amortizes estimated Rate Case Expense over two years.				

Atmos Energy Corporation
Kansas Distribution System
Adjustment for Expense Reports and Other Misc Employee Expenses
Twelve Months Ended 9/30/11

Line No.	Description	Expense Reports	Other Misc Employee Exp	Total Before Alloc	Allocation %	Total KS	
	(a)	(b)	(c)	(d)	(e)	(f)	
1	All Kansas	$ 40,996	$ 14,195	$ 55,191	100%	$ 55,191	
2	CSC (Div 012)	54,641	12,264	66,905	4.17%	2,790	
3	SSU (Div 002)	197,643	90,786	288,429	4.07%	11,739	
4							
5	Total	$ 293,280	$ 117,245	$ 410,525		$ 69,720	**IS-6**
6							

7 To remove expense report items and other misc employee expenses that Staff or CURB might determine
8 are inappropriate to recover from ratepayers.

See Relied File 7a
See Relied 7b - FY 2011 review of specific expenses- KS rate case
See Relied File 7c
Section 12 Allocations

Atmos Energy Corporation
Kansas Distribution System
Computation of Per Books, Allocated, Income Statement Items
Twelve Months Ended September 30, 2011

Line No.	Description	30 CO/KS GO	80 KS Admin	Allocated Total KS	Direct Total KS	Direct & Allocated Total KS
	(a)	(b)	(c)	(d)	(e)	(f)
1	Revenues	$ -	$ -	$ -	$ 119,372,318	$ 119,372,318
2	Gas Cost	0	0	0	70,495,708	70,495,708
3	Margin	$ -	$ -	$ -	$ 48,876,610	$ 48,876,610
4	O&M	$ 0	$ (0)	$ (0)	$ 18,108,292	$ 18,108,292
5	Depreciation	(0)	0	0	9,725,275	9,725,275
6	Taxes, Other	0	0	0	6,515,265	6,515,265
7	Income Taxes - Current	1,168,193	(307,622)	372,734	3,984,323	4,357,057
8	Interest on Customer Deposits	-	-	0	11,995	11,995
9	Other Income and Deductions	(0)	(824,154)	(824,154)	162,063	(662,091)
10	Interest	(0)	824,154	824,154	5,051,207	5,875,361
11						
12	Net Income	$ (1,168,193)	$ 307,622	$ (372,734)	$ 5,318,190	$ 4,945,456

Source: See Relied File 8

Atmos Energy Corporation
Kansas Distribution System
Pension/Post Retirement Benefits Adjustment
Twelve Months Ended September 30, 2011

WP 9-9
IS-15

Line #	Month/Yea	Amount in Base Rates	Cumulative	Actual/ Estimated Pension Expense	Cummulative	Expense in Excess of (Less than) Amount In Base Rates	Cummulative
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	FAS 87						
2	Aug-10	$ 54,380	$ 54,380	$ 41,274	$ 41,274	$ (13,106)	$ (13,106)
3	Sep-10	54,380	108,760	41,733	83,008	(12,647)	(25,752)
4	Oct-10	54,380	163,140	57,004	140,011	2,624	(23,129)
5	Nov-10	54,380	217,520	60,199	200,210	5,819	(17,310)
6	Dec-10	54,380	271,900	52,922	253,132	(1,458)	(18,768)
7	Jan-11	54,380	326,280	47,019	300,151	(7,361)	(26,129)
8	Feb-11	54,380	380,660	51,493	351,643	(2,887)	(29,017)
9	Mar-11	54,380	435,040	46,240	397,883	(8,140)	(37,157)
10	Apr-11	54,380	489,420	66,320	464,203	11,940	(25,217)
11	May-11	54,380	543,800	47,442	511,644	(6,938)	(32,156)
12	Jun-11	54,380	598,180	55,136	566,781	756	(31,399)
13	Jul-11	54,380	652,560	46,746	613,526	(7,634)	(39,034)
14	Aug-11	54,380	706,940	46,019	659,545	(8,361)	(47,395)
15	Sep-11	54,380	761,320	58,132	717,677	3,752	(43,643)
16	Oct-11	54,380	815,700	67,197	784,874	12,817	(30,826)
17	Nov-11	54,380	870,080	67,707	852,581	13,327	(17,499)
18	Dec-11	54,380	924,460	67,707	920,288	13,327	(4,172)
19	Jan-12	54,380	978,840	67,707	987,995	13,327	9,155
20	Feb-12	54,380	1,033,220	67,707	1,055,702	13,327	22,482
21	Mar-12	54,380	1,087,600	67,707	1,123,409	13,327	35,809
22	Apr-12	54,380	1,141,980	67,707	1,191,117	13,327	49,137
23	May-12	54,380	1,196,360	67,707	1,258,824	13,327	62,464
24	Jun-12	54,380	1,250,740	67,707	1,326,531	13,327	75,791
25	Jul-12	54,380	1,305,120	67,707	1,394,238	13,327	89,118
26	Aug-12	54,380	1,359,500	67,707	1,461,945	13,327	102,445
27	Sep-12	54,380	1,413,880	67,707	1,529,652	13,327	115,772
28	Amortization of FAS 87 Excess (Less Than) Funding over 3 Years						$ 38,591
29	FAS 106						
30	Aug-10	$ 51,661	$ 51,661	$ 48,598	$ 48,598	$ (3,063)	$ (3,063)
31	Sep-10	51,661	103,322	49,138	97,736	(2,523)	(5,586)
32	Oct-10	51,661	154,983	47,647	145,383	(4,014)	(9,600)
33	Nov-10	51,661	206,644	50,318	195,701	(1,343)	(10,943)
34	Dec-10	51,661	258,305	44,236	239,937	(7,425)	(18,368)
35	Jan-11	51,661	309,966	48,469	288,406	(3,192)	(21,560)
36	Feb-11	51,661	361,627	53,081	341,487	1,420	(20,140)
37	Mar-11	51,661	413,288	36,885	378,372	(14,776)	(34,916)
38	Apr-11	51,661	464,949	67,690	446,062	16,029	(18,887)
39	May-11	51,661	516,610	48,609	494,670	(3,052)	(21,940)
40	Jun-11	51,661	568,271	55,827	550,497	4,166	(17,774)
41	Jul-11	51,661	619,932	47,450	597,947	(4,211)	(21,985)
42	Aug-11	51,661	671,593	47,030	644,977	(4,631)	(26,616)
43	Sep-11	51,661	723,254	56,776	701,753	5,115	(21,501)
44	Oct-11	51,661	774,915	69,780	771,534	18,119	(3,381)
45	Nov-11	51,661	826,576	60,407	831,941	8,746	5,365
46	Dec-11	51,661	878,237	60,407	892,348	8,746	14,111
47	Jan-12	51,661	929,898	60,407	952,755	8,746	22,857
48	Feb-12	51,661	981,559	60,407	1,013,163	8,746	31,604
49	Mar-12	51,661	1,033,220	60,407	1,073,570	8,746	40,350
50	Apr-12	51,661	1,084,881	60,407	1,133,977	8,746	49,096
51	May-12	51,661	1,136,542	60,407	1,194,385	8,746	57,843
52	Jun-12	51,661	1,188,203	60,407	1,254,792	8,746	66,589
53	Jul-12	51,661	1,239,864	60,407	1,315,199	8,746	75,335
54	Aug-12	51,661	1,291,525	60,407	1,375,606	8,746	84,081
55	Sep-12	51,661	1,343,186	60,407	1,436,014	8,746	92,828
56	Amortization of Excess (Less Than) Funding over 3 Years						$ 30,943
57	Total Amortization						$ 69,534 IS-15

Atmos Energy Corporation
Kansas Distribution System
Depreciation and Amortization Expense
Twelve Months Ended September 30, 2011

Section 10
IS-7

Line No.	Description	Reference		Total	FERC	
	(a)	(b)		(c)	(d)	
1	Depreciation and Amortization Expense	WP 9-8	$	9,725,275	4030, 4060	
2						
3	Depreciation and Amortization Expense Adjustment			3,622,098	4030	IS-7
4	Total Depreciation and Amortization Expense, As Adjusted	WP 10-1 thru 10-7	$	13,347,372		
5						
6	Note:					
7	Adjustment reflects the pro-forma depreciation expense associated with the adjusted test-year end plant in service					
8	balances and includes the Company's recommended depreciation rates for the Colorado-Kansas Division operating					
9	division general office (Service Area 30).					

Kansas Distribution System
Depreciation Adjustment
As of test period end September 30, 2011
Kansas Direct Plant

Line No.	Description	Property Type	Balance at 9/30/11	Amortization Retirements [2]	Fully & Non-Depreciable Plant	Depreciable Plant	Current Depreciation Rates: Depreciation Rates	Current Depreciation Rates: Pro-Forma Depreciation Expense	Current Depreciation Rates: Pro-Forma Capitalized Depr Exp (1)	Recommended Depreciation Rates: Depreciation Rates	Recommended Depreciation Rates: Pro-Forma Depreciation Expense	Recommended Depreciation Rates: Pro-Forma Capitalized Depr Exp (1)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Intangible Plant											
1	Franchises & Consents	30200	$ 37,160	$ -	$ 37,160	$ -	0.00%	$ -	$ -	0.00%	$ -	$ -
2	Misc. Intangible Plant	30300	3,918		3,918	0	0.00%	-		0.00%	-	
3	**Total Intangible Plant**		$ 41,078	$ -	$ 41,078	$ -	0.00%	$ -	$ -	0.00%	$ -	$ -
4												
5	**Storage Plant**											
6	Land	35010	$ 49,164	$ -	$ 49,164	$ -	0.00%	$ -	$ -	0.00%	$ -	$ -
7	Rights-of-way	35020	568,935			568,935	3.05%	17,353		1.76%	10,013	
8	Well Structures	35100	102,923			102,923	2.18%	2,244		2.13%	2,192	
9	Wells	35200	1,136,225			1,136,225	4.62%	52,494		2.15%	24,429	
10	Reservoirs	35202	36,515		36,515	0	3.09%	-		3.09%	-	
11	Leaseholds	35210	0			0	3.00%	-		3.00%	-	
12	Pipelines	35300	1,145,818			1,145,818	2.32%	26,583		2.36%	27,041	
13	Compressor Station Equipment	35400	2,259,430			2,259,430	4.02%	90,829		2.90%	65,523	
14	Meas. & Reg. Equipment	35500	220,011			220,011	4.69%	10,319		2.72%	5,984	
15	Purification Equipment	35600	288,382			288,382	4.37%	12,602		1.80%	5,191	
16	Other Equip	35700	125,321			125,321	3.07%	3,847		2.10%	2,632	
17	**Total Storage Plant**		$ 5,932,723	$ -	$ 85,679	$ 5,847,044	3.70%	$ 216,270	$ -	2.45%	$ 143,006	$ -
18												
19	**Transmission Plant**											
20	Land and Land Rights	36500	$ 11,252	$ -	$ 11,252	$ -	0.00%	$ -	$ -	0.00%	$ -	$ -
21	Rights-of-Way	36520	9,037			9,037	1.95%	176		2.12%	192	
22	Structures & Improvements	36600	33,191			33,191	1.89%	627		2.89%	959	
23	Mains - Cathodic Protection	36700	3,452,904			3,452,904	1.64%	56,628		2.36%	81,489	
24	Mains - Steel	36701	143,453			143,453	1.64%	2,353		3.44%	4,935	
25	Anodes	36703	2,795	461		2,334	1.64%	38		4.57%	107	
26	Leak Clamps & Sleeves	36704	23,155	23,155		0	1.64%	0		8.33%	0	
27	Compressor Station Equipment	36800	31,496			31,496	5.47%	1,723		5.96%	1,877	
28	M&R Station Equipment	36900	526,227			526,227	2.09%	10,998		4.19%	22,049	
29	Other Equipment	37100	0			0	7.07%	-		7.07%	-	
30	**Total Transmission Plant**		$ 4,233,511	$ 23,616	$ 11,252	$ 4,198,643	1.73%	$ 72,543	$ -	2.66%	$ 111,607	$ -
31												
32	**Distribution Plant**											
33	Land & Land Rights	37400	$ 670,983	$ -	$ 670,983	$ -	0.00%	$ -	$ -	0.00%	$ -	$ -
34	Land Rights	37402	292,603			292,603	2.92%	8,544		2.12%	6,203	
35	Structures & Improvements	37500	119,494			119,494	3.10%	3,704		4.27%	5,102	
36	Mains - Cathodic Protection	37600	4,179,130			4,179,130	2.02%	84,418		3.33%	139,165	
37	Mains - Steel	37601	32,805,123			32,805,123	2.02%	662,663		3.08%	1,010,398	
38	Mains - Plastic	37602	78,899,087			78,899,087	2.02%	1,593,762		3.24%	2,556,330	
39	Anodes	37603	3,059,067	73,997		2,985,071	2.02%	60,298		7.19%	214,627	
40	Leak Clamps & Sleeves	37604	6,596,575	1,002,453		5,594,122	2.02%	113,001		14.20%	794,365	
41	Meas. & Reg. Sta. Eq-General	37800	3,571,277			3,571,277	4.74%	169,279		5.33%	190,349	
42	Meas. & Reg. City Gate	37900	2,207,812			2,207,812	2.53%	55,858		4.16%	91,845	

Kansas Distribution System
Depreciation Adjustment
As of test period end September 30, 2011
Kansas Direct Plant

Line No.	Description	Property Type	Balance at 9/30/11	Amortization Retirements [2]	Fully & Non-Depreciable Plant	Depreciable Plant	Current Depreciation Rates: Depreciation Rates	Current Depreciation Rates: Pro-Forma Depreciation Expense	Current Depreciation Rates: Pro-Forma Capitalized Depr Exp (1)	Recommended Depreciation Rates: Depreciation Rates	Recommended Depreciation Rates: Pro-Forma Depreciation Expense	Recommended Depreciation Rates: Pro-Forma Capitalized Depr Exp (1)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
43	Meas. & Reg. Sta. Eq-	37908	14,851			14,851	2.53%	376		4.14%	615	
44	Services	38000	57,635,135			57,635,135	3.49%	2,011,466		5.41%	3,118,061	
45	Meters	38100	15,021,142			15,021,142	5.12%	769,082		6.93%	1,040,965	
46	Meter Installations	38200	23,917,803			23,917,803	6.86%	1,640,761		7.39%	1,767,526	
47	House Regulators	38300	2,209,798			2,209,798	2.66%	58,781		6.70%	148,056	
48	House Reg. Installations	38400	209,461			209,461	1.65%	3,456		7.23%	15,144	
49	Ind. Meas. & Reg. Sta. Equip	38500	951,405			951,405	3.78%	35,963		6.29%	59,843	
50	Other Equipment	38700	613,755			613,755	15.08%	92,554		7.47%	45,847	
51	**Total Distribution Plant**		$ 232,974,503	$ 1,076,449	$ 670,983	$ 231,227,070	3.18%	$ 7,363,967	$ -	4.85%	$ 11,204,443	$ -
52												
53	**General Plant**											
54	Land & Land Rights	38900	$ 152,535	$ -	$ 152,535	$ -	0.00%	$ -	$ -	0.00%	$ -	$ -
55	Structures & Improvements	39000	1,853,668			1,853,668	3.31%	61,356		3.26%	60,430	
56	Improvements	39003	1,513			1,513	3.31%	50		4.15%	63	
57	Air Conditioning Equipment	39004	8,782			8,782	3.31%	291		4.17%	366	
58	Improv. to Leased Premises	39009	39,013			39,013	3.31%	1,291		4.20%	1,639	
59	Office Furniture & Equipment	39100	430,210	5,442		424,768	12.20%	51,822		7.38%	31,348	
60	Office Furn. Copiers & Type	39103	5,220			5,220	12.20%	637		7.38%	385	
61	Transportation Equipment	39200	645,302			645,302	25.98%	16,231	151,418	17.99%	11,240	104,850
62	Stores Equipment	39300	1,308			1,308	7.85%	52	51	4.69%	31	30
63	Tools, Shop, & Garage Equip.	39400	2,565,050	91,970		2,473,080	8.03%	99,837	98,752	7.72%	95,982	94,939
64	Laboratory Equipment	39500	21,223	7,165		14,057	5.13%	363	358	7.98%	564	557
65	Power Operated Equipment	39600	490,962			490,962	16.62%	1,632	79,966	14.31%	1,405	68,852
66	Ditchers	39603	101,192		101,192	0	16.62%	-	-	16.62%	-	-
67	Backhoes	39604	203,475			203,475	16.62%	676	33,141	15.03%	612	29,971
68	Welders	39605	54,819			54,819	16.62%	182	8,929	14.52%	159	7,801
69	Communication Equipment	39700	410,879			410,879	11.96%	49,141		8.93%	36,691	
70	Comm. Equip. Mobile Radios	39701	7,902			7,902	11.96%	945		16.38%	1,294	
71	Comm. Equip. Fixed Radios	39702	6,065			6,065	11.96%	725		8.89%	539	
72	Miscellaneous Equipment	39800	7,076			7,076	6.59%	466		6.85%	485	
73	Other Tangible Property	39900	0			0	7.21%	-		7.21%	-	
74	Oth Tang Prop - Servers - H/W	39901	25,349			25,349	7.21%	1,828		15.28%	3,873	
75	Oth Tang Prop - Servers - S/W	39902	63,702			63,702	7.21%	4,593		17.92%	11,415	
76	Oth Tang Prop Network H/W	39903	180,428			180,428	7.21%	13,009		16.82%	30,348	
77	Oth Tang Prop PC Hardware	39906	1,132,569	544,073		588,496	7.21%	42,431		32.78%	192,909	
78	Oth Tang Prop PC Software	39907	84,070			84,070	7.21%	6,061		30.37%	25,532	
79	Oth Tang Prop Appl Software	39908	213,445			213,445	7.21%	15,389		17.19%	36,691	
80	**Total General Plant**		$ 8,705,755	$ 648,650	$ 253,727	$ 7,803,378	4.73%	$ 369,009	$ 372,615	6.97%	$ 544,002	$ 307,000
81												
82	**Total Kansas Direct**		$ 251,887,570	$ 1,748,716	$ 1,062,719	$ 249,076,136	3.22%	$ 8,021,789	$ 372,615	4.82%	$ 12,003,057	$ 307,000
83												

Kansas Distribution System
Depreciation Adjustment
As of test period end September 30, 2011
Kansas Direct Plant

Line No.	Description	Property Type	Balance at 9/30/11	Amortization Retirements [2]	Fully & Non-Depreciable Plant	Depreciable Plant	Current Depreciation Rates: Depreciation Rates	Current Depreciation Rates: Pro-Forma Depreciation Expense	Current Depreciation Rates: Pro-Forma Capitalized Depr Exp (1)	Recommended Depreciation Rates: Depreciation Rates	Recommended Depreciation Rates: Pro-Forma Depreciation Expense	Recommended Depreciation Rates: Pro-Forma Capitalized Depr Exp (1)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
84	**Summary for Total KS Jurisdiction**											
85	Allocation of Shared Services - General office (WP 10-2)							$ 591,428			$ 441,795	
86	Allocation of Shared Services - Customer Support (WP 10-3)							871,663			611,208	
87	Allocation of Operating Company General Office (WP 10-4)							291,313			291,313	
88												
89	Total Kansas Jurisdiction							$ 9,776,193			$ 13,347,372	

90
91 [1] For vehicle & POE depreciation expense, a portion of it is capitalized & some or all of the remaining balance is moved to account 8740. what determines whether or not the
92 non- capitalized portion moves to 8740 or stays in 4030 is whether or not the expense hits the default cost center (0000) or a cost center. If it hits the default cost center (0000),
93 the non- capitalized portion stays in 4030. For vehicles the rate of capitalization is determined by which cost center the expense hits. If it hits the default cost center (0000), the
94 rate is the overall company rate. If it hits a cost center, the rate is the individual cost center rate. The rate of capitalization for POE for FY 2009 is a fixed 85% regardless of the cost
95 center it hits.
96 For the other capitalized depreciation categories: 39300, 39400 & 39500 the capitalization rate is based on the same as above. The only difference is that the balance
97 (non-capitalized portion) stays in 4030.
98
99 [2] Proforma adjustment to reflect the implementation of Amortization.

Kansas Distribution System
Depreciation Adjustment
As of test period end September 30, 2011
SSU Div 2

Line No.	Description	Property Type	Balance at 9/30/11	Fully & Non-Depreciable Plant	Depreciable Plant	Current Depreciation Rates: Depreciation Rates	Current Depreciation Rates: Pro-Forma Depreciation Expense	Current Depreciation Rates: Pro-Forma Capitalized Depr Exp	Recommended Depreciation Rates: Depreciation Rates	Recommended Depreciation Rates: Pro-Forma Depreciation Expense	Recommended Depreciation Rates: Pro-Forma Capitalized Depr Exp
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	General Plant										
1	Structures & Improvements	390	$ -	$ -	$ -	7.43%	$ -	$ -	3.34%	$ -	$ -
2	Improv. to Leased Premises	390.9	8,253,038		8,253,038	9.10%	751,026		4.06%	335,073	
3	Office Furniture & Equipment	391	11,475,202		11,475,202	2.13%	244,422		4.03%	462,451	
4	Remittance Processing Equipme	391.2	0		0	2.13%	-		4.03%	-	
5	Office Furn. Copiers & Type	391.3	0		0	2.13%	-		4.03%	-	
6	Transportation Equipment	392	96,290		96,290	10.32%	9,937		10.32%	9,937	
7	Tools, Shop, & Garage Equip.	394	83,933		83,933	10.32%	8,662		8.88%	7,453	
8	Communication Equipment	397	2,355,236		2,355,236	8.45%	199,017		5.54%	130,480	
9	Miscellaneous Equipment	398	236,331		236,331	8.15%	19,261		1.72%	4,065	
10	Other Tangible Property	399	162,268		162,268	4.66%	7,562		13.84%	22,458	
11	Oth Tang Prop Servers H/W	399.1	24,760,357		24,760,357	6.95%	1,720,845		8.62%	2,134,343	
12	Oth Tang Prop Servers S/W	399.2	13,285,696		13,285,696	4.00%	531,428		8.78%	1,166,484	
13	Oth Tang Prop Network H/W	399.3	3,911,025		3,911,025	9.30%	363,725		8.72%	341,041	
14	Oth Tang Prop CPU	399.4	1,095,465	1,095,465	0	10.32%	-		10.32%	-	
15	Oth Tang Prop MF Hardware	399.5	1,159,964	1,159,964	0	10.32%	-		10.32%	-	
16	Oth Tang Prop PC Hardware [1]	399.6	4,697,255		4,697,255	14.86%	698,012		8.78%	412,419	
17	Oth Tang Prop PC Software	399.7	1,769,409		1,769,409	9.02%	159,601		6.64%	117,489	
18	Oth Tang Prop Appl Software	399.8	82,235,740		82,235,740	11.11%	9,136,391		6.57%	5,402,888	
19	Oth Tang Prop Mainframe S/W	399.9	2,614,619	2,614,619	0	10.32%	-		10.32%	-	
20											
21			$ 158,191,829	$ 4,870,048	$ 153,321,780	9.03%	$ 13,849,889	$ -	6.88%	$ 10,546,581	$ -
22											
23											
24											
25											
26	General Plant										
27	Greenville Data Center										
28	G-Structures & Improvements	390.5	$ 9,154,286	$ -	$ 9,154,286	7.43%	$ 680,163	$ -	3.34%	$ 305,753	$ -
29	G-Office Furniture & Equip.	391.4	63,741		63,741	2.13%	1,358		4.03%	2,569	
30			$ 9,218,027	$ -	$ 9,218,027		$ 681,521	$ -		$ 308,322	$ -
31											
32											
33											
34	Total SSU General Office (Ln 21+ Ln 30)		$ 167,409,855	$ 4,870,048	$ 162,539,807		$ 14,531,410	$ -		$ 10,854,903	$ -
35											
36											
37											
38	Note:										
39	[1] Reclassification of CSU office property incorrectly booked to SSU, see WP 5-5 for details										

Kansas Distribution System
Depreciation Adjustment
As of test period end September 30, 2009
SSU Div 12

Line No.	Description	Property Type	Balance at 9/30/11	Fully & Non-Depreciable Plant	Depreciable Plant	Current Depreciation Rates: Depreciation Rates	Current Depreciation Rates: Pro-Forma Depreciation Expense	Current Depreciation Rates: Pro-Forma Capitalized Depr Exp	Recommended Depreciation Rates: Depreciation Rates	Recommended Depreciation Rates: Pro-Forma Depreciation Expense	Recommended Depreciation Rates: Pro-Forma Capitalized Depr Exp
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Land	38900	$ 2,874,240	$ -	$ 2,874,240	0.00%	$ -	$ -	0.00%	$ -	$ -
2	Structures & Improvements	39000	13,168,087		13,168,087	9.10%	1,198,296		3.34%	439,814	
3	Improv. to Leased Premises	39009	4,437,465		4,437,465	9.10%	403,809		4.06%	180,161	
4	Office Furniture & Equipment	39100	1,054,834		1,054,834	2.13%	22,468		4.03%	42,510	
5	Communication Equipment	39700	26,143,741		26,143,741	8.45%	2,209,146		5.54%	1,448,363	
6	Miscellaneous Equipment	39800	9,533		9,533	8.15%	777		1.72%	164	
7	Other Tangible Property	39900	-		0	4.66%	-		13.84%	-	
8	Oth Tang Prop Servers H/W	39901	13,047,889		13,047,889	6.95%	906,828		8.62%	1,124,728	
9	Oth Tang Prop Servers S/W	39902	7,582,366		7,582,366	4.00%	303,295		8.78%	665,732	
10	Oth Tang Prop Network H/W	39903	913,069		913,069	9.30%	84,915		8.72%	79,620	
11	Oth Tang Prop PC Hardware [1]	39906	2,556,429		2,556,429	14.86%	379,885		8.78%	224,454	
12	Oth Tang Prop PC Software	39907	3,327,195		3,327,195	9.02%	300,113		6.64%	220,926	
13	Oth Tang Prop Appl Software	39908	93,618,084		93,618,084	11.11%	10,400,969		6.57%	6,150,708	
14	Oth Tang Prop Gen. Starup C	39924	23,172,326		23,172,326	15.89%	3,682,083		15.89%	3,682,083	
15											
16			$ 191,905,258	$ -	$ 191,905,258		$ 19,892,585	$ -	7.43%	$ 14,259,263	$ -
17											
18											
19											
20	General Plant										
21	Charles K. Vaughn Training Ctr										
22	CKV-Land & Land Rights	38910	$ 1,887,123	$ -	$ 1,887,123	0.00%	$ -	$ -	0.00%	$ -	$ -
23	CKV-Structures & Improvements	39010	10,400,518		10,400,518	9.10%	946,447		3.34%	347,377	
24	CKV-Communication Equipment	39710	271,621		271,621	8.45%	22,952		5.54%	15,048	
25	CKV-Other Tangible Property	39910	90,541		90,541	4.66%	4,219		13.84%	12,531	
26	CKV-Oth Tang Prop-PC Hardware	39916	194,015		194,015	14.86%	28,831		8.78%	17,035	
27	CKV-Oth Tang Prop-PC Software	39917	90,541		90,541	9.02%	8,167		6.64%	6,012	
28			$ 12,934,358	$ -	$ 12,934,358		$ 1,010,616	$ -		$ 398,002	$ -
29											
30											
31	Total SSU Customer Support (Ln 16+Ln 28)		$ 204,839,617	$ -	$ 204,839,617		$ 20,903,200	$ -		$ 14,657,265	$ -

Kansas Distribution System
Depreciation Adjustment
As of test period end September 30, 2011
Kansas Div 30

Line No.	Description	Property Type	Balance at 9/30/11	Adjustment to Per Books	Depreciable Plant	Current Depreciation Rates: Depreciation Rates	Current Depreciation Rates: Pro-Forma Depreciation Expense	Current Depreciation Rates: Pro-Forma Capitalized Depr Exp (1)	Recommended Depreciation Rates: Depreciation Rates*	Recommended Depreciation Rates: Pro-Forma Depreciation Expense	Recommended Depreciation Rates: Pro-Forma Capitalized Depr Exp (1)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Improv. to Leased Premises	390.9	$ 189,717	$ -	$ 189,717	10.00%	$ 18,972	$ -	10.00%	$ 18,972	$ -
2	Office Furniture & Equipment	391	291,889		291,889	8.44%	24,635		8.44%	24,635	
3	Tools, Shop, & Garage Equip.	394	255,608		255,608	16.57%	21,304	21,050	16.57%	21,304	21,050
4	Communication Equipment	397	225,803		225,803	8.45%	19,080		8.45%	19,080	
5	Miscellaneous Equipment	398	228,979		228,979	15.46%	35,400		15.46%	35,400	
6	Oth Tang Prop Servers H/W	399.1	331,037		331,037	21.81%	72,199		21.81%	72,199	
7	Oth Tang Prop Network H/W	399.3	388,980		388,980	15.55%	60,486		15.55%	60,486	
8	Oth Tang Prop PC Hardware	399.6	898,952		898,952	25.25%	226,985		25.25%	226,985	
9	Oth Tang Prop PC Software	399.7	82,220		82,220	25.70%	21,130		25.70%	21,130	
10											
11			$ 2,893,184	$ -	$ 2,893,184	17.29%	$ 500,193	$ 21,050	17.29%	$ 500,193	$ 21,050
12											
13											

14 * Depreciation Rates approved in Colorado Rate Case Docket No. 09AL-507G.
15
16 Notes;
17 [1] For vehicle & POE depreciation expense, a portion of it is capitalized & some or all of the remaining balance is moved to account 8740. what determines whether or not
18 the non- capitalized portion moves to 8740 or stays in 4030 is whether or not the expense hits the default cost center (0000) or a cost center. If it hits the default cost center
19 (0000), the non- capitalized portion stays in 4030. For vehicles the rate of capitalization is determined by which cost center the expense hits. If it hits the default cost center
20 (0000), the rate is the overall company rate. If it hits a cost center, the rate is the individual cost center rate. The rate of capitalization for POE for FY 2009 is a fixed 85%
21 regardless of the cost center it hits.
22 For the other capitalized depreciation categories: 39300, 39400 & 39500 the capitalization rate is based on the same as aboe. The only difference is that the balance
23 (non-capitalized portion) stays in 4030.

Source: See tab "Section 4 Plant"

Atmos Energy Corp - Kansas Distrib System
Depreciation Exp Sub Acct Analysis
for the 12 mths ended 9/30/11

FERC Account 4030 Deprec Expense

Line No.	(a) Sub Account	(b) Sub Acct Descrip	(c) DIV 79	(d) 81	(e) 86	(f) 2	(g) 12	(h) 30	(i) 80	(j) Grand Total	(k) Percent Capitalized	(l) Percent Capitalized	(m) Percent Capitalized
1	9344	Depr & Taxes Other Expense	$ 14,287	$ 291,042	$ 16,442	$ -	$ -	$ (584,507)	$ 0	$ (262,736)			
2	30003	Depr Exp-Underground Storage	212,101							212,101			
3	30004	Depr Exp-Transmission Plant		30,743	35,435					66,178			
4	30005	Depr Exp-Distribution Plant		6,692,730	458,241					7,150,971			
5	30007	Depr Exp-General Plant	566	359,255	6,525	14,358,418	15,932,022	563,203		31,219,989			
6	30031	Vehicle Depreciation (392)		43,695	641	10,325				54,661	Div81	Div86	
7	30032	Vehicle Depreciation Capitalized (392)		(39,464)	(641)					(40,106)	-90.32%	-100.00%	
8	30041	Heavy Equipment Depreciation (396)		106,048	10,875					116,923	Div81	Div86	
9	30042	Heavy Equipment Depreciation Capitalized (396)		(103,927)	(10,658)					(114,585)	-98.00%	-98.00%	
10	30051	Stores Depreciation (393)		103						103	Div81		
11	30052	Stores Depreciation Capitalized (393)		(51)						(51)	-49.70%		
12	30061	Tools & Shop Depreciation (394)		144,408	9,804	8,473		42,354		205,040	Div81	Div86	Div30
13	30062	Tools & Shop Depreciation Capitalized (394)		(71,810)	(4,885)			(21,050)		(97,745)	-49.73%	-49.83%	-49.70%
14	30071	Lab Depreciation (395)		268						268	Div81		
15	30072	Lab Depreciation Capitalized (395)		(133)						(133)	-49.69%		
16	40001	Billed to West Tex Div				(1,098,542)	(1,317,776)			(2,416,318)			
17	40002	Billed to CO/KS Div				(921,012)	(1,224,933)			(2,145,945)			
18	40003	Billed to LA Div				(1,238,111)	(1,662,977)			(2,901,088)			
19	40004	Billed to Mid St Div				(2,031,487)	(2,218,089)			(4,249,577)			
20	40008	Billed to Mid-Tex Div				(5,492,667)	(8,269,474)			(13,762,141)			
21	40009	Billed to MS Div				(987,334)	(1,238,772)			(2,226,106)			
22	40010	Billed to Atmos Pipeline Div				(2,095,769)				(2,095,769)			
23	41124	Billing for Taxes Other and Depr				(512,294)			703,996	191,702			
24	41129	Billing for CSC Depr & Taxes Other		429,176	17,046				0	446,221			
25	41130	Billing for SS Depr & Taxes Other	31,257	636,764	35,974				(703,996)	-			
26	Grand Total		$ 258,211	$ 8,518,847	$ 574,799	$ 0	$ 0	$ 0	$ -	$ 9,351,857			

27

28 Note:

29

30 [1] For vehicle & POE depreciation expense, a portion of it is capitalized & some or all of the remaining balance is moved to account 8740. What determines whether or not the non-capitalized portion moves to 8740 or stays
31 in 4030 is whether or not the expense hits the default cost center (0000) or a cost center. If it hits the default cost center (0000), the non-capitalized portion stays in 4030. For vehicles the rate of capitalization is determined
32 by which cost center the expense hits. If it hits the default cost center (0000), the rate is the overall company rate. If it hits a cost center, the rate is the individual cost center rate. The rate of capitalization for POE for
33 FY2009 is a fixed 85% regardless of the cost center it hits.

For the other capitalized depreciation categories: 39300, 39400 & 39500 the capitalization rate is based on the same as above. The only difference is that the balance (non-capitalized portion) stays in 4030.

34

Source: See Relied 1t - Depr Exp Sub Acct

Atmos Energy Corporation - Kansas Distribution System
Taxes Other Than Income Taxes
Twelve Months Ended September 30, 2011 As Adjusted

Line No.	Description	Source	Liberty Div 79	Kansas Div 81	Southwest Div Div 86	Total Direct KS (c+d+e)	100.00% KS Admin 080DIV	Kansas Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Taxes Other Than Income Taxes, Acct 4081 Per Book								
1	FICA (01210)	WP 11-1	$ 3,625	$ 215,412	$ 16,233	$ 235,270	$ 28,043	$ 263,313	
2	Federal Unemployment (01211)	WP 11-1	62	3,802	291	4,155	428	4,583	
3	State Unemployment (01212)	WP 11-1	276	15,853	1,282	17,411	1,825	19,235	
4	FICA Accrual (01213)	WP 11-1	(18)	2,290	85	2,357	385	2,742	
5	FUTA Accrual (01214)	WP 11-1	0	9	1	10	1	11	
6	SUTA Accrual (01215)	WP 11-1	1	49	3	53	7	60	
7	Denver City Head Tax (01220)	WP 11-1	2	129	10	141	17	158	
8	Benefit Load Projects(01290)	WP 11-1	-	44,144	-	44,144	-	44,144	
9	Taxes Other Allocated (09344-5, 41124,29-30)	WP 11-1	224,200	4,665,710	261,940	5,151,850	(4,853,262)	298,588	
10	Ad Valorem accrual (30101)	WP 11-1	307,030	-	-	307,030	4,647,015	4,954,045	
11	Taxes Property and Other (30102)	WP 11-1	-	680,228	70,597	750,826	-	750,826	
12	Occupational License (30103)	WP 11-1	-	75	-	75	-	75	
13	Corp/State Franchise Tax (30105)	WP 11-1	-	-	-	-	20,000	20,000	
14	City Franchise (30107)	WP 11-1	-	1,944	-	1,944	-	1,944	
15	US DOT Pipe Safety funding (30108)	WP 11-1	-	-	-	-	-	-	
16	Public Srvc Comm Assessment (30112)	WP 11-1	-	-	-	-	155,541	155,541	
17									
18	Total Kansas Taxes Other Per Books		$ 535,178	$ 5,629,645	$ 350,442	$ 6,515,265	$ (0)	$ 6,515,265	
19									
20									
21	Adjustments								
22	KS Ad Valorem Adjustment - current	WP 11-2						$ 147,536	IS-8
23	KS Ad Valorem Adjustment - CWIP	WP 11-4						538,384	IS-9
24	Kansas Payroll Tax Adjustment	WP 11-5						69,574	IS-10
25	Public Srvc Comm Assessment Adj.	WP 11-6						(31,865)	IS-11
26	**Total Adjustments to Taxes Other than Income Taxes**							**$ 723,629**	
27									
28	**Total Taxes Other for KS Jurisdiction, Adjusted**							**$ 7,238,894**	

Atmos Energy Corp. - Kansas
Taxes Other Than Income Taxes, Acct. 4081, per books
Twelve Months Ended September 30, 2011

Line No.	(a) Sub Account	(b) Sub Acct Descrip	(c) DIV 79	(d) DIV 81	(e) DIV 86	(f) DIV 2	(g) DIV 12	(h) DIV 30	(i) DIV 80	(j) Grand Total
1	1200	Benefits Load	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	1210	Fica Load	3,625	215,412	16,233	2,609,425	1,991,791	75,369	28,043	4,939,897
3	1211	Futa Load	62	3,802	291	34,261	26,295	1,130	428	66,269
4	1212	Suta Load	276	15,853	1,282	78,282	59,972	4,667	1,825	162,157
5	1213	Fica Load Accrual	(18)	2,290	85	12,882	962	259	385	16,844
6	1214	Futa Load Accrual	0	9	1	(38)	(46)	3	1	(70)
7	1215	Suta Load Accrual	1	49	3	(100)	(113)	17	7	(136)
8	1220	Denver City Tax Load	2	129	10	17	13	45	17	234
9	1290	Benefit Load Projects		44,144		2,698		(8)		46,834
10	9344	Taxes other								-
11	9345	Taxes other than inc tax	224,200	4,567,324	258,032			(120,084)	(4,983,450)	(53,978)
12	30101	Ad Valorem - Accrual	307,030			688,122	435,229	38,602	4,647,015	6,115,998
13	30102	Taxes Property and Other		680,228	70,597	31,930				782,756
14	30103	Occupational Licenses		75						75
15	30105	Corp/State Franchise Tax							20,000	20,000
16	30107	City Franchise		1,944						1,944
17	30108	Dot Transmission User Tax								-
18	30112	Public Service Comm							155,541	155,541
19	40001	Billed to Tex Div				(273,141)	(235,823)			(508,964)
20	40002	Billed to CO/KS Div				(236,492)	(193,334)			(429,826)
21	40003	Billed to LA Div				(334,684)	(272,780)			(607,464)
22	40004	Billed to Mid St Div				(507,212)	(369,824)			(877,037)
23	40005	Billed to KY Div								-
24	40007	Billed to Nonutilities				(118,937)				(118,937)
25	40008	Billed to Mid-Tex Div				(1,326,980)	(1,243,224)			(2,570,204)
26	40009	Billed to MS Div				(261,385)	(199,117)			(460,502)
27	40010	Billed to Atmos Pipeline Div				(398,647)				(398,647)
28	41124	Billing for taxes other						236,492		236,492
29	41129	Billing for CSC Depr & Taxes Other		98,386	3,908			(0)		102,293
30	41130	Billing for SS Depr & Taxes Other						(236,492)	130,189	(106,303)
31	Grand Total 4081 Per Book		$ 535,178	$ 5,629,645	$ 350,442	$ 0	$ 0	$ (0)	$ (0)	$ 6,515,265
32										
33										
34	Summary components of Per Book Taxes Other than Income Taxes:									
35		Direct Tax	$ 310,977	$ 963,935	$ 88,502	$ 3,457,479	$ 2,514,102	$ 120,084	$ 4,853,262	
36		Taxes allocated in	224,200	4,665,710	261,940	-	-	236,492	130,189	
37		Taxes allocated out	-	-	-	(3,457,479)	(2,514,102)	(356,576)	(4,983,450)	
38	**Grand Total 4081 Per Book**		$ 535,178	$ 5,629,645	$ 350,442	$ -	$ 0	$ (0)	$ (0)	$ 6,515,265

Source: See Relied File 1h

Atmos Energy Corp
Kansas AdValorem Tax Adjustment
Adjust Tax Expense to most Current Tax Assessed

Line No.	(a)	(b)	(c) Actual Tax Assessment CY11	(d) Less Annual Capitalized	(e) Net Assessment	
			Proforma KS direct Ad Valorem Tax Exp and Adjustment			
1		Div 79 Liberty	$ 357,323	$ -	$ 357,323	
2		Div 80 Admin	5,495,316	(89,711)	5,405,605	
3			$ 5,852,639	$ (89,711)	$ 5,762,928	
4						
5	Test Year Ad-Valorem Expense Per Book 4081.30101: Only Div 79			WP 11-3	$ 5,615,392	
6						
7	Difference to Adjust Per Book Ad Valorem Expense to CY11 Assessment				$ 147,536	**IS-8**

Source: See Relied file 9

WP 11-3

Atmos Energy Corp
Total Kansas Direct Ad Valorem Summary, 4081.30101 per bk
For the 12 months ended 9/30/11

Line	(a)	(b)	(c)	(d)	(e)		(f)
		Kansas Direct Ad Valorem Tax Exp, Div 79, 80, 81, 86					
		4081.30101 DR Gross Exp Accrual	4081.30101 CR Less Capitalized Power Plant	4081.30101 CR Less Reg Asset 1823 DR	4081.30101 DR Plus Surcharge Banner	4081.30102 DR Ad Valorem Surcharge	Total 4081 Net Expense
1	Div 79 Liberty	$ 586,556	$0	$ (66,628)	$ -	$ -	$ 519,928
2	Div 80 Admin	5,459,517	(89,711)	(938,397)	0	0	4,431,409
3	Div 81 KS	0	0	0	0	593,458	593,458
4	Div 86 SW	0	0	0	0	70,597	70,597
5	Test Year	$ 6,046,073	$ (89,711)	$ (1,005,025)	$ -	$ 664,056	$ 5,615,392
6							
7	**Kansas Direct Ad Valorem Tax by Division:**						
8							
9		KS Liberty Div 79 Ad Valorem Summary					
10		4081 DR	4081 CR	4081 CR	4081 DR	4081.30102 DR	Total
11		Gross Exp	Less Capitalized	Less Reg Asset	Plus Surcharge	Ad Valorem	4081.30101
12		Accrual	Power Plant	1823 DR	Banner	Surcharge	Net Expense
13	Oct-10	$ 43,299	$0	$ (5,315)	$ -	$ -	$ 37,984
14	Nov-10	43,299	-	(5,315)	-		37,984
15	Dec-10	71,855	-	0	-		71,855
16	Jan-11	47,567	-	(6,222)	-		41,345
17	Feb-11	47,567	-	(6,222)	-		41,345
18	Mar-11	47,567	-	(6,222)	-		41,345
19	Apr-11	47,567	-	(6,222)	-		41,345
20	May-11	47,567	-	(6,222)	-		41,345
21	Jun-11	47,567	-	(6,222)	-		41,345
22	Jul-11	47,567	-	(6,222)	-		41,345
23	Aug-11	47,567	-	(6,222)	-		41,345
24	Sep-11	47,567	-	(6,222)	-		41,345
25	Test Year	$ 586,556	$ -	$ (66,628)	$ -	$ -	$ 519,928
26							
27		Admin Div 80 Ad Valorem Summary					
28		4081 DR	4081 CR	4081 CR	4081 DR	4081.30102 DR	Total
29		Gross Exp	Less Capitalized	Less Reg Asset	Plus Surcharge	Ad Valorem	4081.30101
30		Accrual	Power Plant	1823 DR	Banner	Surcharge	Net Expense
31	Oct-10	$ 389,697	$ (7,438)	$ (47,831)	$ -	$ -	$ 334,428
32	Nov-10	389,697	(7,438)	(47,831)	-		334,428
33	Dec-10	827,151	(7,438)	(338,699)	-		481,014
34	Jan-11	428,108	(7,438)	(56,004)	-		364,666
35	Feb-11	428,108	(7,438)	(56,004)	-		364,666
36	Mar-11	428,108	(7,438)	(56,004)	-		364,666
37	Apr-11	428,108	(7,438)	(56,004)	-		364,666
38	May-11	428,108	(7,529)	(56,004)	-		364,575
39	Jun-11	428,108	(7,529)	(56,004)	-		364,575
40	Jul-11	428,108	(7,529)	(56,004)	-		364,575
41	Aug-11	428,108	(7,529)	(56,004)	-		364,575
42	Sep-11	428,108	(7,529)	(56,004)	-		364,575
43	Test Year	$ 5,459,517	$ (89,711)	$ (938,397)	$ -	$ -	$ 4,431,409
44							
45							
46		Div 81 Ad Valorem Summary					
47		4081 DR	4081 CR	4081 CR	4081 DR	4081.30102 DR	Total
48		Gross Exp	Less Capitalized	Less Reg Asset	Plus Surcharge	Ad Valorem	4081.30101
49		Accrual	Power Plant	1823 DR	Banner	Surcharge	Net Expense
50	Oct-10	$ -	$ -	$ -	$ -	$ 8,109	$ 8,109
51	Nov-10	-	-	-	0	17,670	17,670
52	Dec-10	-	-	-	0	50,929	50,929
53	Jan-11	-	-	-	0	134,278	134,278
54	Feb-11	-	-	-	0	144,135	144,135
55	Mar-11	-	-	-	0	98,714	98,714
56	Apr-11	-	-	-	0	56,521	56,521
57	May-11	-	-	-	0	29,896	29,896
58	Jun-11	-	-	-	0	16,889	16,889
59	Jul-11	-	-	-	0	12,279	12,279
60	Aug-11	-	-	-	0	11,355	11,355
61	Sep-11	-	-	-	0	12,685	12,685
62	Test Year	$ -	$ -	$ -	$ -	$ 593,458	$ 593,458
63							
64		Div 86 Ad Valorem Summary					
65		4081 DR	4081 CR	4081 CR	4081 DR	4081.30102 DR	Total
66		Gross Exp	Less Capitalized	Less Reg Asset	Plus Surcharge	Ad Valorem	4081.30101
67		Accrual	Power Plant	1823 DR	Banner	Surcharge	Net Expense
68	Oct-10	$ -	$ -	$ -	$ -	$ 2,055	$ 2,055
69	Nov-10	-	-	-	0	2,634	2,634
70	Dec-10	-	-	-	0	3,121	3,121
71	Jan-11	-	-	-	0	5,916	5,916
72	Feb-11	-	-	-	0	5,949	5,949
73	Mar-11	-	-	-	0	7,022	7,022
74	Apr-11	-	-	-	0	8,157	8,157
75	May-11	-	-	-	0	6,554	6,554
76	Jun-11	-	-	-	0	6,906	6,906
77	Jul-11	-	-	-	0	8,534	8,534
78	Aug-11	-	-	-	0	7,900	7,900
79	Sep-11	-	-	-	0	5,849	5,849
80	Test Year	$ -	$ -	$ -	$ -	$ 70,597	$ 70,597

Atmos Energy Corp
Kansas Ad Valorem Tax Adjustment
Adjust Proforma Ad valorem Tax Expense for Construction Work in Progress
For Kansas Direct Divs 79, 80, 81, 86

Line	(a) Description	(b) Total KS Direct	(c) Source
1	Per Book Direct Kansas CWIP	$ 5,128,202	Wp 14-1-1
2	Adjustment to CWIP	18,403,631	Wp 14-1-2
3	Adjusted Direct CWIP 9/30/11	$ 23,531,833	
4	KS Ad Valorem Expense as % of Plant	2.29%	Line 12
5			
6	Adjust Ad Valorem Expense for CWIP	$ 538,384	**IS-9**
7			
8		Total KS Direct	
9	Annual Kansas Ad Valorem Tax Expense Assessed	$ 5,762,928	WP 11-2
10	Test Year KS Direct Gross Plant	$ 251,887,570	Section 4
11			
12	Ad Valorem Tax Expense as % of Gross Plant	2.29%	Ln 9 / Ln 10

Atmos Energy Corp - Kansas Distribution System
Kansas Payroll Tax Adjustment
for the test year ended September 30, 2011

Adjust Payroll Tax Expense to synchronize with Labor Adjustment

Line No.	Description	Source	Liberty Div 79	Kansas Div 81	Southwest Div Div 86	Total Direct KS (c+d+e)	100.00% KS Admin 080DIV	Kansas Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Payroll Tax Adjustment Calculation (Exclude General Office):								
1	Gross Direct Labor w/ Annualized merit increase	**WP 9-2**	$ 58,319	$ 8,115,894	$ 343,512	$ 8,517,725	$ 725,121	$ 9,242,846	
2	3 Yr Average Expense Rate	**WP 9-2-2**	54.61%	54.61%	54.61%		54.61%		
3									
4	Kansas Direct Proforma Labor Expense		$ 31,849	$ 4,432,291	$ 187,600	$ 4,651,740	$ 396,007	$ 5,047,747	
5	Normalized Payroll Tax Rate - FY12 Budget	**8.00%**	2,548	354,583	15,008	372,139	31,681	403,820	
6	Less Per Book Kansas Direct Payroll Tax (Lines 1-8)	**Section 11**	(3,947)	(281,688)	(17,905)	(303,540)	(30,706)	(334,245)	
7									
8	Adjustment		$ (1,399)	$ 72,896	$ (2,897)	$ 68,600	$ 975	$ 69,574	**IS-10**

Atmos Energy Corp - Kansas Distribution System
Kansas CC Assessment Adjustment - 4081.30112

Adjust Tax Expense to current KCC fees paid, proforma 12 months September 30, 201

Line No.	(a) Month/Year		(b) Div 80 KCC Fee Paid & Expense	
1	Oct-10	$	44,150	
2	Nov-10		-	
3	Dec-10		14,292	
4	Jan-11		31,626	
5	Feb-11		-	
6	Mar-11		3,830	
7	Apr-11		32,020	
8	May-11		1,888	
9	Jun-11		-	
10	Jul-11		-	
11	Aug-11		27,736	
12	Sep-11		-	
13	**Test Year**	**$**	**155,541**	
14				
15	Oct-11	$	-	
16	Nov-11		-	
17	Dec-11		26,576	
18	**12 months Dec11**	**$**	**123,676**	
19				
20	**Adjustment**	**$**	**(31,865)**	**IS-11**

Source: See Relied 10

Kansas Distribution System
Computation of Income Taxes
Twelve Months Ended September 30, 2011, As Adjusted

Line No.	Description	Source		Total
	(a)	(b)		(c)
	Per Books:			
1	Required Return	Section 3A	$	12,739,229
2	Interest Deduction	WP 11B		4,572,200
3	Equity Portion of Return		$	8,167,029
4	Application of Composite Tax Rate to NIBT		$	3,232,714
5	Allowance for Step Rate			(1,525)
6	Sub-Total		$	3,231,189
7	Tax Expansion Factor			1.6551
8	Total Income Tax Liability		$	5,348,102
9				
10	**After Adjustments:**			
11	Required Return	Section 3A	$	14,060,342
12	Interest Deduction	WP 11B		5,046,357
13	Equity Portion of Return		$	9,013,985
14	Application of Composite Tax Rate to NIBT		$	3,567,961
15	Allowance for Step Rate			(1,525)
16	Sub-Total		$	3,566,436
17	Tax Expansion Factor			1.6551
18	Total Income Tax Liability		$	5,902,984
19				
20		Income Tax Adjustment	$	554,883 **IS-12**
21				
22				
23	State Tax Rate	7.05%		
24	Federal Tax Rate	35%		
25	Combined Tax Rate	39.583%		

Source: See Relied file 11b - (Provided in response to DR 1)

Atmos Energy Corporation
Kansas Distribution System
Computation of Pro-forma Interest Expense, LT Debt
Test Year Twelve Months Ended September 30, 2011

Line No.	Description	Source	Total KS
	(a)	(b)	(c)
1	Rate Base (before Adjustments)	Section 3	$ 145,033,986
2	Debt Percentage of Capital Structure	Section 7	48.34%
3			
4	Debt portion of Rate Base		$ 70,107,117
5	Long Term Debt rate	Section 7	6.52%
6			
7	Interest Expense, LT Debt		$ 4,572,200
8			
9	Rate Base Adjusted	Section 3	$ 160,074,634
10	Debt Percentage of Capital Structure	Section 7	48.34%
11			
12	Debt portion of Rate Base		$ 77,377,526
13	Long Term Debt rate	Section 7	6.52%
14			
15	Interest Expense, LT Debt		$ 5,046,357

Kansas Distribution System
Computation of Federal Income Taxes
Twelve Months Ended September 30, 2009, As Adjusted

Line No.	Description	Source	Total
	(a)	(b)	(c)
1	Income Taxes - Current		$ 4,148,693
2	Income Taxes - Deferred		1,754,292
3	Total Income Tax Expense	**Section 11B**	$ 5,902,984
4			
5			
6	ADIT Balances:		
7	9/30/2010	**WP 11E-1**	$ (37,012,916)
8	9/30/2011	**WP 14-4**	(38,767,208)
9	Change		$ 1,754,292

Kansas Distribution System
Schedule of Income Tax Credits
Twelve Months Ended September 30, 2011

Line No.	Description	Beginning Balance	Activity	Ending Balance
	(a)	(b)	(c)	(d)
1	1997	$ 811,501	$ (6,654)	$ 804,847
2	1998	804,847	(122,383)	682,464
3	1999	682,464	(61,737)	620,727
4	2000	620,727	210,465	831,192
5	2001	831,192	(508,459)	322,733
6	2002	322,733	329,913	652,646
7	2003	652,646	(88,912)	563,734
8	2004	563,734	(88,912)	474,822
9	2005	474,822	(88,912)	385,910
10	2006	385,910	(88,912)	296,998
11	2007	296,998	(88,912)	208,086
12	2008	208,086	(88,912)	119,174
13	2009	119,174	(88,912)	30,262
14	2010	30,262	(26,624)	3,638
15	2011	3,638	(3,360)	278
16				
17	Kansas Total at September 30, 2010			$ 2,119
18				
19	Kansas Total at September 30, 2011			$ 162
20				
21				
22	[1] Data is presented as of the end of the			
23	Company's fiscal year ending September 30.			

Source: See Relied file 11 d - (Provided in response to DR 1)

Kansas Distribution System
Schedule of Deferred Income Taxes
Twelve Months Ended September 30, 2011

Line No.	Description	Beginning Balance	Activity	Ending Balance
	(a)	(b)	(c)	(d)
	Atmos Energy Corporation [1] (in 000's)			
1	1997	$ 72,073	$ 15,755	$ 87,828
2	1998	87,828	(7,092)	80,736
3	1999	80,736	31,939	112,675
4	2000	112,675	18,944	131,619
5	2001	131,619	7,315	138,934
6	2002	138,934	(4,395)	134,540
7	2003	134,540	88,810	223,350
8	2004	223,350	(9,419)	213,931
9	2005	213,931	10,912	224,842
10	2006	224,842	62,387	287,229
11	2007	287,229	78,675	365,905
12	2008	365,905	77,230	443,135
13	2009	443,135	136,859	579,994
14	2010	579,994	195,208	775,202
15	2011	775,202	108,167	883,368
16				
17				
18	Kansas Total at September 30, 2010		WP 11E-1	$37,012,916
19				
20	Kansas Total at September 30, 2011		WP 14-4	$38,767,208
21				
22				
23	[1] Data is presented as of the end of the			
24	Company's fiscal year ending September 30.			

Source: See Relied file 11 e

Kansas Distribution System
Computation of Deferred Income Taxes
Twelve Months Ended September 30, 2011

Line No.	Description	CO/KS GO	KS Admin	SSU	CSC	Allocated CO/KS GO	Allocated SSU	Allocated CSC	Allocated Direct KS	Total Allocated and Direct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Deferred Income Taxes September 30, 2011									
2	190	$ 6,588,588	$ -	$ 124,358,694	$ (1,115,152)	$ 3,837,194	$ 5,061,399	$ (46,502)	$ (43,425)	$ 8,808,666
3	282	(1,248,418)	0	(22,081,076)	(18,407,536)	($727,078)	($898,700)	($767,594)	($40,137,946)	($42,531,319)
4	283	417,808	0	(23,376,182)	(100,295)	243,331	($951,411)	($4,182)	($2,578,002)	($3,290,263)
5										
6	Total	$ 5,757,978	$ -	$ 78,901,436	$ (19,622,982)	$ 3,353,447	$ 3,211,288	$ (818,278)	$ (42,759,373)	$ (37,012,916)

Source: See Relied file 11E-1 Comp of Def Inc Tax

Atmos Energy Corporation
Development of Allocation Factors
For Fiscal Year 2012

Line No.	Div # (a)	Division Name (b)	Gross Direct PP&E (c)	Percent of PP&E (d)	Direct O&M (e)	Percent of O&M (f)	Avg Number of Customers (g)	Percent of Customers (h)	Average Allocation Percentage (i)
1		**Shared Services Div 02 - Regulated Only Allocation to Business Units (Div 12 Customer Support uses col h customer factors)**							
2		West Texas Division	$ 475,799,544	6.98%	$ 26,322,771	8.25%	$ 296,271	9.63%	8.27%
3		Colorado-Kansas Division	435,237,882	6.38%	23,607,153	7.40%	239,561	7.78%	7.19%
4		Louisiana Division - Svc Area 007	171,586,570	2.52%	8,173,008	2.56%	73,476	2.39%	2.49%
5		Louisiana Division - Svc Area 077	478,057,194	7.01%	22,635,485	7.09%	268,964	8.74%	7.62%
6		Kentucky/Mid-States Division	975,794,120	14.31%	41,833,253	13.11%	386,579	12.56%	13.33%
7		Mississippi Division	405,643,172	5.95%	31,181,155	9.77%	249,423	8.10%	7.94%
8		Mid-Tex Division	2,700,636,005	39.59%	102,246,684	32.05%	1,563,138	50.79%	40.81%
9		Atmos Pipeline - Texas Division	1,178,089,218	17.27%	63,036,059	19.76%	350	0.01%	12.35%
10			$6,820,843,704	100.00%	$319,035,568	100.00%	$ 3,077,762	100.00%	100.00%
11									
12		**Shared Services - Consolidated Allocation to Business Units (Div 12 Customer Support uses col h customer factors)**							
13		West Texas Division	$ 475,799,544	6.90%	$ 26,322,771	7.67%	$ 296,271	9.62%	8.07%
14		Colorado-Kansas Division	435,237,882	6.31%	23,607,153	6.88%	239,561	7.78%	6.99%
15		Louisiana Division - Svc Area 007	171,586,570	2.49%	8,173,008	2.38%	73,476	2.39%	2.42%
16		Louisiana Division - Svc Area 077	478,057,194	6.93%	22,635,485	6.60%	268,964	8.74%	7.42%
17		Kentucky/Mid-States Division	975,794,120	14.14%	41,833,253	12.19%	386,579	12.56%	12.96%
18		Mississippi Division	405,643,172	5.88%	31,181,155	9.09%	249,423	8.10%	7.69%
19		Mid-Tex Division	2,700,636,005	39.14%	102,246,684	29.80%	1,563,138	50.77%	39.90%
20		Atmos Pipeline - Texas Division	1,178,089,218	17.07%	63,036,059	18.37%	350	0.01%	11.82%
21		Non-Regulated Operations	79,205,240	1.15%	24,030,867	7.00%	1,115	0.04%	2.72%
22			$6,900,048,944	100.00%	$343,066,436	100.00%	$ 3,078,877	100.00%	100.00%
23									
24		**Colorado/Kansas General Office Div 30 Allocation to states Colorado, Kansas, Missouri**							
25	29+71	Missouri	$ -	0.00%	$ -	0.00%	$ -	0.00%	0.00%
26	33 - 41	Colorado	180,449,076	41.74%	5,700,396	37.17%	111,061	46.36%	41.76%
27	30	Kansas	251,895,622	58.26%	9,635,622	62.83%	128,500	53.64%	58.24%
28		Total	$ 432,344,698	100.00%	$ 15,336,018	100.00%	$ 239,561	100.00%	100.00%
29									
30		**Kansas Admin Office Div 80 Allocation to Kansas Divisions**							
31		Total	$ 251,895,622	97.64%	$ 9,635,622	89.96%	$ 128,500	100.00%	100.00%
32									
33		**Shared Services Div 02 Allocation to Kansas Divisions (Div 12 Customer Support uses col h customer factors)**							
34		Total						4.17%	4.07%
35									

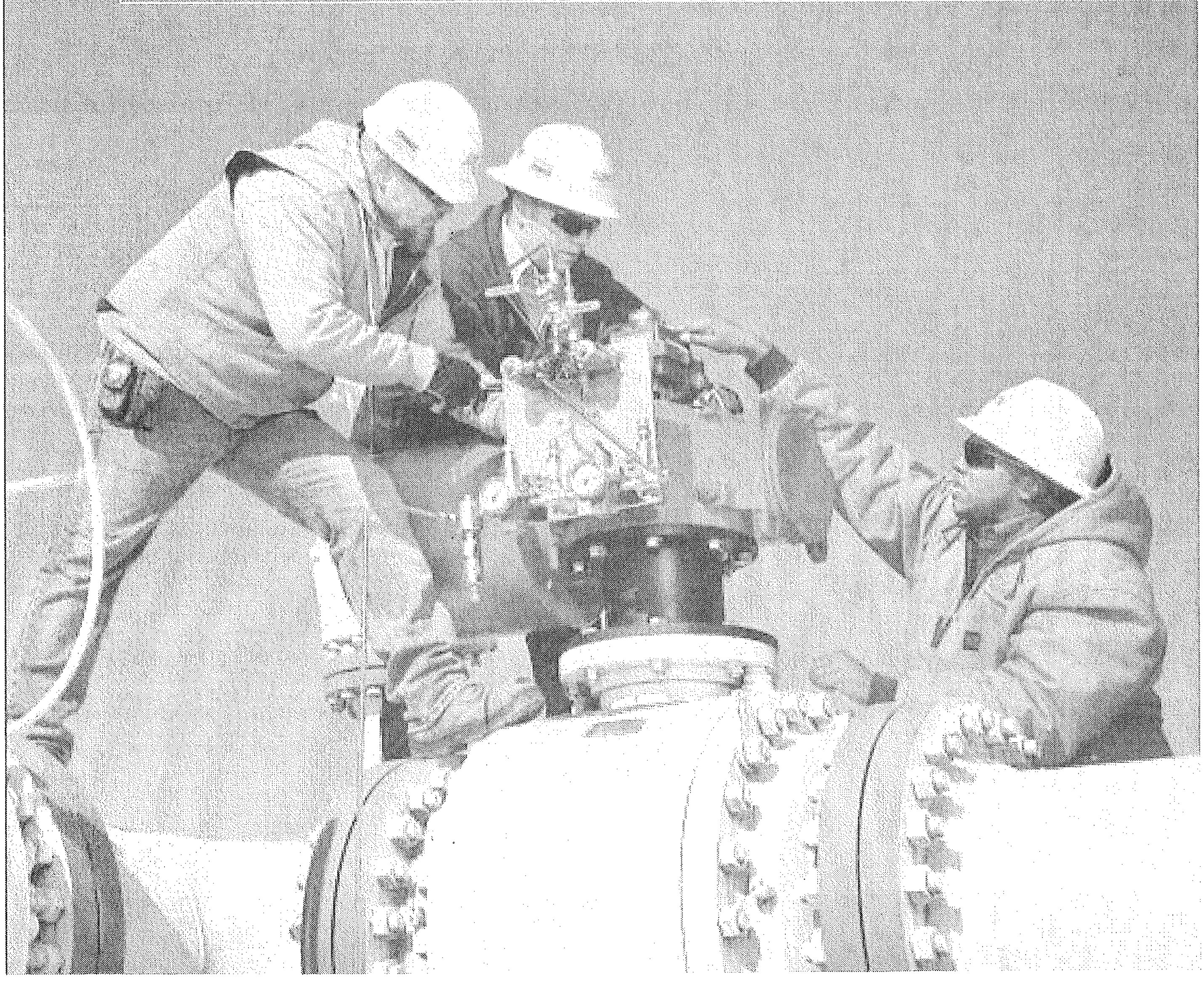
Source: See Relied File 12

Atmos Energy Corporation 2011 Summary Annual Report

Ensuring Safety
and Reliability

ATMOS
energy

Voices for Safety



Graham Landell Perry

Senior Engineer

Dallas, TX

"I'm involved in the design of natural gas pipelines, measurement stations and regulator stations," explains Senior Engineer Landell Perry. "Our design of new state-of-the-art instrumentation and controls allows Atmos Energy to know immediately if there's a pressure spike and shut a line down remotely. Our goal as engineers is to find effective and efficient solutions to help protect our customers and deliver highly reliable natural gas transmission and distribution service."

As engineers, it's our duty to design the most effective solutions for our customers and communities.

Cover: Mid-Tex Division Senior Engineer Landell Perry (right), Field Construction Coordinator Robert Parker and Crew Leader Royce Sharp inspect the installation of an actuator on an existing remote control valve for an Atmos Pipeline - Texas transmission line.

Above: The work involves close cooperation among teams from engineering and pipeline operations.

Natural gas pipelines span 2.4 million miles across the United States — an extensive network that delivers the efficient, clean and abundant fuel we all rely on for economic strength and national security. In the Atmos Energy system alone, our employees are responsible for about 77,000 miles of natural gas pipelines, serving more than 1,600 communities of all sizes in 12 states.

Ensuring safety and reliability of our gas transmission and distribution infrastructure stands as our highest goal.

Our team understands the requirements of pipeline safety, and they diligently carry out our policies and programs to maintain and modernize our pipeline network. They work to protect our customers, our employees, the public and our underground pipeline assets at all times.

In this report, 11 of our employees share how their attitudes and actions contribute to a culture of safety. These are our voices for safety — and they speak for the nearly 5,000 Atmos Energy team members who serve our customers and communities every day.

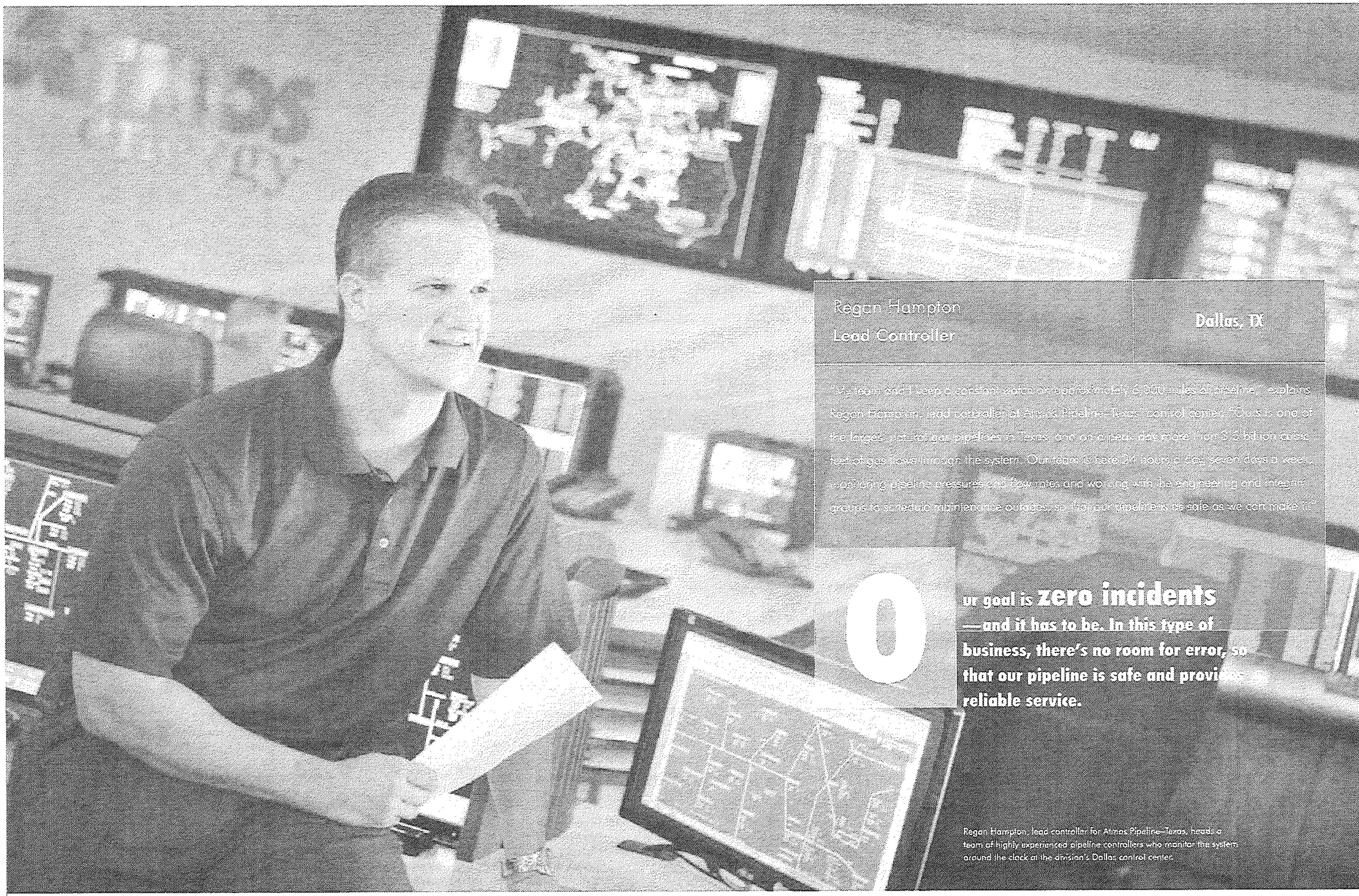
Danny Waguespack
Compliance Manager

Metairie, LA

"All states have pipeline safety requirements that go beyond the federal regulations," says Compliance Manager Danny Waguespack. "Compliance is responsible for making sure we meet or exceed the highest standard in each state we serve. Those codes include Operator Qualification, Pipeline Integrity Management, Public Awareness, Damage Prevention, Distribution Integrity Management, Control Room Management and more. The compliance world is always evolving and ever changing."

We don't just follow the letter of the law; we follow the spirit of the law. We're constantly reviewing every aspect of our operations. If we see a better way of doing things, we pursue it.

Louisiana Division Compliance Manager Danny Waguespack (left) and Survey Specialist Billy Daniel check the placement of required warning signs along one of the company's rights-of-way to alert the public to a buried pipeline and help prevent damage to it from excavation.



Regan Hampton
Lead Controller

Dallas, TX

"My team and I keep a constant watch on approximately 6,000 miles of pipeline," explains Regan Hampton, lead controller at Atmos Pipeline–Texas' control center. "Ours is one of the largest natural gas pipelines in Texas, and on a peak day more than 5.2 billion cubic feet of gas flows through the system. Our team is here 24 hours a day, seven days a week, monitoring pipeline pressures and flow rates and working with the engineering and integrity groups to schedule maintenance outages, so that our pipeline is as safe as we can make it."

Our goal is zero incidents—and it has to be. In this type of business, there's no room for error, so that our pipeline is safe and provides a reliable service.

Regan Hampton, lead controller for Atmos Pipeline–Texas, heads a team of highly experienced pipeline controllers who monitor the system around the clock at the division's Dallas control center.

Kenny Compton
Senior Service Technician

Radford, VA

We're out there to **protect life and property.** When we meet customers or go into their homes, safety is our No. 1 concern.

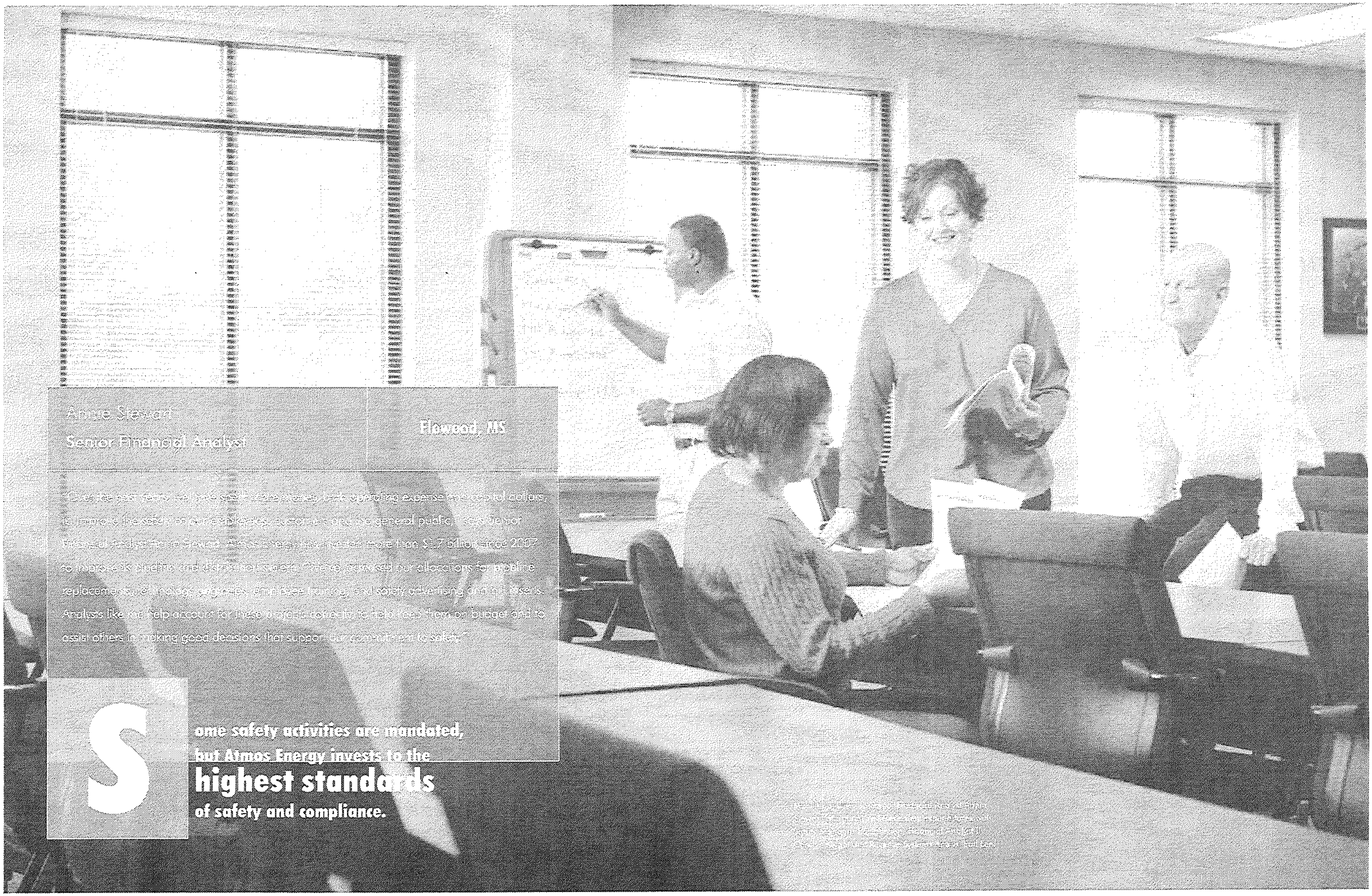
Senior Service Technician Kenny Compton in the Kentucky/Mid-States Division uses instruments to locate and mark a buried natural gas line to help prevent damage from excavation.

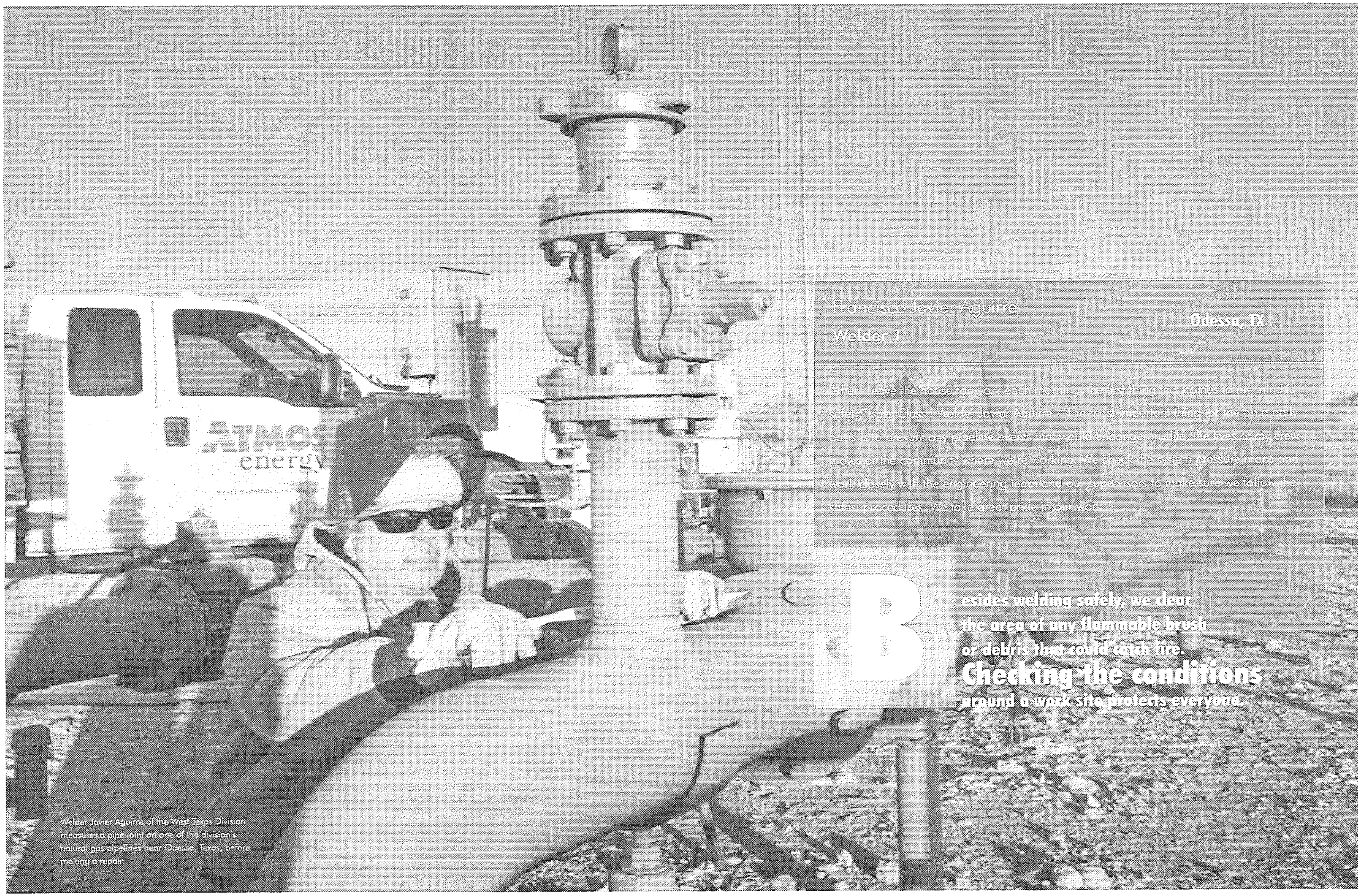
James Sparks
Corrosion Control Technician

Madisonville, KY

I have been at this more than 40 years—long enough to see that **our safety measures really work.**

Corrosion Control Technician James Sparks of the Kentucky/Mid-States Division, who is a recognized expert on cathodic protection, inspects our natural gas system in Kentucky.


Annie Stewart
Senior Financial Analyst
Flowood, MS
Some safety activities are mandated,
but Atmos Energy invests to the
highest standards
of safety and compliance.



Francisco Javier Aguirre
Welder 1

Odessa, TX

"When I leave the house for work each morning, the first thing that comes to my mind is safety," says Class I Welder Javier Aguirre. "The most important thing for me on a daily basis is to prevent any pipeline events that would endanger my life, the lives of my crewmates or the community where we're working. We check the system pressure maps and work closely with the engineering team and our supervisors to make sure we follow the safest procedures. We take great pride in our work."

Besides welding safely, we clear the area of any flammable brush or debris that could catch fire. Checking the conditions around a work site protects everyone.

Welder Javier Aguirre of the West Texas Division measures a pipe joint on one of the division's natural gas pipelines near Odessa, Texas, before making a repair.

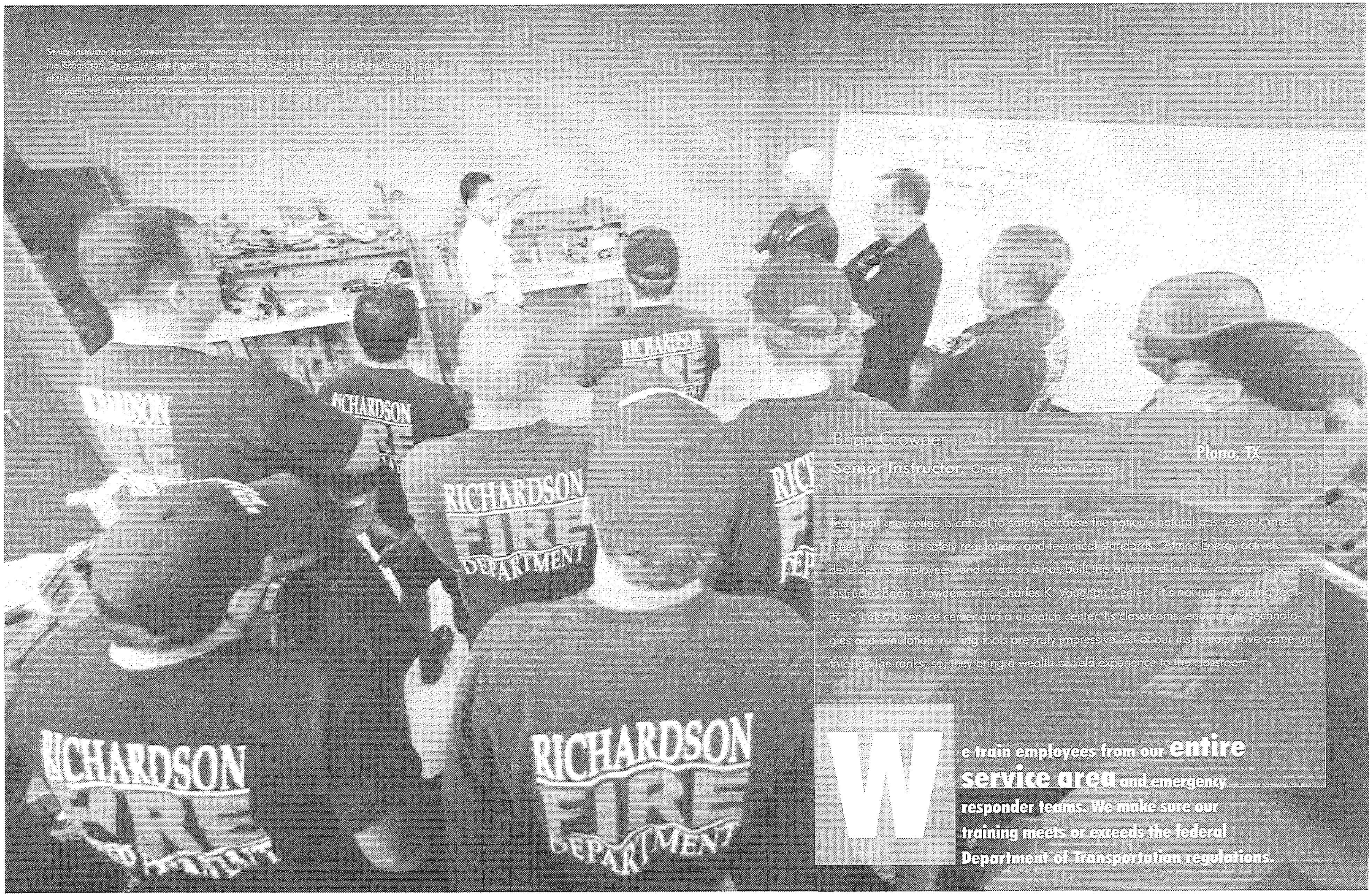
Annie Estrada
Customer Support Associate

Waco, TX

"We're trained in many areas of customer assistance but especially customer safety," says Annie Estrada, a customer support associate at Atmos Energy's Waco Customer Contact Center. "Emergency calls are definitely our top priority. When customers suspect a gas leak, we help them stay calm and ask questions to gather information for our responding technicians. Inside or outside? Backyard or front yard? Is it near the gas meter? We direct our customers where to go to be safe and dispatch crews immediately, using the information to help our technicians investigate the leak and make the area safe."

When it comes to safety, we are highly trained to keep our customers safe, identify where a leak might be and send trained technicians quickly to investigate.

Annie Estrada, customer support associate of Atmos Energy's Waco Customer Support Center, and Melissa Hutyra, senior administrative assistant, review the company's online information about safety.



Senior Instructor Brian Crowder discusses natural gas fundamentals with a team of firefighters from the Richardson, Texas, Fire Department at the company's Charles K. Vaughan Center. Although most of the center's trainees are company employees, the staff works closely with emergency responders and public officials as part of a close alliance that protects our communities.

Brian Crowder
Senior Instructor, Charles K. Vaughan Center

Plano, TX

Technical knowledge is critical to safety because the nation's natural gas network must meet hundreds of safety regulations and technical standards. "Atmos Energy actively develops its employees, and to do so it has built this advanced facility," comments Senior Instructor Brian Crowder at the Charles K. Vaughan Center. "It's not just a training facility; it's also a service center and a dispatch center. Its classrooms, equipment, technologies and simulation training tools are truly impressive. All of our instructors have come up through the ranks; so, they bring a wealth of field experience to the classroom."

We train employees from our entire service area and emergency responder teams. We make sure our training meets or exceeds the federal Department of Transportation regulations.

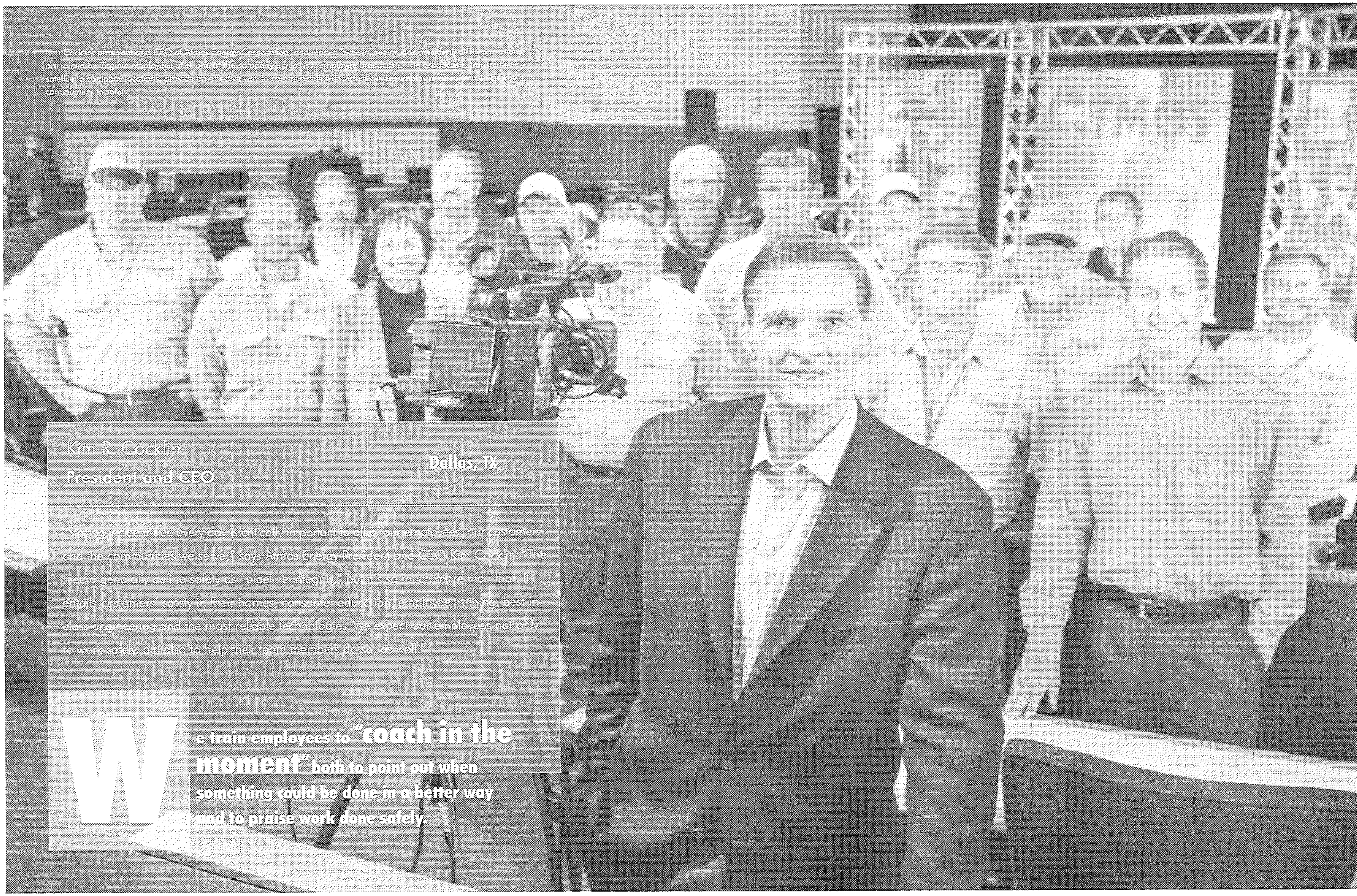
Brian Martens, Colorado manager of public affairs, [illegible]

Brian Martens
Manager of Public Affairs

Greeley, CO

"Besides working with public officials and the media, we visit schools to help students learn what this invisible thing, natural gas, is all about," says Manager of Public Affairs Brian Martens. "On the Internet, we have lesson plans for teachers, fun experiments and a challenge to create a project about energy efficiency and safety. The sixth-graders at Mountain View Core Knowledge Charter School in Cañon City, Colorado, wrote and filmed a skit showing energy traveling through a pipe, into a home and heating the house, water and food. It was terrific."

We help kids at school understand how natural gas works, what it smells like and what to do if they smell it.



Kim Cocklin, president and CEO of Atmos Energy Corporation, [illegible] commitment to safety.

Kim R. Cocklin

President and CEO

Dallas, TX

"Staying incident-free every day is critically important to all of our employees, our customers and the communities we serve," says Atmos Energy President and CEO Kim Cocklin. "The media generally define safety as 'pipeline integrity,' but it's so much more than that. It entails customers' safety in their homes, consumer education, employee training, best-in-class engineering and the most reliable technologies. We expect our employees not only to work safely, but also to help their team members do so, as well."

We train employees to "coach in the moment" both to point out when something could be done in a better way and to praise work done safely.

To Our Shareholders

Atmos Energy Corporation achieved substantial results in fiscal 2011. Our track record of creating shareholder value continued through consistent earnings-per-share growth. We also marked 28 years of consecutive annual dividend increases, after including all mergers and acquisitions.

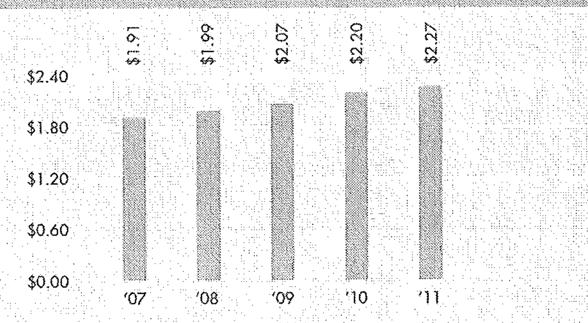
Our strategy is focused on maximizing the value of our regulated assets. It seeks to

- *maximize our regulated earnings capability* from our utility and pipeline operations,
- *complement our regulated operations* with energy services provided by our nonregulated business unit, and
- *enhance shareholder value* through prudent acquisitions and growing the rate base of our regulated companies.

In fiscal 2011, we achieved the following highlights.

- We enhanced the safety and reliability of our distribution system by replacing or adding more than 450 miles of natural gas pipelines.
- With our customers, we successfully resolved 19 rate filings, which are expected to increase annual operating income by more than $72 million.
- We strengthened our balance sheet going forward by impairing two natural gas gathering systems and a proposed natural gas storage project.
- We moved to become more geographically efficient by agreeing to sell our Missouri, Illinois and Iowa distribution assets for approximately $124 million.
- We benefited financially from unwinding two interest-rate agreements called Treasury locks, which we no longer needed, and from upgrades by two of the three major credit rating agencies.

Net Income per Diluted Share



Earnings per diluted share have increased steadily during the past five years due to our commitment to invest in system modernization, which has added to our utility rate base.

Financial Results

Earnings per diluted share increased by 7 cents over the $2.20 earned in fiscal 2010 to $2.27, marking our ninth consecutive year of higher annual earnings.

Consolidated net income rose from $205.8 million in fiscal 2010 to $207.6 million in fiscal 2011. Operating revenues for the fiscal year were $4.3 billion.

We paid cash dividends of $1.36 per share, and in November 2011 the board of directors raised the dividend by 2 cents a share for an annual indicated rate in fiscal 2012 of $1.38 per share. Our dividend payout ratio is 60 percent currently, as compared to 67 percent five years ago.

Our capital expenditures increased by $80.4 million, year over year, to $623.0 million. Approximately 70 percent of that spending was invested to modernize our gas distribution infrastructure and to enhance the safety and reliability of our pipeline system.

We continued to improve our rate designs and to seek rate settlements to avoid costly litigation.

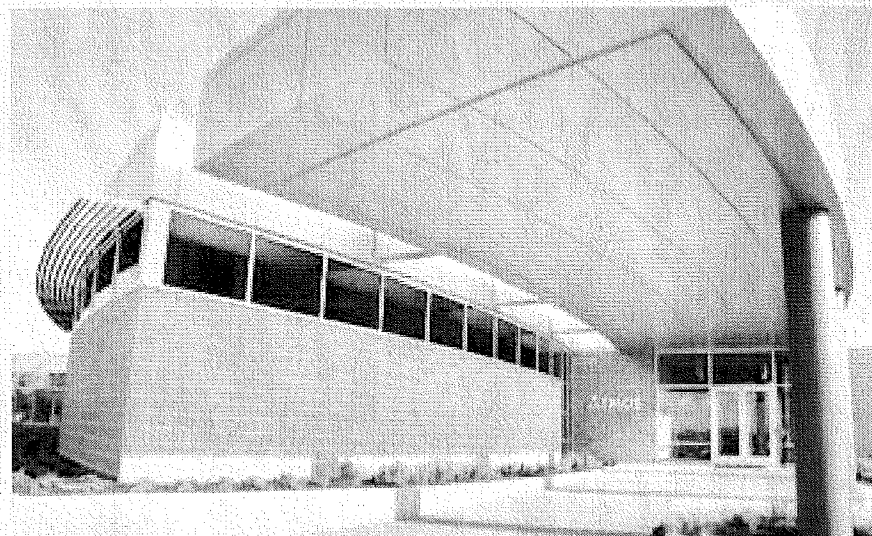
Regulatory authorities approved approximately $72 million in annual operating income increases from rate filings. In one of the settlements, the Railroad Commission of Texas decided a base rate case filed in 2010 by our Atmos Pipeline–Texas Division, resulting in an increase in annual operating income of about $20 million.

In our nonregulated operations, we recorded noncash charges of $30.3 million for operations that no longer offered reasonable prospects to meet our investment objectives. The cumulative adjustments lowered fiscal 2011 diluted earnings per share by about 21 cents.

Offsetting these impairment charges was a one-time $27.8 million pre-tax cash gain from unwinding two Treasury lock agreements with a cumulative notional value of $250 million. The Treasury locks, which are financial agreements for locking in interest rates for future debt issuances, were no longer needed after we cancelled an anticipated debt offering. In addition, we recorded a $5 million one-time benefit from an administrative settlement of various income tax positions. These gains improved earnings per diluted share by about 24 cents.

Shareholder value was further enhanced through our repurchase in fiscal 2011 and fiscal 2010 of more than 3.3 million shares of Atmos Energy common stock at an effective price of $29.99. The repurchased stock improved fiscal 2011 earnings per diluted share by about 8 cents a share. In addition, we plan to retire up to 5 million more shares over the next five years through our new share repurchase program.

During fiscal 2011, we strengthened our credit profile by reducing the company's number of credit facilities, interest costs and weighted average cost of debt. We received credit rating upgrades by Moody's Investors Service to Baa1 and by Fitch to A–, and Standard & Poor's reaffirmed its rating of BBB+.


In September, we opened Atmos Energy's new Amarillo Customer Contact Center to help ensure excellence in serving our customers.

Operational Developments

Our focus on modernizing our distribution system to ensure continued safety and reliability included many projects in all divisions to replace cast iron, steel mains and vintage distribution pipelines.

The largest of these projects is a steel service line replacement program in the Mid-Tex Division. The division made steady progress on its plan to make 100,000 line replacements by September 2012. Steel service lines installed from the 1940s through the 1960s are being converted to ½-inch-to-2-inch polyethylene pipe in more than 40 cities throughout the division.

Along with safety, we invested in major projects to provide excellent customer service. Development advanced from the design phase to the build phase on a new customer service software system that will improve the handling of our customer relationships, billing and communication. About 250 employees are involved in the project, with conversion to the new system expected in May 2013.

We also dedicated an $18.5 million customer contact center in Amarillo, Texas. The 52,500-square-foot facility replaced the company's original Amarillo call center, which opened in 1998. The new center features advanced telecommunications and information technologies to help handle a peak of approximately 1,900 calls an hour, ergonomic workstations for the center's 150 agents, a new dispatch arena and design features to increase energy performance and reduce waste. Atmos Energy is seeking LEED® silver certification* for the facility.

In May 2011, we entered into a definitive agreement to sell all of our Missouri, Illinois and Iowa gas distribution assets for a cash price of approximately $124 million. These operations, which serve some 84,000 meters in 189 communities, are being purchased by Liberty Energy (Midstates) Corp., an affiliate of Algonquin Power & Utilities Corp. The sale is expected to close in 2012 after regulatory approvals are granted. Selling these assets will allow us to better focus our distribution operations in our remaining nine states. Today about three-fourths of our utility operations are located in Texas, Louisiana and Mississippi.

In January and February 2011, hundreds of company employees dealt with frigid cold and record snowfall. Many spent days away from home keeping regulator stations operating and assisting customers. We appreciate our employees' dedication and concern for ensuring the safety and comfort of our customers.

As a testament to its operations, engineering and foresighted improvements, Atmos Pipeline–Texas successfully handled one of the largest peak-day demands in its history. Transmission volumes on February 2 exceeded 3.6 billion cubic feet (Bcf), which equaled the previous historical high in 1996, as temperatures remained below freezing for nearly 10 days across North Texas.

The pipeline, which is a primary transporter of natural gas to our Mid-Tex Division, met all its firm service obligations to human-needs gas customers during the cold wave. That same day, it also set a record of 2.5 Bcf in gas deliveries to our Mid-Tex Division and other North Texas local distribution companies.

During 2011, our nonregulated operations experienced declines in margins caused by weak natural gas market fundamentals, which provided fewer opportunities for favorable trading and asset optimization.

Although nonregulated gas sales volumes increased in fiscal 2011 by 9 percent to 384.8 Bcf over fiscal 2010 volumes, unit margins trended lower due to increased competition, lower basis spreads and continued depressed conditions of the economy. Atmos Energy Marketing remains a strong, regional leader in gas marketing and large-user services, and its results typically supplement earnings from our regulated distribution operations. AEM markets gas through physical delivery and maintains a conservative trading portfolio.

Employees in these operations worked diligently during the year to grow their customer base and sales volumes. We believe that Atmos Energy Marketing is stronger today than most of its competitors because it has successfully retained customers and won new business even under difficult conditions.

Board and Management Changes

We express our deep appreciation to Richard W. Cardin and Phillip E. Nichol who both retired from the board of directors in February 2011. Mr. Cardin, with 14 years of service as a director, also retired as chairman of the board's Audit Committee, and Mr. Nichol, with nearly 26 years of service, also retired as chairman of the Nominating and Corporate Governance Committee. These two directors contributed significantly to the company's growth and success, and we thank them for their dedication and service to our shareholders, customers and employees.

In November 2011, Marvin L. Sweetin was promoted to senior vice president, utility operations. Marvin joined Atmos Energy in 2000 after working for 13 years in the oil and gas industry. He has led our procurement, technical training and customer-service organizations as well as our enterprisewide Utility Operations Council. He has demonstrated a proven ability to control costs, improve operations and serve our customers well. In his new position, he serves on the company's Management Committee.

Favorable Future Outlook

The predictable and stable contributions from our regulated operations remain the cornerstone of our earnings framework. Although our nonregulated operations suffered because of tight market conditions this past year, Atmos Energy Marketing retained virtually all of its major gas marketing customers and added new ones. Its future prospects continue to complement the company's base earnings.

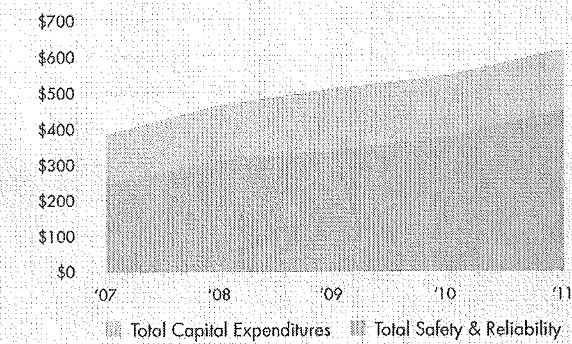
We intend to continue to invest—and our regulators have long approved of this goal—large amounts of capital needed to continually modernize our gas delivery system and safeguard our communities. We expect our capital expenditures in fiscal 2012 will range between $630 million and $650 million.

Our regulated utility rate base at the end of fiscal 2011 totaled about $4 billion. We expect the rate base will grow at a compound annual rate between 6.0 percent and 6.5 percent during the next five years. On average, this could add $50 million to $60 million annually in operating income.

Investing in our Texas intrastate transmission and storage operations promises not only to benefit our regulated distribution customers, but also to aid the state's natural gas producers in bringing more gas to market in Texas and elsewhere. Atmos Pipeline–Texas' approximately 6,000-mile system crosses the state from far West Texas to near the Louisiana border and from the Oklahoma border south to near Houston. It is strategically located to transport Barnett shale gas as well as more production from other shale gas basins now under development in the state.

The competitive price of natural gas and its many other benefits—it's clean, abundant, efficient and domestic—make our product the most likely fuel to meet the United States' energy needs for decades to come. As the economy improves, we believe natural gas will become the fuel of choice for new housing, factories, power plants and alternative transportation.

Investments for Safety and Reliability ($ in millions)



On average during the past five years, 68 percent of Atmos Energy's total capital expenditures have been dedicated to system modernization and expansion to provide safe and reliable distribution operations.

Growing through acquisitions will continue to be part of our future strategy. We have an enviable record of acquiring utility properties with little dilution and integrating them successfully. For example, during the past decade, most natural gas distribution merger or acquisition transactions cost their acquirers about 10 times EBITDA†, but ours averaged 7 to 8.5 times EBITDA.

We are a patient acquirer; we have made 10 major acquisitions since 1986. We also are one of the most efficient utility operators in the country, compared to our peers. We plan to pursue the acquisition of operations that we can run successfully and that make sense financially.

Our balance sheet is strong, with 48 percent equity at September 30, 2011. At fiscal year-end, we had $1.1 billion of total borrowing capacity, giving us ample liquidity for future needs and growth.

Taken altogether, we believe these strong, positive factors signify a favorable future outlook for Atmos Energy. For fiscal 2012, we expect our earnings will increase to between $2.30 and $2.40 per diluted share, excluding unrealized margins.

We appreciate the confidence shown by you, our investors, as well as by our 5,000 employees and our more than 3 million natural gas distribution customers. As Executive Chairman Robert W. Best has noted in previous annual reports, our purpose in business is to serve all our stakeholders—and to serve you well. That always stands as our No. 1 "blue chip" goal.

Kim R. Cocklin

Kim R. Cocklin
President and Chief Executive Officer
November 22, 2011

** LEED® stands for Leadership in Energy and Environmental Design and is a registered trademark of the nonprofit U.S. Green Building Council.*
† EBITDA, a common financial measure, stands for earnings before interest, taxes, depreciation and amortization.

Financial Highlights

Year Ended September 30 Dollars in thousands, except per share data	2011	2010	Change
Operating revenues	$ 4,347,634	$ 4,719,835	(7.9)%
Gross profit	$ 1,327,241	$ 1,337,505	(0.8)%
Natural gas distribution net income — continuing operations	$ 154,001	$ 118,383	30.1%
Natural gas distribution net income — discontinued operations	8,717	7,566	15.2%
Regulated transmission and storage net income	52,415	41,486	26.3%
Nonregulated net income (loss)	(7,532)	38,404	(119.6)%
Total	$ 207,601	$ 205,839	0.9%
Total assets	$ 7,282,871	$ 6,763,791	7.7%
Total capitalization*	$ 4,461,508	$ 3,987,899	11.9%
Net income per share from continuing operations — diluted	$ 2.17	$ 2.12	2.4%
Net income per share from discontinued operations — diluted	$ 0.10	$ 0.08	25.0%
Net income per share — diluted	$ 2.27	$ 2.20	3.2%
Cash dividends per share	$ 1.36	$ 1.34	1.5%
Book value per share at end of year	$ 24.98	$ 24.16	3.4%
Natural gas distribution throughput — continuing operations (MMcf)	409,369	438,535	(6.7)%
Natural gas distribution throughput — discontinued operations (MMcf)	14,651	15,640	(6.3)%
Consolidated natural gas distribution throughput (MMcf)	424,020	454,175	(6.6)%
Consolidated regulated transmission and storage transportation volumes (MMcf)	435,012	428,599	1.5%
Consolidated nonregulated delivered gas sales volumes (MMcf)	384,799	353,853	8.7%
Heating degree days[†]	2,733	2,780	(1.7)%
Degree days as a percentage of normal[†]	99%	102%	(2.9)%
Meters in service at end of year	3,213,191	3,186,040	0.9%
Return on average shareholders' equity	9.1%	9.1%	—
Shareholders' equity as a percentage of total capitalization (including short-term debt) at end of year	48.3%	48.7%	(0.8)%
Shareholders of record	18,680	19,738	(5.4)%
Weighted average shares outstanding — diluted (000s)	90,652	92,422	(1.9)%

* Total capitalization represents the sum of shareholders' equity and long-term debt, excluding current maturities.
[†] Heating degree days are adjusted for service areas with weather-normalized operations.

Summary Annual Report

The financial information presented in this report about Atmos Energy Corporation is condensed. Our complete financial statements, including notes as well as management's discussion and analysis of financial condition and results of operations, are presented in our *Annual Report on Form 10-K*. Atmos Energy's chief executive officer and its chief financial officer have executed all certifications with respect to the financial statements contained therein and have completed management's report on internal control over financial reporting, which are required under the Sarbanes-Oxley Act of 2002 and all related rules and regulations of the Securities and Exchange Commission. Investors may request, without charge, our *Annual Report on Form 10-K* for the fiscal year ended September 30, 2011, by calling Investor Relations at 972-855-3729 between 8 a.m. and 5 p.m. Central time. Our *Annual Report on Form 10-K* also is available on Atmos Energy's website at www.atmosenergy.com. Additional investor information is presented on pages 35 and 36 of this report.

Atmos Energy at a Glance

Year Ended September 30	2011	2010
Meters in service		
Residential	2,929,814	2,910,672
Commercial	270,774	262,778
Industrial	2,069	2,090
Public authority and other	10,934	10,500
Total meters	3,213,591	3,186,040
Heating degree days*		
Actual (weighted average)	2,733	2,780
Percent of normal	99%	102%
Natural gas distribution sales volumes — continuing operations (MMcf)		
Residential	161,012	185,143
Commercial	91,215	99,924
Industrial	18,757	18,714
Public authority and other	10,482	10,107
Total	281,466	313,888
Natural gas distribution transportation volumes — continuing operations (MMcf)	132,357	128,965
Total natural gas distribution throughput — continuing operations (MMcf)	413,823	442,853
Natural gas distribution sales volumes — discontinued operations (MMcf)	8,461	8,740
Natural gas distribution transportation volumes — discontinued operations (MMcf)	6,190	6,900
Intersegment activity (MMcf)	(4,454)	(4,318)
Consolidated natural gas distribution throughput (MMcf)	424,020	454,175
Consolidated regulated transmission and storage transportation volumes (MMcf)	435,012	428,599
Consolidated nonregulated delivered gas sales volumes (MMcf)	384,799	353,853
Operating revenues (000s)		
Natural gas distribution sales revenues		
Residential	$ 1,570,723	$ 1,784,051
Commercial	698,366	787,433
Industrial	106,569	110,280
Public authority and other	69,176	70,402
Total gas distribution sales revenues	2,444,834	2,752,166
Transportation revenues	59,547	58,511
Other gas revenues	26,599	31,091
Total natural gas distribution revenues	2,530,980	2,841,768
Regulated transmission and storage revenues	87,141	97,023
Nonregulated revenues	1,729,513	1,781,044
Total operating revenues (000s)	$ 4,347,634	$ 4,719,835
Other statistics		
Gross plant (000s)	$ 6,816,294	$ 6,542,318
Net plant (000s)	$ 5,147,918	$ 4,793,075
Miles of pipe	76,855	77,157
Employees	4,949	4,913

* Heating degree days are adjusted for service areas with weather-normalized operations.

Condensed Consolidated Balance Sheets

Year Ended September 30 Dollars in thousands, except share data	2011	2010
Assets		
Property, plant and equipment	$ 6,607,552	$ 6,384,396
Construction in progress	209,242	157,922
	6,816,794	6,542,318
Less accumulated depreciation and amortization	1,668,876	1,749,243
Net property, plant and equipment	5,147,918	4,793,075
Current assets		
Cash and cash equivalents	131,419	131,952
Accounts receivable, less allowance for doubtful accounts of $7,440 in 2011 and $12,701 in 2010	273,303	273,207
Gas stored underground	289,760	319,038
Other current assets	316,471	150,995
Total current assets	1,010,953	875,192
Goodwill and intangible assets	740,207	740,148
Deferred charges and other assets	383,793	355,376
	$ 7,282,871	$ 6,763,791
Capitalization and Liabilities		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2011 – 90,296,482 shares, 2010 – 90,164,103 shares	$ 451	$ 451
Additional paid-in capital	1,732,935	1,714,364
Accumulated other comprehensive loss	(48,460)	(23,372)
Retained earnings	570,495	486,905
Shareholders' equity	2,255,421	2,178,348
Long-term debt	2,206,117	1,809,551
Total capitalization	4,461,538	3,987,899
Current liabilities		
Accounts payable and accrued liabilities	291,205	266,208
Other current liabilities	367,563	413,640
Short-term debt	206,396	126,100
Current maturities of long-term debt	2,434	360,131
Total current liabilities	867,598	1,166,079
Deferred income taxes	960,093	829,128
Regulatory cost of removal obligation	428,947	350,521
Deferred credits and other liabilities	564,695	430,164
	$ 7,282,871	$ 6,763,791

Condensed Consolidated Statements of Income

Year Ended September 30 Dollars in thousands, except per share data	2011	2010	2009
Operating revenues			
Natural gas distribution segment	$ 2,531,868	$ 2,842,638	$ 2,884,796
Regulated transmission and storage segment	219,373	203,013	209,658
Nonregulated segment	2,024,893	2,146,658	2,283,988
Intersegment eliminations	(428,498)	(472,474)	(509,331)
	4,347,634	4,719,835	4,869,111
Purchased gas cost			
Natural gas distribution segment	1,487,499	1,820,627	1,887,192
Regulated transmission and storage segment	—	—	—
Nonregulated segment	1,959,893	2,032,567	2,169,880
Intersegment eliminations	(426,999)	(470,864)	(507,639)
	3,020,393	3,382,330	3,549,433
Gross profit	1,327,241	1,337,505	1,319,678
Operating expenses			
Operation and maintenance	449,290	460,513	485,704
Depreciation and amortization	227,099	211,589	211,984
Taxes, other than income	178,683	188,252	180,242
Asset impairments	30,270	—	5,382
Total operating expenses	885,342	860,354	883,312
Operating income	441,899	477,151	436,366
Miscellaneous income (expense), net	21,499	(156)	(3,067)
Interest charges	150,825	154,360	152,638
Income from continuing operations before income taxes	312,573	322,635	280,661
Income tax expense	113,689	124,362	97,362
Income from continuing operations	198,884	198,273	183,299
Income from discontinued operations, net of tax ($5,502, $4,425 and $2,929)	8,717	7,566	7,679
Net income	$ 207,601	$ 205,839	$ 190,978
Basic earnings per share			
Income per share from continuing operations	$ 2.18	$ 2.14	$ 1.99
Income per share from discontinued operations	0.10	0.08	0.09
Net income per share — basic	$ 2.28	$ 2.22	$ 2.08
Diluted earnings per share			
Income per share from continuing operations	$ 2.17	$ 2.12	$ 1.98
Income per share from discontinued operations	0.10	0.08	0.09
Net income per share — diluted	$ 2.27	$ 2.20	$ 2.07
Weighted average shares outstanding:			
Basic	90,201	91,852	91,117
Diluted	90,652	92,422	91,620

Condensed Consolidated Statements of Cash Flows

Year Ended September 30 Dollars in thousands	2011	2010	2009
Cash Flows from Operating Activities			
Net income	$ 207,601	$ 205,839	$ 190,978
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	30,270	—	5,382
Depreciation and amortization:			
Charged to depreciation and amortization	233,155	216,960	217,208
Charged to other accounts	228	173	94
Deferred income taxes	117,353	196,731	129,759
Stock-based compensation	11,586	12,655	14,494
Debt financing costs	9,438	11,908	10,364
Other	(961)	(1,245)	(1,177)
Changes in assets and liabilities	(25,826)	83,455	352,131
Net cash provided by operating activities	582,844	726,476	919,233
Cash Flows Used in Investing Activities			
Capital expenditures	(622,965)	(542,636)	(509,494)
Other, net	(4,421)	(66)	(7,707)
Net cash used in investing activities	(627,386)	(542,702)	(517,201)
Cash Flows from Financing Activities			
Net increase (decrease) in short-term debt	83,306	54,268	(283,981)
Net proceeds from issuance of long-term debt	394,406	—	445,623
Settlement of Treasury lock agreements	20,079	—	1,938
Unwinding of Treasury lock agreements	27,803	—	—
Repayment of long-term debt	(360,131)	(131)	(407,353)
Cash dividends paid	(124,011)	(124,287)	(121,460)
Repurchase of common stock	—	(100,450)	—
Repurchase of equity awards	(5,299)	(1,191)	—
Issuance of common stock	7,296	8,766	27,687
Net cash provided by (used in) financing activities	44,009	(163,025)	(337,546)
Net increase (decrease) in cash and cash equivalents	(533)	20,749	64,486
Cash and cash equivalents at beginning of year	131,952	111,203	46,717
Cash and cash equivalents at end of year	$ 131,419	$ 131,952	$ 111,203

Report of Independent Registered Public Accounting Firm on Condensed Financial Statements

The Board of Directors and Shareholders of Atmos Energy Corporation

We have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atmos Energy Corporation at September 30, 2011 and 2010, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2011 (not presented separately herein); and in our report dated November 22, 2011, we expressed an unqualified opinion on those consolidated financial statements.

In our opinion, the information set forth in the accompanying condensed consolidated financial statements is fairly stated in all material respects in relation to the consolidated financial statements from which it has been derived.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Atmos Energy Corporation's internal control over financial reporting as of September 30, 2011, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 22, 2011 (not presented separately herein) expressed an unqualified opinion thereon.

Ernst + Young LLP

Dallas, Texas
November 22, 2011

Consolidated Financial and Statistical Summary 2007–2011

Year Ended September 30	2011	2010	2009	2008	2007
Balance Sheet Data at September 30 (000s)					
Capital expenditures	$ 622,965	$ 542,636	$ 509,494	$ 472,273	$ 392,435
Net property, plant and equipment	5,147,918	4,793,075	4,439,103	4,136,859	3,836,836
Working capital	143,335	(290,887)	91,519	78,017	149,217
Total assets	7,282,871	6,763,791	6,367,083	6,386,699	5,895,197
Shareholders' equity	2,255,421	2,178,348	2,176,761	2,052,492	1,965,754
Long-term debt, excluding current maturities	2,206,117	1,809,551	2,169,400	2,119,792	2,126,315
Total capitalization	4,461,538	3,987,899	4,346,161	4,172,284	4,092,069
Income Statement Data					
Operating revenues (000s)	$ 4,347,634	$ 4,719,835	$ 4,869,111	$ 7,117,837	$ 5,803,177
Gross profit (000s)	1,327,241	1,337,505	1,319,678	1,293,922	1,221,078
Income from continuing operations (000s)	198,884	198,273	183,299	173,485	160,828
Income from discontinued operations, net of tax (000s)	8,717	7,566	7,679	6,846	7,664
Net income (000s)	207,601	205,839	190,978	180,331	168,492
Income per share from continuing operations—diluted	2.17	2.12	1.98	1.91	1.82
Income per share from discontinued operations—diluted	0.10	0.08	0.09	0.08	0.09
Net income per diluted share	2.27	2.20	2.07	1.99	1.91
Common Stock Data					
Shares outstanding (000s)					
End of year	90,296	90,164	92,552	90,815	89,327
Weighted average	90,652	92,422	91,620	89,941	87,486
Cash dividends per share	$ 1.36	$ 1.34	$ 1.32	$ 1.30	$ 1.28
Shareholders of record	18,680	19,738	20,790	21,756	22,829
Market price—High	$ 34.98	$ 30.06	$ 28.80	$ 29.46	$ 33.11
Low	$ 28.87	$ 26.41	$ 20.20	$ 25.09	$ 26.47
End of year	$ 32.45	$ 29.25	$ 28.18	$ 26.62	$ 28.32
Book value per share at end of year	$ 24.98	$ 24.16	$ 23.52	$ 22.60	$ 22.01
Price/Earnings ratio at end of year	14.30	13.30	13.61	13.38	14.83
Market/Book ratio at end of year	1.30	1.21	1.20	1.18	1.29
Annualized dividend yield at end of year	4.2%	4.6%	4.7%	4.9%	4.5%
Customers and Volumes (as metered)					
Consolidated distribution gas sales volumes (MMcf)	289,927	322,628	282,117	292,676	297,327
Consolidated distribution gas transportation volumes (MMcf)	134,093	131,547	126,768	136,678	130,542
Consolidated distribution throughput (MMcf)	424,020	454,175	408,885	429,354	427,869
Consolidated transmission and storage transportation volumes (MMcf)	435,012	428,599	528,689	595,542	505,493
Consolidated nonregulated delivered gas sales volumes (MMcf)	364,799	353,853	370,569	389,392	370,668
Meters in service at end of year	3,213,191	3,186,040	3,178,844	3,191,779	3,187,127
Heating degree days*	2,733	2,780	2,713	2,820	2,879
Degree days as a percentage of normal*	99%	102%	100%	100%	100%
Gas distribution average cost of gas per Mcf sold	$ 5.30	$ 5.77	$ 6.95	$ 9.05	$ 8.09
Gas distribution average transportation fee per Mcf	$ .46	$ .46	$ .46	$ .43	$ .44
Statistics					
Return on average shareholders' equity	9.1%	9.1%	8.9%	8.8%	8.8%
Number of employees	4,949	4,913	4,891	4,750	4,653
Net gas distribution plant per meter	$ 1,362	$ 1,243	$ 1,165	$ 1,091	$ 1,020
Gas distribution operation and maintenance expense per meter	$ 111	$ 114	$ 116	$ 122	$ 119
Meters per employee—gas distribution	676	676	678	700	713
Times interest earned before income taxes	3.13	3.09	2.82	3.06	2.75

* Heating degree days are adjusted for service areas with weather-normalized operations.

Atmos Energy Officers

Senior Management Team

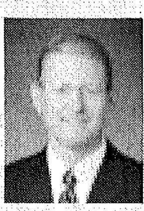
Robert W. Best
Executive Chairman
of the Board

Kim R. Cocklin
President and
Chief Executive Officer

Fred E. Meisenheimer
Senior Vice President and
Chief Financial Officer

Louis P. Gregory
Senior Vice President and
General Counsel

Michael E. Haefner
Senior Vice President,
Human Resources



Marvin L. Sweetin
Senior Vice President,
Utility Operations

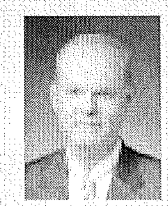
Regulated Divisions

J. Kevin Akers
President,
Kentucky/Mid-States Division

Richard A. Erskine
President,
Atmos Pipeline–Texas Division

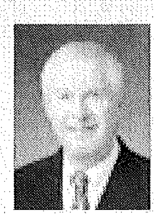
David E. Gates
President,
Mississippi Division

Gary W. Gregory
President,
West Texas Division



Tom S. Hawkins, Jr.
President,
Louisiana Division

John A. Paris
President,
Mid-Tex Division



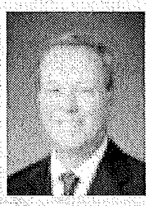
Gary L. Schlessman
President,
Colorado-Kansas Division

Atmos Energy Officers

Nonregulated Operations

Mark S. Bergeron
President,
Atmos Energy Holdings, Inc.

Shared Services



Verlon R. Aston, Jr.
Vice President,
Governmental and
Public Affairs

Christopher T. Forsythe
Vice President and Controller

Susan K. Giles
Vice President,
Investor Relations

Richard J. Gius
Vice President and
Chief Information Officer

Shared Services (continued)

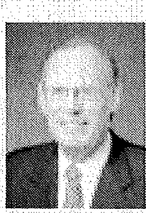
Conrad E. Gruber
Vice President,
Strategic Planning

Dwala J. Kuhn
Corporate Secretary

Kenneth M. Malter
Vice President,
Gas Supply and Services

Edward Pace McDonald IV
Vice President, Tax

Daniel M. Meziere
Vice President and Treasurer

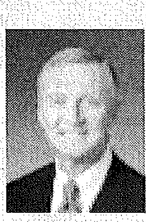


Robert W. Best
Executive Chairman
of the Board,
Atmos Energy Corporation
Dallas, Texas
Board member since 1997

Kim R. Cocklin
President and
Chief Executive Officer,
Atmos Energy Corporation
Dallas, Texas
Board member since 2009

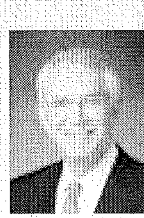
Richard W. Douglas
Executive Vice President,
Jones Lang LaSalle LLC
Dallas, Texas
Board member since 2007
Committees: Human
Resources, Work Session/
Annual Meeting

Ruben E. Esquivel
Vice President for
Community and Corporate
Relations, The University
of Texas Southwestern
Medical Center at Dallas
Dallas, Texas
Board member since 2008
Committees: Audit,
Human Resources

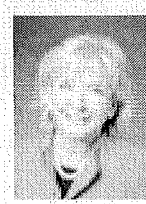


Richard K. Gordon
General Partner, Juniper
Energy LP, Juniper Capital LP
and Juniper Advisory LP
Houston, Texas
Board member since 2001
Committees: Human
Resources (Chairman),
Executive, Nominating and
Corporate Governance

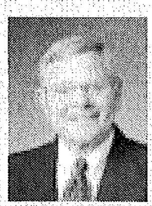
Robert C. Grable
Partner, Kelly Hart &
Hallman LLP
Fort Worth, Texas
Board member since 2009
Committees: Audit,
Human Resources



Dr. Thomas C. Meredith
Retired, formerly
Commissioner of Mississippi
Institutions of Higher Learning
Jackson, Mississippi
Board member since 1995
Committees: Work Session/
Annual Meeting (Chairman),
Audit, Executive, Nominating
and Corporate Governance

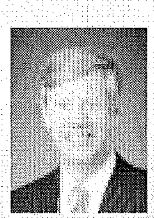


Nancy K. Quinn
Principal, Hanover
Capital, LLC
East Hampton, New York
Board member since 2004
Committees: Audit (Chair),
Executive, Nominating and
Corporate Governance

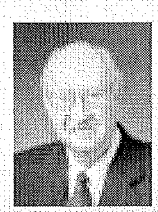


Stephen R. Springer
Retired Senior Vice President
and General Manager,
Midstream Division,
The Williams Companies, Inc.
Fort Myers Beach, Florida
Board member since 2005
Committee: Work Session/
Annual Meeting

Charles K. Vaughan
Retired Chairman
of the Board,
Atmos Energy Corporation
Dallas, Texas
Board member since 1983
Lead Director since 2003
Committee: Executive
(Chairman)



Richard Ware II
President, Amarillo
National Bank
Amarillo, Texas
Board member since 1994
Committees: Nominating and
Corporate Governance
(Chairman), Audit,
Executive, Work Session/
Annual Meeting



Lee E. Schlessman
Honorary Director
President, Dolo
Investment Company
Denver, Colorado
Retired from Board in 1998

Common Stock Listing
New York Stock Exchange. Trading symbol: ATO

Stock Transfer Agent and Registrar
American Stock Transfer & Trust Company, LLC
Operations Center
6201 15th Avenue
Brooklyn, New York 11219
800-543-3038

To inquire about your Atmos Energy common stock, please call AST at the telephone number above. You may use the agent's interactive voice response system 24 hours a day to learn about transferring stock or to check your recent account activity, all without the assistance of a customer service representative. Please have available your Atmos Energy shareholder account number and your Social Security or federal taxpayer ID number.

To speak to an AST customer service representative, please call the same number between 8 a.m. and 7 p.m. Eastern time, Monday through Thursday, or 8 a.m. to 5 p.m. Eastern time on Friday.

You also may send an email message on our agent's website at www.amstock.com. Please refer to Atmos Energy in your email message and include your Atmos Energy shareholder account number.

Independent Registered Public Accounting Firm
Ernst & Young LLP
One Victory Park
Suite 2000
2323 Victory Avenue
Dallas, Texas 75219
214-969-8000

Form 10-K
Atmos Energy Corporation's *Annual Report on Form 10-K* is available at no charge from Investor Relations, Atmos Energy Corporation, P.O. Box 650205, Dallas, Texas 75265-0205 or by calling 972-855-3729 between 8 a.m. and 5 p.m. Central time. Atmos Energy's Form 10-K also may be viewed on Atmos Energy's website at www.atmosenergy.com.

Annual Meeting of Shareholders
The 2012 Annual Meeting of Shareholders will be held in the Lincoln Ballroom at the Hilton Hotel Lincoln Centre, 5410 LBJ Freeway, Dallas, Texas 75240 on Wednesday, February 8, 2012, at 9:30 a.m. Central time.

Direct Stock Purchase Plan
Atmos Energy Corporation has a Direct Stock Purchase Plan that is available to all investors. For an Enrollment Application Form and a Plan Prospectus, please call AST at 800-543-3038. The Prospectus is also available at www.atmosenergy.com. You may also obtain information by writing to Investor Relations, Atmos Energy Corporation, P.O. Box 650205, Dallas, Texas 75265-0205.

This is not an offer to sell, or a solicitation to buy, any securities of Atmos Energy Corporation. Shares of Atmos Energy common stock purchased through the Direct Stock Purchase Plan will be offered only by Prospectus.

Atmos Energy on the Internet
Information about Atmos Energy is available on the Internet at www.atmosenergy.com. Our website includes news releases, current and historical financial reports, other investor data, corporate governance documents, management biographies, customer information and facts about Atmos Energy's operations.

Atmos Energy Corporation Contacts
To contact Atmos Energy's Investor Relations, call 972-855-3729 between 8 a.m. and 5 p.m. Central time or send an email message to InvestorRelations@atmosenergy.com.

Securities analysts and investment managers, please contact:

Susan K. Giles
Vice President, Investor Relations
972-855-3729 (voice) 972-855-3040 (fax)
InvestorRelations@atmosenergy.com

Forward-looking Statements

The matters discussed or incorporated by reference in this *Summary Annual Report* may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this report are forward-looking statements made in good faith by the Company and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this report or any other of the Company's documents or oral presentations, the words "anticipate," "believe," "estimate," "expect," "forecast," "goal," "intend," "objective," "plan," "projection," "seek," "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those discussed in this report. These risks and uncertainties are discussed in the Company's *Annual Report on Form 10-K* for the fiscal year ended September 30, 2011. Although the Company believes these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, the Company undertakes no obligation to update or revise any of its forward-looking statements, whether as a result of new information, future events or otherwise.

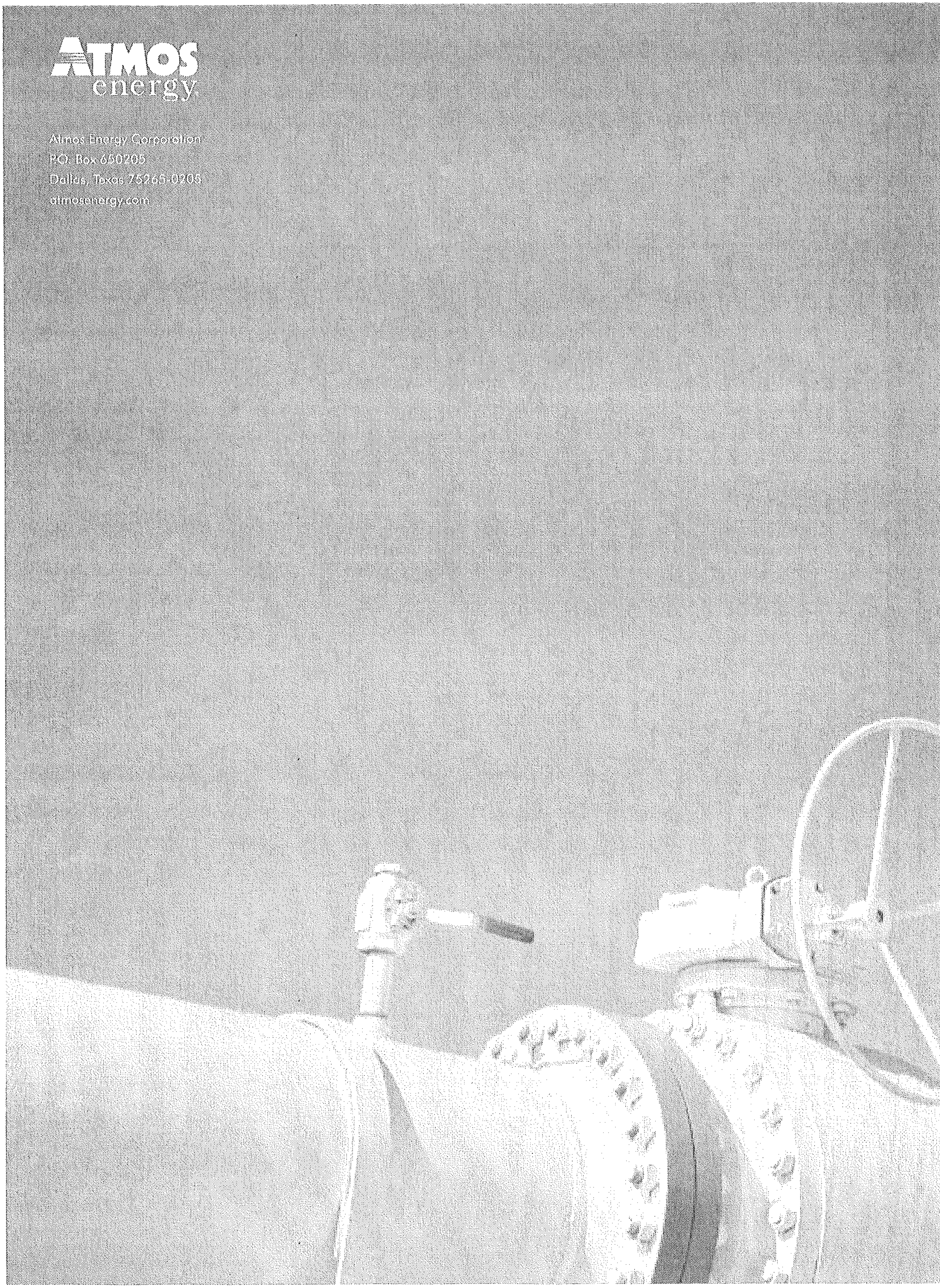
Other Information

You can view this *Summary Annual Report*, our *Annual Report on Form 10-K* and other financial documents for fiscal 2011 and previous years at www.atmosenergy.com.

If you are a shareholder who would like to receive our *Summary Annual Report* and other company documents electronically in the future, please sign up for electronic distribution. It's convenient and easy, and it saves the costs to produce and distribute these materials.

To receive these documents over the Internet next year, please visit www.amstock.com and access your account to give your consent. Please remember that accessing our *Summary Annual Report* and other company documents over the Internet may result in charges to you from your Internet service provider or telephone company.

Atmos Energy vehicles display the national Call 811 logo to remind the public to always call 811 before digging to have natural gas pipelines and other buried utility lines marked at no charge.



Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205
atmosenergy.com

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2011

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia	**75-1743247**
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 **5430 LBJ Freeway, Dallas, Texas**	**75240**
(Address of principal executive offices)	*(Zip code)*

Registrant's telephone number, including area code:
(972) 934-9227

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, No Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the common voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2011, was $3,008,806,271.

As of November 14, 2011, the registrant had 90,364,061 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 8, 2012, are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
APS	Atmos Pipeline and Storage, LLC
ATO	Trading symbol for Atmos Energy Corporation common stock on the New York Stock Exchange
Bcf	Billion cubic feet
COSO	Committee of Sponsoring Organizations of the Treadway Commission
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Ltd.
GRIP	Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
ISRS	Infrastructure System Replacement Surcharge
KPSC	Kentucky Public Service Commission
LTIP	1998 Long-Term Incentive Plan
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
MMcf	Million cubic feet
Moody's	Moody's Investor Services, Inc.
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
PAP	Pension Account Plan
RRC	Railroad Commission of Texas
RRM	Rate Review Mechanism
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
Settled Cities	Represents 439 of the 440 incorporated cities, or approximately 80 percent of the Mid-Tex Division's customers, with whom a settlement agreement was reached during the fiscal 2008 second quarter.
SRF	Stable Rate Filing
WNA	Weather Normalization Adjustment

PART I

The terms "we," "our," "us", "Atmos Energy" and the "Company" refer to Atmos Energy Corporation and its subsidiaries, unless the context suggests otherwise.

ITEM 1. *Business.*

Overview and Strategy

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other nonregulated natural gas businesses. Since our incorporation in Texas in 1983, we have grown primarily through a series of acquisitions, the most recent of which was the acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas Company. We are also incorporated in the state of Virginia.

Today, we distribute natural gas through regulated sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers in 12 states located primarily in the South, which makes us one of the country's largest natural-gas-only distributors based on number of customers. In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. After the closing of this transaction, we will operate in nine states. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers principally in the Midwest and Southeast and natural gas transportation along with storage services to certain of our natural gas distribution divisions and third parties.

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while safely operating our regulated and nonregulated businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

We have continued to grow our earnings after giving effect to our acquisitions and have experienced more than 25 consecutive years of increasing dividends. Historically, we achieved this record of growth through acquisitions while efficiently managing our operating and maintenance expenses and leveraging our technology to achieve more efficient operations. In recent years, we have also achieved growth by implementing rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns. In addition, we have developed various commercial opportunities within our regulated transmission and storage operations.

Our core values include focusing on our employees and customers while conducting our business with honesty and integrity. We continue to strengthen our culture through ongoing communications with our employees and enhanced employee training.

Operating Segments

We operate the Company through the following three segments:

- The *natural gas distribution segment*, which includes our regulated natural gas distribution and related sales operations,
- The *regulated transmission and storage segment*, which includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division and

- The *nonregulated segment*, which includes our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services.

These operating segments are described in greater detail below.

Natural Gas Distribution Segment Overview

Our natural gas distribution segment consists of the following six regulated divisions, presented in order of total rate base, covering service areas in 12 states:

- Atmos Energy Mid-Tex Division,
- Atmos Energy Kentucky/Mid-States Division,
- Atmos Energy Louisiana Division,
- Atmos Energy West Texas Division,
- Atmos Energy Mississippi Division and
- Atmos Energy Colorado-Kansas Division

Our natural gas distribution business is a seasonal business. Gas sales to residential and commercial customers are greater during the winter months than during the remainder of the year. The volumes of gas sales during the winter months will vary with the temperatures during these months.

Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. See Note 6 in the consolidated financial statements for a complete description of the anticipated sale of our Illinois, Iowa and Missouri service areas. In addition, we transport natural gas for others through our distribution system.

Rates established by regulatory authorities often include cost adjustment mechanisms for costs that (i) are subject to significant price fluctuations compared to our other costs, (ii) represent a large component of our cost of service and (iii) are generally outside our control.

Purchased gas cost adjustment mechanisms represent a common form of cost adjustment mechanism. Purchased gas cost adjustment mechanisms provide natural gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case because they provide a dollar-for-dollar offset to increases or decreases in natural gas distribution gas costs. Therefore, although substantially all of our natural gas distribution operating revenues fluctuate with the cost of gas that we purchase, natural gas distribution gross profit (which is defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas.

Additionally, some jurisdictions have introduced performance-based ratemaking adjustments to provide incentives to natural gas utilities to minimize purchased gas costs through improved storage management and use of financial instruments to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility and its customers.

Finally, regulatory authorities have approved weather normalization adjustments (WNA) for approximately 94 percent of residential and commercial margins in our service areas as a part of our rates. WNA minimizes the effect of weather that is above or below normal by allowing us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal.

As of September 30, 2011 we had WNA for our residential and commercial meters in the following service areas for the following periods:

Georgia, Kansas, West Texas	October — May
Kentucky, Mississippi, Tennessee, Mid-Tex	November — April
Louisiana	December — March
Virginia	January — December

Our supply of natural gas is provided by a variety of suppliers, including independent producers, marketers and pipeline companies and withdrawals of gas from proprietary and contracted storage assets. Additionally, the natural gas supply for our Mid-Tex Division includes peaking and spot purchase agreements.

Supply arrangements consist of both base load and swing supply (peaking) quantities and are contracted from our suppliers on a firm basis with various terms at market prices. Base load quantities are those that flow at a constant level throughout the month and swing supply quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions.

Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically requesting proposals from suppliers that have demonstrated that they can provide reliable service. We select these suppliers based on their ability to deliver gas supply to our designated firm pipeline receipt points at the lowest cost. Major suppliers during fiscal 2011 were Anadarko Energy Services, BP Energy Company, ConocoPhillips, Devon Gas Services, L.P., Enbridge Marketing (US) L.P., Iberdrola Renewables, Inc., National Fuel Marketing Company, LLC, ONEOK Energy Services Company L.P., Tenaska Marketing and Atmos Energy Marketing, LLC, our natural gas marketing subsidiary.

The combination of base load, peaking and spot purchase agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments. We estimate our peak-day availability of natural gas supply to be approximately 4.4 Bcf. The peak-day demand for our natural gas distribution operations in fiscal 2011 was on February 2, 2011, when sales to customers reached approximately 4.4 Bcf.

Currently, our natural gas distribution divisions, except for our Mid-Tex Division, utilize 45 pipeline transportation companies, both interstate and intrastate, to transport our natural gas. The pipeline transportation agreements are firm and many of them have "pipeline no-notice" storage service, which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered primarily by our Atmos Pipeline — Texas Division.

To maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to curtail deliveries to certain customers under the terms of interruptible contracts or applicable state regulations or statutes. Our customers' demand on our system is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a firm basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of our customers. We anticipate no problems with obtaining additional gas supply as needed for our customers.

Below, we briefly describe our six natural gas distribution divisions. We operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2011, we held 1,116 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire. Additional information concerning our natural gas distribution divisions is presented under the caption "Operating Statistics".

Atmos Energy Mid-Tex Division. Our Mid-Tex Division serves approximately 550 incorporated and unincorporated communities in the north-central, eastern and western parts of Texas, including the Dallas/Fort Worth Metroplex. The governing body of each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. The Railroad Commission of Texas (RRC) has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality.

Prior to fiscal 2008, this division operated under one system-wide rate structure. However, in fiscal 2008, we reached a settlement with cities representing approximately 80 percent of this division's customers (Settled Cities) that has allowed us, beginning in fiscal 2008, to update rates for customers in these cities through an annual rate review mechanism (RRM). Rates for the remaining 20 percent of this division's customers, primarily the City of Dallas, continue to be updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. In June 2011, we reached an agreement with the City of Dallas to enter into the Dallas Annual Rate Review (DARR). This rate review provides for an annual rate review without the necessity of filing a general rate case. The first filing made under this mechanism will be in January 2012.

Atmos Energy Kentucky/Mid-States Division. Our Kentucky/Mid-States Division operates in more than 420 communities across Georgia, Illinois, Iowa, Kentucky, Missouri, Tennessee and Virginia. The service areas in these states are primarily rural; however, this division serves Franklin, Tennessee and other suburban areas of Nashville. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 189 communities, some of which of the Missouri communities are located in our Atmos Energy Colorado-Kansas Division.

Atmos Energy Louisiana Division. In Louisiana, we serve nearly 300 communities, including the suburban areas of New Orleans, the metropolitan area of Monroe and western Louisiana. Direct sales of natural gas to industrial customers in Louisiana, who use gas for fuel or in manufacturing processes, and sales of natural gas for vehicle fuel are exempt from regulation and are recognized in our nonregulated segment. Our rates in this division are updated annually through a rate stabilization clause filing without filing a formal rate case.

Atmos Energy West Texas Division. Our West Texas Division serves approximately 80 communities in West Texas, including the Amarillo, Lubbock and Midland areas. Like our Mid-Tex Division, each municipality we serve has original jurisdiction over all gas distribution rates, operations and services within its city limits, with the RRC having exclusive appellate jurisdiction over the municipalities and exclusive original jurisdiction over rates and services provided to customers not located within the limits of a municipality. Prior to fiscal 2008, rates were updated in this division through formal rate proceedings. However, the West Texas Division entered into agreements with its West Texas service areas during fiscal 2008 and its Amarillo and Lubbock service areas during fiscal 2009 to update rates for customers in these service areas through an RRM.

Atmos Energy Mississippi Division. In Mississippi, we serve about 110 communities throughout the northern half of the state, including the Jackson metropolitan area. Our rates in the Mississippi Division are updated annually through a stable rate filing without filing a formal rate case.

Atmos Energy Colorado-Kansas Division. Our Colorado-Kansas Division serves approximately 170 communities throughout Colorado and Kansas and parts of Missouri, including the cities of Olathe, Kansas, a suburb of Kansas City and Greeley, Colorado, located near Denver. We update our rates in this division through periodic formal rate filings made with each state's public service commission.

The following table provides a jurisdictional rate summary for our regulated operations. This information is for regulatory purposes only and may not be representative of our actual financial position.

Division	Jurisdiction	Effective Date of Last Rate/GRIP Action	Rate Base (thousands)[1]	Authorized Rate of Return[1]	Authorized Return on Equity[1]
Atmos Pipeline — Texas	Texas	05/01/2011	$807,733	9.36%	11.80%
Atmos Pipeline — Texas — GRIP	Texas	08/01/2011	816,976	9.36%	11.80%
Colorado-Kansas	Colorado	01/04/2010	86,189	8.57%	10.25%
	Kansas	08/01/2010	144,583	(2)	(2)
Kentucky/Mid-States	Georgia	03/31/2010	96,330[3]	8.61%	10.70%
	Illinois	11/01/2000	24,564	9.18%	11.56%
	Iowa	03/01/2001	5,000	(2)	11.00%
	Kentucky	06/01/2010	208,702[4]	(2)	(2)
	Missouri	09/01/2010	66,459	(2)	(2)
	Tennessee	04/01/2009	190,100	8.24%	10.30%
	Virginia	11/23/2009	36,861	8.48%	9.50% - 10.50%
Louisiana	Trans LA	04/01/2011	93,260	8.37%	10.00% - 10.80%
	LGS	07/01/2011	273,775	8.56%	10.40%
Mid-Tex — Settled Cities	Texas	09/01/2011	1,389,187[5]	8.29%	9.70%
Mid-Tex — Dallas	Texas	06/22/2011	1,268,601[5]	8.45%	10.10%
Mid-Tex — Environs GRIP	Texas	06/27/2011	1,268,601[5]	8.60%	10.40%
Mississippi	Mississippi	04/05/2011	239,197	(2)	9.86%
West Texas	Amarillo	08/01/2011	(2)	(2)	9.60%
	Lubbock	09/09/2011	60,892	8.19%	9.60%
	West Texas	08/01/2011	146,039	8.19%	9.60%

Division	Jurisdiction	Authorized Debt/ Equity Ratio	Bad Debt Rider[6]	WNA	Performance-Based Rate Program[7]	Customer Meters
Atmos Pipeline — Texas	Texas	50/50	No	N/A	N/A	N/A
Colorado-Kansas	Colorado	50/50	Yes[8]	No	No	110,709
	Kansas	(2)	Yes	Yes	No	128,679
Kentucky/Mid-States	Georgia	52/48	No	Yes	Yes	63,897
	Illinois	67/33	No	No	No	22,778
	Iowa	57/43	No	No	No	4,334
	Kentucky	(2)	Yes	Yes	Yes	176,246
	Missouri	49/51	No	No	No	56,643
	Tennessee	52/48	Yes	Yes	Yes	133,634
	Virginia	51/49	Yes	Yes	No	23,310
Louisiana................	Trans LA	52/48	No	Yes	No	75,813
	LGS	52/48	No	Yes	No	277,838
Mid-Tex — Settled Cities....	Texas	50/50	Yes	Yes	No	1,259,042
Mid-Tex — Dallas & Environs	Texas	51/49	Yes	Yes	No	314,760
Mississippi	Mississippi	50/50	No	Yes	No	266,074
West Texas	Amarillo	52/48	Yes	Yes	No	70,431
	Lubbock	52/48	Yes	Yes	No	73,748
	West Texas	52/48	Yes	Yes	No	155,255

(1) The rate base, authorized rate of return and authorized return on equity presented in this table are those from the most recent rate case or GRIP filing for each jurisdiction. These rate bases, rates of return and returns on equity are not necessarily indicative of current or future rate bases, rates of return or returns on equity.

(2) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.

(3) Georgia rate base consists of $60.2 million included in the March 2010 rate case and $36.1 million included in the October 2011 Pipeline Replacement Program (PRP) surcharge. A total of $36.1 million of the Georgia rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.56 percent and an authorized return on equity of 10.70 percent.

(4) Kentucky rate base consists of $184.7 million included in the June 2010 rate case and $24.0 million included in the October 2011 PRP surcharge. A total of $24.0 million of the Kentucky rate base amount was awarded in the latest PRP annual filing with an effective date of October 1, 2011, an authorized rate of return of 8.74 percent and an authorized return on equity of 10.50 percent.

(5) The Mid-Tex Rate Base amounts for the Settled Cities and Dallas & Environs areas represent "system-wide", or 100 percent, of the Mid-Tex Division's rate base.

(6) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.

(7) The performance-based rate program provides incentives to natural gas utility companies to minimize purchased gas costs by allowing the utility company and its customers to share the purchased gas costs savings.

(8) The recovery of the gas portion of uncollectible accounts gas cost adjustment has been approved for a two-year pilot program.

Natural Gas Distribution Sales and Statistical Data - Continuing Operations

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
METERS IN SERVICE, end of year					
Residential	2,855,998	2,836,483	2,826,814	2,834,884	2,815,974
Commercial	261,220	253,339	256,384	259,154	262,260
Industrial	2,008	2,029	2,136	2,183	2,281
Public authority and other	10,212	10,178	9,211	9,197	19,143
Total meters	3,129,438	3,102,029	3,094,545	3,105,418	3,099,658
SALES VOLUMES — MMcf[2]					
Gas Sales Volumes					
Residential	161,012	185,143	154,475	157,816	161,493
Commercial	91,215	99,924	88,445	90,992	92,601
Industrial	18,757	18,714	18,242	21,352	22,479
Public authority and other	10,482	10,107	12,393	13,739	12,265
Total gas sales volumes	281,466	313,888	273,555	283,899	288,838
Transportation volumes	132,357	128,965	123,972	133,997	127,066
Total throughput	413,823	442,853	397,527	417,896	415,904
OPERATING REVENUES (000's)[2]					
Gas Sales Revenues					
Residential	$1,570,723	$1,784,051	$1,768,082	$2,068,040	$1,924,523
Commercial	698,366	787,433	807,109	1,044,768	941,827
Industrial	106,569	110,280	132,487	208,681	190,812
Public authority and other	69,176	70,402	88,972	137,585	114,087
Total gas sales revenues	2,444,834	2,752,166	2,796,650	3,459,074	3,171,249
Transportation revenues	60,430	59,381	56,961	57,405	56,814
Other gas revenues	26,599	31,091	31,185	35,183	35,448
Total operating revenues	$2,531,863	$2,842,638	$2,884,796	$3,551,662	$3,263,511

Natural Gas Distribution Sales and Statistical Data - Discontinued Operations

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
Meters in service, end of period	83,753	84,011	84,299	86,361	87,469
Sales volumes — MMcf					
Total gas sales volumes	8,461	8,740	8,562	8,777	8,489
Transportation volumes	6,190	6,900	6,719	7,086	8,043
Total throughput	14,651	15,640	15,281	15,863	16,532
Operating revenues (000's)	$80,028	$69,855	$99,969	$103,468	$95,254

See footnotes following these tables.

Natural Gas Distribution Sales and Statistical Data - Other Consolidated Statistics

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
Inventory storage balance — Bcf	55.0	54.3	57.0	58.3	58.0
Heating degree days[1]					
Actual (weighted average)	2,733	2,780	2,713	2,820	2,879
Percent of normal	99%	102%	100%	100%	100%
Average transportation revenue per Mcf	$ 0.46	$ 0.46	$ 0.46	$ 0.43	$ 0.44
Average cost of gas per Mcf sold	$ 5.30	$ 5.77	$ 6.95	$ 9.05	$ 8.09
Employees	4,753	4,714	4,691	4,558	4,472

Natural Gas Distribution Sales and Statistical Data by Division

	Fiscal Year Ended September 30, 2011							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado-Kansas	Other[3]	Total
METERS IN SERVICE FROM CONTINUING OPERATIONS								
Residential	1,449,673	349,993	331,272	271,346	237,059	216,655	—	2,855,998
Commercial	123,993	43,875	22,379	24,773	25,617	20,583	—	261,220
Industrial	136	798	—	482	501	91	—	2,008
Public authority and other	—	2,423	—	2,833	2,897	2,059	—	10,212
Total meters	1,573,802	397,089	353,651	299,434	266,074	239,388	—	3,129,438
SALES VOLUMES FROM CONTINUING OPERATIONS — MMcf[2]								
Gas Sales Volumes								
Residential	77,075	22,273	13,939	16,280	14,077	17,368	—	161,012
Commercial	50,056	13,407	7,448	6,932	6,630	6,742	—	91,215
Industrial	3,105	5,626	—	4,108	5,823	95	—	18,757
Public authority and other	—	1,395	—	3,294	3,418	2,375	—	10,482
Total	130,236	42,701	21,387	30,614	29,948	26,580	—	281,466
Transportation volumes	46,594	38,801	5,893	24,162	5,237	11,670	—	132,357
Total throughput	176,830	81,502	27,280	54,776	35,185	38,250	—	413,823
OPERATING MARGIN FROM CONTINUING OPERATIONS (000's)[2]	$ 490,484	$152,293	$125,894	$ 99,353	$ 93,042	$ 83,298	$ —	$1,044,364
OPERATING EXPENSES FROM CONTINUING OPERATIONS (000's)[2]								
Operation and maintenance	$ 147,967	$ 58,315	$ 42,219	$ 35,908	$ 39,895	$ 31,684	$ (7,905)	$ 348,083
Depreciation and amortization	$ 95,798	$ 29,644	$ 24,460	$ 16,735	$ 13,188	$ 17,084	$ —	$ 196,909
Taxes, other than income	$ 102,515	$ 10,828	$ 8,773	$ 17,024	$ 13,621	$ 8,610	$ —	$ 161,371
OPERATING INCOME FROM CONTINUING OPERATIONS (000's)[2]	$ 144,204	$ 53,506	$ 50,442	$ 29,686	$ 26,338	$ 25,920	$ 7,905	$ 338,001
CONSOLIDATED CAPITAL EXPENDITURES (000's)	$ 220,032	$ 65,766	$ 41,489	$ 40,387	$ 37,115	$ 31,399	$ 60,711	$ 496,899
PROPERTY, PLANT AND EQUIPMENT, EXCLUDING ASSETS HELD FOR SALE (000's)	$1,965,351	$663,837	$431,773	$393,545	$308,891	$311,013	$173,788	$4,248,198
OTHER CONSOLIDATED STATISTICS								
Heating Degree Days[1]								
Actual	2,100	3,920	1,431	3,541	2,707	5,692	—	2,733
Percent of normal	100%	99%	94%	99%	101%	101%	—	99%
Miles of pipe	29,296	12,215	8,333	7,712	6,563	6,750	—	70,869
Employees	1,668	568	438	351	363	287	1,078	4,753

See footnotes following these tables.

	Fiscal Year Ended September 30, 2010							
	Mid-Tex	Kentucky/ Mid-States	Louisiana	West Texas	Mississippi	Colorado-Kansas	Other[3]	Total
METERS IN SERVICE FROM CONTINUING OPERATIONS								
Residential	1,429,287	350,238	331,784	271,418	237,304	216,452	—	2,836,483
Commercial	116,240	43,554	22,420	24,919	25,520	20,686	—	253,339
Industrial	145	801	—	484	513	86	—	2,029
Public authority and other	—	2,411	—	2,809	2,896	2,062	—	10,178
Total meters	1,545,672	397,004	354,204	299,630	266,233	239,286	—	3,102,029
SALES VOLUMES FROM CONTINUING OPERATIONS — MMcf[2]								
Gas Sales Volumes								
Residential	92,489	22,897	15,810	19,772	15,775	18,400	—	185,143
Commercial	55,916	13,948	7,821	7,892	7,209	7,138	—	99,924
Industrial	3,227	5,615	—	4,317	5,424	131	—	18,714
Public authority and other	—	1,422	—	3,482	3,103	2,100	—	10,107
Total	151,632	43,882	23,631	35,463	31,511	27,769	—	313,888
Transportation volumes	45,822	36,882	5,626	22,429	5,551	12,655	—	128,965
Total throughput	197,454	80,764	29,257	57,892	37,062	40,424	—	442,853
OPERATING MARGIN FROM CONTINUING OPERATIONS (000's)[2]	$ 475,852	$143,347	$123,344	$105,476	$ 94,203	$ 79,789	$ —	$1,022,011
OPERATING EXPENSES FROM CONTINUING OPERATIONS (000's)[2]								
Operation and maintenance	$ 145,166	$ 56,481	$ 43,604	$ 36,696	$ 41,542	$ 30,892	$ 976	$ 355,357
Depreciation and amortization	$ 89,411	$ 28,066	$ 22,986	$ 15,881	$ 12,621	$ 16,182	$ —	$ 185,147
Taxes, other than income	$ 106,620	$ 12,562	$ 10,995	$ 19,390	$ 13,599	$ 8,172	$ —	$ 171,338
OPERATING INCOME FROM CONTINUING OPERATIONS (000's)[2]	$ 134,655	$ 46,238	$ 45,759	$ 33,509	$ 26,441	$ 24,543	$ (976)	$ 310,169
CONSOLIDATED CAPITAL EXPENDITURES (000's)	$ 196,109	$ 62,808	$ 47,193	$ 39,387	$ 28,538	$ 29,792	$ 33,988	$ 437,815
CONSOLIDATED PROPERTY, PLANT AND EQUIPMENT (000's)	$1,761,087	$750,225	$413,189	$319,053	$284,195	$300,380	$130,983	$3,959,112
OTHER CONSOLIDATED STATISTICS								
Heating Degree Days[1]								
Actual	2,100	3,924	1,532	3,537	2,734	5,909	—	2,780
Percent of normal	103%	100%	96%	99%	102%	106%	—	102%
Miles of pipe	29,156	12,196	8,381	7,666	6,546	7,175	—	71,120
Employees	1,650	587	439	344	371	284	1,039	4,714

Natural Gas Distribution Sales and Statistical Data by Division - Discontinued Operations

	Fiscal Year Ended September 30, 2011			Fiscal Year Ended September 30, 2010		
	Kentucky/ Mid-States	Colorado-Kansas	Total	Kentucky/ Mid-States	Colorado-Kansas	Total
Meters in service, end of period	83,325	428	83,753	83,577	434	84,011
Sales volumes — MMcf						
Total gas sales volumes	7,963	498	8,461	8,251	489	8,740
Transportation volumes	6,190	—	6,190	6,900	—	6,900
Total throughput	14,153	498	14,651	15,151	489	15,640
Operating income (000's)	$13,395	$1,020	$14,415	$11,628	$657	$12,285

Notes to preceding tables:

(1) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days.

Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

(2) Sales volumes, revenues, operating margins, operating expense and operating income reflect segment operations, including intercompany sales and transportation amounts.

(3) The Other column represents our shared services function, which provides administrative and other support to the Company. Certain costs incurred by this function are not allocated.

Regulated Transmission and Storage Segment Overview

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking and lending arrangements and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline. Lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands. Gross profit earned from our Mid-Tex Division and through certain other transportation and storage services is subject to traditional ratemaking governed by the RRC. Rates are updated through periodic formal rate proceedings and filings made under Texas' Gas Reliability Infrastructure Program (GRIP). GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years. Atmos Pipeline — Texas' existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates with minimal regulation.

These operations include one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Nine basins located in Texas are believed to contain a substantial portion of the nation's remaining onshore natural gas reserves. This pipeline system provides access to all of these basins.

Regulated Transmission and Storage Sales and Statistical Data

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
CUSTOMERS, end of year					
Industrial	71	65	68	62	65
Other	156	176	168	189	196
Total	227	241	236	251	261
PIPELINE TRANSPORTATION VOLUMES — MMcf(1)	620,904	634,885	706,132	782,876	699,006
OPERATING REVENUES (000's)(1)	$219,373	$203,013	$209,658	$195,917	$163,229
Employees, at year end	64	62	62	60	54

(1) Transportation volumes and operating revenues reflect segment operations, including intercompany sales and transportation amounts.

Nonregulated Segment Overview

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin. Certain of these arrangements are with regulatory affiliates, which have been approved by applicable state regulatory commissions.

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials) have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher natural gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. Volatility could also impact the basis differentials we capture in our delivered gas activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could impact the amount of cash required to collateralize our risk management liabilities.

Nonregulated Sales and Statistical Data

	Fiscal Year Ended September 30				
	2011	2010	2009	2008	2007
CUSTOMERS, end of year					
Industrial	697	652	631	624	677
Municipal	65	61	63	55	68
Other	362	339	321	312	281
Total	1,124	1,052	1,015	991	1,026
INVENTORY STORAGE BALANCE — Bcf	15.7	17.9	19.9	12.4	21.3
NONREGULATED DELIVERED GAS SALES VOLUMES — MMcf[1]	446,903	420,203	441,081	457,952	423,895
OPERATING REVENUES (000's)[1]	$2,024,893	$2,146,658	$2,283,988	$4,117,299	$2,901,879

(1) Sales volumes reflect segment operations, including intercompany sales and transportation amounts.

Ratemaking Activity

Overview

The method of determining regulated rates varies among the states in which our natural gas distribution divisions operate. The regulatory authorities have the responsibility of ensuring that utilities in their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on their investment. Generally, each regulatory authority reviews rate requests and establishes a rate structure intended to generate revenue sufficient to cover the costs of conducting business and to provide a reasonable return on invested capital.

Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins. Atmos Energy has annual ratemaking mechanisms in place in three states that provide for an annual rate review and adjustment to rates for approximately 73 percent of our gross margin. We also have accelerated recovery of capital for approximately 11 percent of our gross margin. Combined, we have rate structures with accelerated recovery of all or a portion of our expenditures for approximately 84 percent of our gross margin. Additionally, we have WNA mechanisms in eight states that serve to minimize the effects of weather on approximately 94 percent of our gross margin. Finally, we have the ability to recover the gas cost portion of bad debts for approximately 73 percent of our gross margin. These mechanisms work in tandem to provide substantial insulation from volatile margins, both for the Company and our customers.

We will also continue to address various rate design changes, including the recovery of bad debt gas costs and inclusion of other taxes in gas costs in future rate filings. These design changes would address cost variations that are related to pass-through energy costs beyond our control.

Although substantial progress has been made in recent years by improving rate design across Atmos Energy's operating areas, potential changes in federal energy policy and adverse economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors.

Recent Ratemaking Activity

Substantially all of our natural gas distribution revenues in the fiscal years ended September 30, 2011, 2010 and 2009 were derived from sales at rates set by or subject to approval by local or state authorities. Net operating income increases resulting from ratemaking activity totaling $72.4 million, $56.8 million and $54.4 million, became effective in fiscal 2011, 2010 and 2009 as summarized below:

Rate Action	Annual Increase to Operating Income For the Fiscal Year Ended September 30 2011	2010	2009
		(In thousands)	
Rate case filings	$20,502	$23,663	$ 2,959
Infrastructure programs	15,033	18,989	12,049
Annual rate filing mechanisms	35,216	13,757	38,764
Other ratemaking activity	1,675	392	631
	$72,426	$56,801	$54,403

Additionally, the following ratemaking efforts were initiated during fiscal 2011 but had not been completed as of September 30, 2011:

Division	Rate Action	Jurisdiction	Operating Income Requested
			(In thousands)
Kentucky/Mid-States	PRP(1)(2)	Georgia	$1,192
	PRP(1)(3)	Kentucky	2,529
Mississippi	Stable Rate Filing	Mississippi	5,303
West Texas & Lubbock Environs	Rate Case(4)	Railroad Commission of Texas (RRC)	545
			$9,569

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) The Georgia Commission issued a final order on October 5, 2011 approving a $1.2 million increase to operating income.

(3) The Kentucky Commission approved an increase of $2.5 million effective October 1, 2011.

(4) On September 30, 2011 the Company and Commission Staff signed a settlement and submitted to the Commission for their approval.

Our recent ratemaking activity is discussed in greater detail below.

Rate Case Filings

A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a "show cause" action. Adequate rates are intended to provide for recovery of the Company's costs as well as a fair rate of return to our shareholders and ensure that we continue to safely deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate cases:

Division	State	Increase in Annual Operating Income (In thousands)	Effective Date
2011 Rate Case Filings:			
West Texas — Amarillo Environs	Texas	$ 78	07/26/2011
Atmos Pipeline — Texas	Texas	20,424	05/01/2011
Total 2011 Rate Case Filings		$20,502	
2010 Rate Case Filings:			
Kentucky/Mid-States	Missouri	$ 3,977	09/01/2010
Colorado-Kansas	Kansas	3,855	08/01/2010
Kentucky/Mid-States	Kentucky	6,636	06/01/2010
Kentucky/Mid-States	Georgia	2,935	03/31/2010
Mid-Tex	Texas(1)	2,963	01/26/2010
Colorado-Kansas	Colorado	1,900	01/04/2010
Kentucky/Mid-States	Virginia	1,397	11/23/2009
Total 2010 Rate Case Filings		$23,663	
2009 Rate Case Filings:			
Kentucky/Mid-States	Tennessee	$ 2,513	04/01/2009
West Texas	Texas	446	Various
Total 2009 Rate Case Filings		$ 2,959	

(1) In its final order, the RRC approved a $3.0 million increase in operating income from customers in the Dallas & Environs portion of the Mid-Tex Division. Operating income should increase $0.2 million, net of the GRIP 2008 rates that will be superseded. The ruling also provided for regulatory accounting treatment for certain costs related to storage assets and costs moving from our Mid-Tex Division within our natural gas distribution segment to our regulated transmission and storage segment.

Infrastructure Programs

As discussed above in "Natural Gas Distribution Segment Overview," infrastructure programs such as GRIP allow natural gas distribution companies the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. We currently have infrastructure programs in Texas, Georgia, Missouri and Kentucky. The following table summarizes our infrastructure program filings with effective dates during the fiscal years ended September 30, 2011, 2010 and 2009:

Division	Period End	Incremental Net Utility Plant Investment	Increase in Annual Operating Income	Effective Date
		(In thousands)	(In thousands)	
2011 Infrastructure Programs:				
Atmos Pipeline — Texas	12/2010	$ 72,980	$12,605	07/26/2011
Mid-Tex/Environs	12/2010	107,840	576	06/27/2011
West Texas/Lubbock & WT Cities Environs	12/2010	17,677	343	06/01/2011
Kentucky/Mid-States-Kentucky (1)	09/2011	3,329	468	06/01/2011
Kentucky/Mid-States-Missouri(2)	09/2010	2,367	277	02/14/2011
Kentucky/Mid-States-Georgia(1)	09/2009	5,359	764	10/01/2010
Total 2011 Infrastructure Programs		$209,552	$15,033	
2010 Infrastructure Programs:				
Mid-Tex(3)	12/2009	$ 16,957	$ 2,983	09/01/2010
West Texas	12/2009	19,158	363	06/14/2010
Atmos Pipeline — Texas	12/2009	95,504	13,405	04/20/2010
Kentucky/Mid-States-Missouri(2)	06/2009	3,578	563	03/02/2010
Colorado-Kansas-Kansas(4)	08/2009	6,917	766	12/12/2009
Kentucky/Mid-States-Georgia(1)	09/2008	6,327	909	10/01/2009
Total 2010 Infrastructure Programs		$148,441	$18,989	
2009 Infrastructure Programs:				
Mid-Tex(5)	12/2008	$105,777	$ 2,732	09/09/2009
Atmos Pipeline — Texas	12/2008	51,308	6,342	04/28/2009
Mid-Tex(3)	12/2007	57,385	1,837	01/26/2009
Kentucky/Mid-States-Missouri(2)	03/2008	3,367	408	11/04/2008
Kentucky/Mid-States-Georgia(1)	09/2007	748	198	10/01/2008
West Texas(6)	2007/08	27,425	532	Various
Total 2009 Infrastructure Programs		$246,010	$12,049	

(1) The Pipeline Replacement Program (PRP) surcharge relates to a long-term cast iron replacement program.

(2) Infrastructure System Replacement Surcharge (ISRS) relates to maintenance capital investments made since the previous rate case.

(3) Increase relates to the City of Dallas and Environs areas of the Mid-Tex Division.

(4) Gas System Reliability Surcharge (GSRS) relates to safety related investments made since the previous rate case.

(5) Increase relates only to the City of Dallas area of the Mid-Tex Division.

(6) The West Texas Division files GRIP applications related only to the Lubbock Environs and the West Texas Cities Environs. GRIP implemented for this division include investments that related to both calendar years 2007 and 2008. The incremental investment is based on system-wide plant and additional annual operating revenue is applicable to environs customers only.

Annual Rate Filing Mechanisms

As an instrument to reduce regulatory lag, annual rate filing mechanisms allow us to refresh our rates on a periodic basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. As discussed above in "Natural Gas Distribution Segment Overview," we currently have annual rate filing mechanisms in our Louisiana and Mississippi divisions and in significant portions of our Mid-Tex and West Texas divisions. These mechanisms are referred to as rate review mechanisms in our Mid-Tex and West Texas divisions, stable rate filings in the Mississippi Division and the rate stabilization clause in the Louisiana Division. The following table summarizes filings made under our various annual rate filing mechanisms:

Division	Jurisdiction	Test Year Ended	Increase (Decrease) in Annual Operating Income	Effective Date
			(In thousands)	
2011 Filings:				
Mid-Tex	Settled Cities	12/31/2010	$ 5,126	09/27/2011
Mid-Tex	Dallas	12/31/2010	1,084	09/27/2011
West Texas	Lubbock	12/31/2010	319	09/08/2011
West Texas	Amarillo	12/31/2010	(492)	08/01/2011
Louisiana	LGS	12/31/2010	4,109	07/01/2011
Mid-Tex	Dallas	12/31/2010	1,598	07/01/2011
Louisiana	TransLa	09/30/2010	350	04/01/2011
Mid-Tex	Settled Cities	12/31/2009	23,122	10/01/2010
Total 2011 Filings			$35,216	
2010 Filings:				
West Texas	Lubbock	12/31/2009	$ (902)	09/01/2010
West Texas	WT Cities	12/31/2009	700	08/15/2010
West Texas	Amarillo	12/31/2009	1,200	08/01/2010
Louisiana	LGS	12/31/2009	3,854	07/01/2010
Louisiana	TransLa	09/30/2009	1,733	04/01/2010
Mississippi	Mississippi	06/30/2009	3,183	12/15/2009
West Texas	Lubbock	12/31/2008	2,704	10/01/2009
West Texas	Amarillo	12/31/2008	1,285	10/01/2009
Total 2010 Filings			$13,757	
2009 Filings:				
Mid-Tex	Settled Cities	12/31/2008	$ 1,979	08/01/2009
West Texas	WT Cities	12/31/2008	6,599	08/01/2009
Louisiana	LGS	12/31/2008	3,307	07/01/2009
Louisiana	TransLa	09/30/2008	611	04/01/2009
Mississippi	Mississippi	06/30/2008	—	N/A
Mid-Tex	Settled Cities	12/31/2007	21,800	11/08/2008
West Texas	WT Cities	12/31/2007	4,468	11/20/2008
Total 2009 Filings			$38,764	

In June 2011, we reached an agreement with the City of Dallas to enter into the DARR. This rate review provides for an annual rate review without the necessity of filing a general rate case. The first filing made under this mechanism will be in January 2012.

In August 2010, we reached an agreement to extend the RRM in our Mid-Tex Division for an additional two-year period beginning October 1, 2010; however, the Mid-Tex Division will be required to file a general system-wide rate case on or before June 1, 2013. This extension provides for an annual rate adjustment to reflect changes in the Mid-Tex Division's costs of service and additions to capital investment from year to year, without the necessity of filing a general rate case.

The settlement also allows us to expand our existing program to replace steel service lines in the Mid-Tex Division's natural gas delivery system. On October 13, 2010, the City of Dallas approved the recovery of the return, depreciation and taxes associated with the replacement of 100,000 steel service lines across the Mid-Tex Division by September 30, 2012. The RRM in the Mid-Tex Division was entered into as a result of a settlement in the September 20, 2007 Statement of Intent case filed with all Mid-Tex Division cities. Of the 440 incorporated cities served by the Mid-Tex Division, 439 of these cities are part of the RRM process.

The West Texas RRM was entered into in August 2008 as a result of a settlement with the West Texas Coalition of Cities. The Lubbock and Amarillo RRMs were entered into in the spring of 2009. The West Texas Coalition of Cities agreed to extend its RRM for one additional cycle as part of the settlement of this fiscal year's filing.

During fiscal 2011, the RRC's Division of Public Safety issued a new rule requiring natural gas distribution companies to develop and implement a risk-based program for the renewal or replacement of distribution facilities, including steel service lines. The rule allows for the deferral of all expense associated with capital expenditures incurred pursuant to this rule, including the recording of interest on the deferred expenses.

Other Ratemaking Activity

The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2011, 2010 and 2009:

Division	Jurisdiction	Rate Activity	Increase in Annual Operating Income	Effective Date
			(In thousands)	
2011 Other Rate Activity:				
West Texas	Triangle	Special Contract	$ 641	07/01/2011
Colorado-Kansas	Kansas	Ad Valorem(1)	685	01/01/2011
Colorado-Kansas	Colorado	AMI(2)	349	12/01/2010
Total 2011 Other Rate Activity			$1,675	
2010 Other Rate Activity:				
Colorado-Kansas	Kansas	Ad Valorem(1)	$ 392	01/05/2010
Total 2010 Other Rate Activity			$ 392	
2009 Other Rate Activity:				
Colorado-Kansas	Kansas	Tax Surcharge(3)	$ 631	02/01/2009
Total 2009 Other Rate Activity			$ 631	

(1) The Ad Valorem filing relates to a collection of property taxes in excess of the amount included in our Kansas service area's base rates.

(2) Automated Meter Infrastructure (AMI) relates to a pilot program in the Weld County area of our Colorado service area.

(3) In the state of Kansas, the tax surcharge represents a true-up of ad valorem taxes paid versus what is designed to be recovered through base rates.

Other Regulation

Each of our natural gas distribution divisions is regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our gas distribution facilities. In addition, our distribution operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with, and are operated in substantial conformity with, applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites in Tennessee, Iowa and Missouri.

The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through our Atmos Pipeline — Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC. Additionally, the FERC has regulatory authority over the sale of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity, as well as authority to detect and prevent market manipulation and to enforce compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations.

Competition

Although our natural gas distribution operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets.

Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business.

Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services. The increased competition has reduced margins most notably on its high-volume accounts.

Employees

At September 30, 2011, we had 4,949 employees, consisting of 4,817 employees in our regulated operations and 132 employees in our nonregulated operations.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, and other forms that we file with or furnish to the Securities and Exchange Commission (SEC) are available free of charge at our website, *www.atmosenergy.com*, under

"Publications and Filings" under the "Investors" tab, as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address and telephone number appearing below:

Shareholder Relations
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205
972-855-3729

Corporate Governance

In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer during fiscal 2011, Kim R. Cocklin, certified to the New York Stock Exchange that he was not aware of any violations by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of our website. We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. ***Risk Factors.***

Our financial and operating results are subject to a number of risk factors, many of which are not within our control. Although we have tried to discuss key risk factors below, please be aware that other or new risks may prove to be important in the future. Investors should carefully consider the following discussion of risk factors as well as other information appearing in this report. These factors include the following:

Further disruptions in the credit markets could limit our ability to access capital and increase our costs of capital.

We rely upon access to both short-term and long-term credit markets to satisfy our liquidity requirements. The global credit markets have experienced significant disruptions and volatility during the last few years to a greater degree than has been seen in decades. In some cases, the ability or willingness of traditional sources of capital to provide financing has been reduced.

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation, Moody's Investors Services, Inc. and Fitch Ratings, Ltd. If adverse credit conditions were to cause a significant limitation on our access to the private and public credit markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the three credit rating agencies. Such a downgrade could further limit our access to public and/or private credit markets and increase the costs of borrowing under each source of credit.

Further, if our credit ratings were downgraded, we could be required to provide additional liquidity to our nonregulated segment because the commodity financial instruments markets could become unavailable to us. Our nonregulated segment depends primarily upon a committed credit facility to finance its working capital needs, which it uses primarily to issue standby letters of credit to its natural gas suppliers. A significant reduction in the availability of this facility could require us to provide extra liquidity to support its operations or reduce some of the activities of our nonregulated segment. Our ability to provide extra liquidity is limited by the terms of our existing lending arrangements with AEH, which are subject to annual approval by one state regulatory commission.

While we believe we can meet our capital requirements from our operations and the sources of financing available to us, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near-term. The future effects on our business, liquidity and financial results of a further deterioration of current conditions in the credit markets could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate.

The continuation of recent economic conditions could adversely affect our customers and negatively impact our financial results.

The slowdown in the U.S. economy in the last few years, together with increased mortgage defaults and significant decreases in the values of homes and investment assets, has adversely affected the financial resources of many domestic households. It is unclear whether the administrative and legislative responses to these conditions will be successful in improving current economic conditions, including the lowering of current high unemployment rates across the U.S. As a result, our customers may seek to use even less gas and it may become more difficult for them to pay their gas bills. This may slow collections and lead to higher than normal levels of accounts receivable. This in turn could increase our financing requirements and bad debt expense. Additionally, our industrial customers may seek alternative energy sources, which could result in lower sales volumes.

The costs of providing pension and postretirement health care benefits and related funding requirements are subject to changes in pension fund values, changing demographics and fluctuating actuarial assumptions and may have a material adverse effect on our financial results. In addition, the passage of the Health Care Reform Act in 2010 could significantly increase the cost of the health care benefits for our employees.

We provide a cash-balance pension plan and postretirement healthcare benefits to eligible full-time employees. Our costs of providing such benefits and related funding requirements are subject to changes in the market value of the assets funding our pension and postretirement healthcare plans. The fluctuations over the last few years in the values of investments that fund our pension and postretirement healthcare plans may significantly differ from or alter the values and actuarial assumptions we use to calculate our future pension plan expense and postretirement healthcare costs and funding requirements under the Pension Protection Act. Any significant declines in the value of these investments could increase the expenses of our pension and postretirement healthcare plans and related funding requirements in the future. Our costs of providing such benefits and related funding requirements are also subject to changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five to ten years, as well as various actuarial calculations and assumptions, which may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates and interest rates and other factors. Also, our costs of providing such benefits are subject to the continuing recovery of these costs through rates.

In addition, the costs of providing health care benefits to our employees could significantly increase over the next five to ten years. Although the full effects of the Health Care Reform Act should not impact the Company until 2014, the future cost of compliance with the provisions of this legislation is difficult to measure at this time.

Our operations are exposed to market risks that are beyond our control which could adversely affect our financial results and capital requirements.

Our risk management operations are subject to market risks beyond our control, including market liquidity, commodity price volatility caused by market supply and demand dynamics and counterparty creditworthiness. Although we maintain a risk management policy, we may not be able to completely offset the price risk associated with volatile gas prices, particularly in our nonregulated business segments, which could lead to volatility in our earnings.

Physical trading in our nonregulated business segments also introduces price risk on any net open positions at the end of each trading day, as well as volatility resulting from intra-day fluctuations of gas prices and the potential for daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is hedged. The determination of our net open position as of the end of any particular trading day requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of such day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Although we manage our business to maintain no open positions, there are times when limited net open positions related to our physical storage may occur on a short-term basis. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner before the open positions can be closed.

Further, the timing of the recognition for financial accounting purposes of gains or losses resulting from changes in the fair value of derivative financial instruments designated as hedges usually does not match the timing of the economic profits or losses on the item being hedged. This volatility may occur with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated. Also, if the local physical markets in which we trade do not move consistently with the NYMEX futures market upon which most of our commodity derivative financial instruments are valued, we could experience increased volatility in the financial results of our nonregulated segment.

Our nonregulated segment manages margins and limits risk exposure on the sale of natural gas inventory or the offsetting fixed-price purchase or sale commitments for physical quantities of natural gas through the use of a variety of financial instruments. However, contractual limitations could adversely affect our ability to withdraw gas from storage, which could cause us to purchase gas at spot prices in a rising market to obtain sufficient volumes to fulfill customer contracts. We could also realize financial losses on our efforts to limit risk as a result of volatility in the market prices of the underlying commodities or if a counterparty fails to perform under a contract. Any significant tightening of the credit markets could cause more of our counterparties to fail to perform than expected. In addition, adverse changes in the creditworthiness of our counterparties could limit the level of trading activities with these parties and increase the risk that these parties may not perform under a contract. These circumstances could also increase our capital requirements.

We are also subject to interest rate risk on our borrowings. In recent years, we have been operating in a relatively low interest-rate environment compared to historical norms for both short and long-term interest rates. However, increases in interest rates could adversely affect our future financial results.

We are subject to state and local regulations that affect our operations and financial results.

Our natural gas distribution and regulated transmission and storage segments are subject to various regulated returns on our rate base in each jurisdiction in which we operate. We monitor the allowed rates of return and our effectiveness in earning such rates and initiate rate proceedings or operating changes as we believe they are needed. In addition, in the normal course of business in the regulatory environment, assets may be placed in service and historical test periods established before rate cases can be filed that could result in an adjustment of our allowed returns. Once rate cases are filed, regulatory bodies have the authority to suspend implementation of the new rates while studying the cases. Because of this process, we must suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as "regulatory lag." Rate cases also involve a risk of rate reduction, because once rates have been approved, they are still subject to challenge for their reasonableness by appropriate regulatory authorities. In addition, regulators may review our purchases of natural gas and can adjust the amount of our gas costs that we pass through to our customers. Finally, our debt and equity financings are also subject to approval by regulatory commissions in several states, which could limit our ability to access or take advantage of rapid changes in the capital markets.

We may experience increased federal, state and local regulation of the safety of our operations.

We are committed to constantly monitoring and maintaining our pipeline and distribution system to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 76,000 miles of pipeline and distribution lines. The pipeline replacement programs currently underway in several of our divisions typify the preventive maintenance and continual renewal that we perform on our natural gas distribution system in the 12 states in which we currently operate. The safety and protection of the public, our customers and our employees is our top priority. However, due primarily to the recent unfortunate pipeline incident in California, we anticipate companies in the natural gas distribution business may be subjected to even greater federal, state and local oversight of the safety of their operations in the future. Although we believe these costs are ultimately recoverable through our rates, costs of complying with such increased regulations may have at least a short-term adverse impact on our operating costs and financial results.

Some of our operations are subject to increased federal regulatory oversight that could affect our operations and financial results.

FERC has regulatory authority that affects some of our operations, including sales of natural gas in the wholesale gas market and the use and release of interstate pipeline and storage capacity. Under legislation passed by Congress in 2005, FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERC's other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. We are currently under investigation by FERC for possible violations of its posting and competitive bidding regulations for pre-arranged released firm capacity on interstate natural gas pipelines. Should FERC conclude that we have committed such violations of its regulations and levies substantial fines and/or penalties against us, our business, financial condition or financial results could be adversely affected. Although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results.

We are subject to environmental regulations which could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations.

Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change.

There have been a number of new federal and state legislative and regulatory initiatives proposed in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. For example, in June 2009, the U.S. House of Representatives approved *The American Clean Energy and Security Act of 2009*, also known as the Waxman-Markey bill or "cap and trade" bill. However, neither this bill nor a related bill in the U.S. Senate, the Clean Energy and Emissions Power Act was passed by Congress. The adoption of this type of legislation by Congress or similar legislation by states or the adoption of related regulations by federal or state governments mandating a substantial reduction in greenhouse gas emissions in the future could have far-reaching and significant impacts on the energy industry. Such new legislation or regulations could result in increased compliance costs for us or additional operating restrictions on our business, affect the demand for natural gas or impact the prices we charge to our customers. At this time, we cannot predict the potential impact of such laws or regulations that may be adopted on our future business, financial condition or financial results.

The concentration of our distribution, pipeline and storage operations in the State of Texas exposes our operations and financial results to economic conditions and regulatory decisions in Texas.

Over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general and regulatory decisions by state and local regulatory authorities in Texas.

Adverse weather conditions could affect our operations or financial results.

Since the 2006-2007 winter heating season, we have had weather-normalized rates for over 90 percent of our residential and commercial meters, which has substantially mitigated the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather — normalized rates could have an adverse effect on our operations and financial results. In addition, our natural gas distribution and regulated transmission and storage operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Sustained cold weather could adversely affect our nonregulated operations as we may be required to purchase gas at spot rates in a rising market to obtain sufficient volumes to fulfill some customer contracts. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our natural gas distribution and regulated transmission and storage operations.

Inflation and increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.

Inflation has caused increases in some of our operating expenses and has required assets to be replaced at higher costs. We have a process in place to continually review the adequacy of our natural gas distribution gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates and intend to continue to do so. However, the ability to control expenses is an important factor that could impact future financial results.

Rapid increases in the costs of purchased gas would cause us to experience a significant increase in short-term debt. We must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our natural gas distribution collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater collection efforts and increased bad debt expense.

Our growth in the future may be limited by the nature of our business, which requires extensive capital spending.

We must continually build additional capacity in our natural gas distribution system to enable us to serve any growth in the number of our customers. The cost of adding this capacity may be affected by a number of factors, including the general state of the economy and weather. In addition, although we should ultimately recover the cost of the expenditures through rates, we must make significant capital expenditures during the next fiscal year in executing our steel service line replacement program in the Mid-Tex Division. Our cash flows from operations generally are sufficient to supply funding for all our capital expenditures, including the financing of the costs of new construction along with capital expenditures necessary to maintain our existing natural gas system. Due to the timing of these cash flows and capital expenditures, we often must fund at least a portion of these costs through borrowing funds from third party lenders, the cost and availability of which is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

Our operations are subject to increased competition.

In residential and commercial customer markets, our natural gas distribution operations compete with other energy products, such as electricity and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This could adversely impact our business if, as a result, our customer growth slows, reducing our ability to make capital expenditures, or if our customers further conserve their use of gas, resulting in reduced gas purchases and customer billings.

In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our regulated transmission and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, in the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business. Within our nonregulated operations, AEM competes with other natural gas marketers to provide natural gas management and other related services primarily to smaller customers requiring higher levels of balancing, scheduling and other related management services. AEM has experienced increased competition in recent years primarily from investment banks and major integrated oil and natural gas companies who offer lower cost, basic services.

Distributing and storing natural gas involve risks that may result in accidents and additional operating costs.

Our natural gas distribution business involves a number of hazards and operating risks that cannot be completely avoided, such as leaks, accidents and operational problems, which could cause loss of human life, as well as substantial financial losses resulting from property damage, damage to the environment and to our operations. We do have liability and property insurance coverage in place for many of these hazards and risks. However, because our pipeline, storage and distribution facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by insurance, our operations or financial results could be adversely affected.

Natural disasters, terrorist activities or other significant events could adversely affect our operations or financial results.

Natural disasters are always a threat to our assets and operations. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Also, companies in our industry may face a heightened risk of exposure to actual acts of terrorism, which could subject our operations to increased risks. As a result, the availability of insurance covering such risks may be more limited, which could increase the risk that an event could adversely affect our operations or financial results.

ITEM 1B. *Unresolved Staff Comments.*

Not applicable.

ITEM 2. *Properties.*

Distribution, transmission and related assets

At September 30, 2011, our natural gas distribution segment owned an aggregate of 70,869 miles of underground distribution and transmission mains throughout our gas distribution systems. These mains are located on easements or rights-of-way which generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. Our regulated transmission and storage segment owned 5,861 miles of gas transmission and gathering lines and our nonregulated segment owned 105 miles of gas transmission and gathering lines.

Storage Assets

We own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes certain information regarding our underground gas storage facilities at September 30, 2011:

State	Usable Capacity (Mcf)	Cushion Gas (Mcf)[1]	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
Natural Gas Distribution Segment				
Kentucky	4,442,696	6,322,283	10,764,979	109,100
Kansas	3,239,000	2,300,000	5,539,000	45,000
Mississippi	2,211,894	2,442,917	4,654,811	48,000
Georgia	490,000	10,000	500,000	30,000
Total	10,383,590	11,075,200	21,458,790	232,100
Regulated Transmission and Storage Segment — Texas	46,143,226	15,878,025	62,021,251	1,235,000
Nonregulated Segment				
Kentucky	3,492,900	3,295,000	6,787,900	71,000
Louisiana	438,583	300,973	739,556	56,000
Total	3,931,483	3,595,973	7,527,456	127,000
Total	60,458,299	30,549,198	91,007,497	1,594,100

(1) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity at September 30, 2011:

Segment	Division/Company	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MDWQ)[1]
Natural Gas Distribution Segment[2]			
	Colorado-Kansas Division	4,243,909	108,039
	Kentucky/Mid-States Division	16,835,380	444,339
	Louisiana Division	2,643,192	161,473
	Mississippi Division	3,875,429	165,402
	West Texas Division	2,375,000	81,000
Total		29,972,910	960,253
Nonregulated Segment			
	Atmos Energy Marketing, LLC	8,026,869	250,937
	Trans Louisiana Gas Pipeline, Inc.	1,674,000	67,507
Total		9,700,869	318,444
Total Contracted Storage Capacity		39,673,779	1,278,697

(1) Maximum daily withdrawal quantity (MDWQ) amounts will fluctuate depending upon the season and the month. Unless otherwise noted, MDWQ amounts represent the MDWQ amounts as of November 1, which is the beginning of the winter heating season.

(2) On October 1, 2011, our Mid-Tex Division signed a new storage contract with a maximum storage quantity of 500,000 MMBtu and maximum daily withdrawal quantity of 50,000 MMBtu.

Offices

Our administrative offices and corporate headquarters are consolidated in a leased facility in Dallas, Texas. We also maintain field offices throughout our distribution system, the majority of which are located in leased facilities. The headquarters for our nonregulated operations are in Houston, Texas, with offices in Houston and other locations, primarily in leased facilities.

ITEM 3. *Legal Proceedings.*

See Note 13 to the consolidated financial statements.

PART II

ITEM 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Our stock trades on the New York Stock Exchange under the trading symbol "ATO." The high and low sale prices and dividends paid per share of our common stock for fiscal 2011 and 2010 are listed below. The high and low prices listed are the closing NYSE quotes, as reported on the NYSE composite tape, for shares of our common stock:

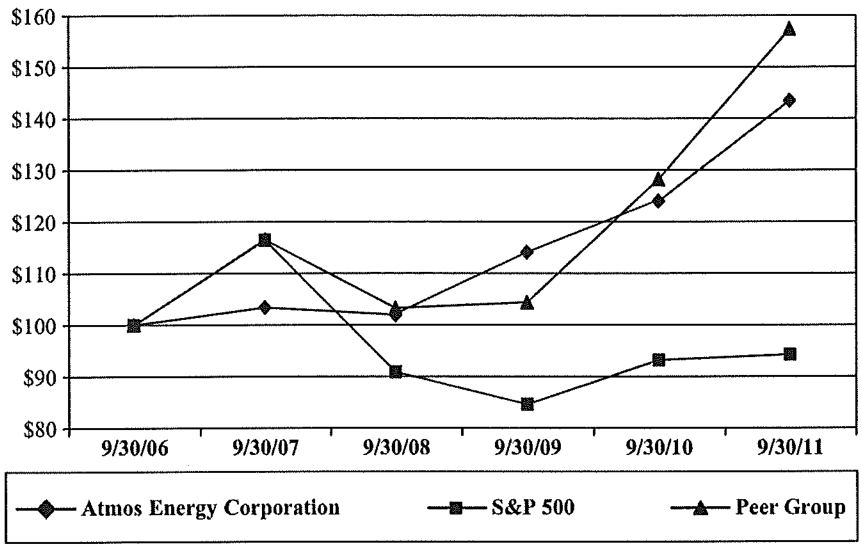
	Fiscal 2011			Fiscal 2010		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$31.72	$29.10	$.340	$30.06	$27.39	$.335
March 31	34.98	31.51	.340	29.52	26.52	.335
June 30	34.94	31.34	.340	29.98	26.41	.335
September 30	34.32	28.87	.340	29.81	26.82	.335
			$1.36			$1.34

Dividends are payable at the discretion of our Board of Directors out of legally available funds. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2011 was 18,746. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2011 that were not registered under the Securities Act of 1933, as amended.

Performance Graph

The performance graph and table below compares the yearly percentage change in our total return to shareholders for the last five fiscal years with the total return of the Standard and Poor's 500 Stock Index and the cumulative total return of a customized peer company group, the Comparison Company Index, which is comprised of natural gas distribution companies with similar revenues, market capitalizations and asset bases to that of the Company. The graph and table below assume that $100.00 was invested on September 30, 2006 in our common stock, the S&P 500 Index and in the common stock of the companies in the Comparison Company Index, as well as a reinvestment of dividends paid on such investments throughout the period.

Comparison of Five-Year Cumulative Total Return among Atmos Energy Corporation, S&P 500 Index and Comparison Company Indices



	Cumulative Total Return					
	9/30/06	9/30/07	9/30/08	9/30/09	9/30/10	9/30/11
Atmos Energy Corporation	100.00	103.36	101.92	113.82	123.97	143.45
S&P 500	100.00	116.44	90.85	84.58	93.17	94.24
Peer Group	100.00	116.52	103.24	104.34	128.20	157.38

The Comparison Company Index contains a hybrid group of utility companies, primarily natural gas distribution companies, recommended by a global management consulting firm and approved by the Board of Directors. The companies included in the index are AGL Resources Inc., CenterPoint Energy Resources Corporation, CMS Energy Corporation, EQT Corporation, Integrys Energy Group, Inc., National Fuel Gas, Nicor Inc., NiSource Inc., ONEOK Inc., Piedmont Natural Gas Company, Inc., Vectren Corporation and WGL Holdings, Inc.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2011.

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders:			
1998 Long-Term Incentive Plan	86,766	$22.16	319,700
Total equity compensation plans approved by security holders	86,766	22.16	319,700
Equity compensation plans not approved by security holders	—	—	—
Total	86,766	$22.16	319,700

ITEM 6. *Selected Financial Data.*

The following table sets forth selected financial data of the Company and should be read in conjunction with the consolidated financial statements included herein.

	Fiscal Year Ended September 30				
	2011[1]	2010	2009[1]	2008	2007[1]
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	$4,347,634	$4,719,835	$4,869,111	$7,117,837	$5,803,177
Gross profit	1,327,241	1,337,505	1,319,678	1,293,922	1,221,078
Operating expenses[1]	885,342	860,354	883,312	878,399	835,353
Operating income	441,899	477,151	436,366	415,523	385,725
Miscellaneous income (expense)	21,499	(156)	(3,067)	3,017	9,227
Interest charges	150,825	154,360	152,638	137,218	145,019
Income from continuing operations before income taxes	312,573	322,635	280,661	281,322	249,933
Income tax expense	113,689	124,362	97,362	107,837	89,105
Income from continuing operations	198,884	198,273	183,299	173,485	160,828
Income from discontinued operations, net of tax	8,717	7,566	7,679	6,846	7,664
Net income	$ 207,601	$ 205,839	$ 190,978	$ 180,331	$ 168,492
Weighted average diluted shares outstanding	90,652	92,422	91,620	89,941	87,486
Income per share from continuing operations — diluted	$ 2.17	$ 2.12	$ 1.98	$ 1.91	$ 1.82
Income per share from discontinued operations — diluted	0.10	0.08	0.09	0.08	0.09
Diluted net income per share	$ 2.27	$ 2.20	$ 2.07	$ 1.99	$ 1.91
Cash flows from operations	$ 582,844	$ 726,476	$ 919,233	$ 370,933	$ 547,095
Cash dividends paid per share	$ 1.36	$ 1.34	$ 1.32	$ 1.30	$ 1.28
Natural gas distribution throughput from continuing operations (MMcf)[2]	409,369	438,535	393,604	413,491	411,337
Natural gas distribution throughput from discontinued operations (MMcf)[2]	14,651	15,640	15,281	15,863	16,532
Total regulated transmission and storage transportation volumes (MMcf)[2]	435,012	428,599	528,689	595,542	505,493
Total nonregulated delivered gas sales volumes (MMcf)[2]	384,799	353,853	370,569	389,392	370,668
Financial Condition					
Net property, plant and equipment[5]	$5,147,918	$4,793,075	$4,439,103	$4,136,859	$3,836,836
Working capital[6]	143,355	(290,887)	91,519	78,017	149,217
Total assets	7,282,871	6,763,791	6,367,083	6,386,699	5,895,197
Short-term debt, inclusive of current maturities of long-term debt	208,830	486,231	72,681	351,327	154,430
Capitalization:					
Shareholders' equity	2,255,421	2,178,348	2,176,761	2,052,492	1,965,754
Long-term debt (excluding current maturities)	2,206,117	1,809,551	2,169,400	2,119,792	2,126,315
Total capitalization	4,461,538	3,987,899	4,346,161	4,172,284	4,092,069
Capital expenditures	622,965	542,636	509,494	472,273	392,435
Financial Ratios					
Capitalization ratio[3]	48.3%	48.7%	49.3%	45.4%	46.3%
Return on average shareholders' equity[4]	9.1%	9.1%	8.9%	8.8%	8.8%

(1) Financial results for fiscal years 2011, 2009 and 2007 include a $30.3 million, $5.4 million and a $6.3 million pre-tax loss for the impairment of certain assets.

(2) Net of intersegment eliminations.

(3) The capitalization ratio is calculated by dividing shareholders' equity by the sum of total capitalization and short-term debt, inclusive of current maturities of long-term debt.

(4) The return on average shareholders' equity is calculated by dividing current year net income by the average of shareholders' equity for the previous five quarters.

(5) Amount shown for fiscal 2011 are net of assets held for sale.

(6) Amount shown for fiscal 2011 includes assets held for sale.

ITEM 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

INTRODUCTION

This section provides management's discussion of the financial condition, changes in financial condition and results of operations of Atmos Energy Corporation and its consolidated subsidiaries with specific information on results of operations and liquidity and capital resources. It includes management's interpretation of our financial results, the factors affecting these results, the major factors expected to affect future operating results and future investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

Several factors exist that could influence our future financial performance, some of which are described in Item 1A above, "Risk Factors". They should be considered in connection with evaluating forward-looking statements contained in this report or otherwise made by or on behalf of us since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: our ability to continue to access the credit markets to satisfy our liquidity requirements; the impact of adverse economic conditions on our customers; increased costs of providing pension and postretirement health care benefits and increased funding requirements along with increased costs of health care benefits; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; regulatory trends and decisions, including the impact of rate proceedings before various state regulatory commissions; possible increased federal, state and local regulation of the safety of our operations; increased federal regulatory oversight and potential penalties; the impact of environmental regulations on our business; the impact of possible future additional regulatory and financial risks associated with global warming and climate change on our business; the concentration of our distribution, pipeline and storage operations in Texas; adverse weather conditions; the effects of inflation and changes in the availability and price of natural gas; the capital-intensive nature of our gas distribution business; increased competition from energy suppliers and alternative forms of energy; the inherent hazards and risks involved in operating our gas distribution business, natural disasters, terrorist activities or other events, and other risks and uncertainties discussed herein, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, fair value measurements, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Our critical accounting policies are reviewed by the Audit Committee periodically. Actual results may differ from estimates.

Regulation — Our natural gas distribution and regulated transmission and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. We meet the criteria established within accounting principles generally accepted in the United States of a cost-based, rate-regulated entity, which requires us to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in our financial statements in accordance with applicable authoritative accounting standards. We apply the provisions of this standard to our regulated operations and record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States are permitted to be capitalized or deferred on the balance sheet because it is probable they can be recovered through rates. Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our regulated operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

Revenue recognition — Sales of natural gas to our natural gas distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense.

On occasion, we are permitted to implement new rates that have not been formally approved by our regulatory authorities, which are subject to refund. We recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas costs through purchased gas cost adjustment mechanisms. Purchased gas cost adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility company's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of cost, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility company's other costs, (ii) represents a large component of the utility company's cost of service and (iii) is generally outside the control of the gas utility company. There is no gross profit generated through purchased gas cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all natural gas distribution sales to our customers fluctuate with the cost of gas that we purchase, our gross profit is generally not affected by fluctuations in the cost of gas as a result of the purchased gas cost adjustment mechanism. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our regulated transmission and storage and nonregulated segments are recognized in the period in which actual volumes are transported and storage services are provided.

Operating revenues for our nonregulated segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our natural gas marketing activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments.

Allowance for doubtful accounts — Accounts receivable arise from natural gas sales to residential, commercial, industrial, municipal and other customers. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Financial instruments and hedging activities — We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically use financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to meet the needs of our regulated and nonregulated businesses.

We record all of our financial instruments on the balance sheet at fair value as required by accounting principles generally accepted in the United States, with changes in fair value ultimately recorded in the income statement. The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

In our natural gas distribution segment, our customers are exposed to the effect of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season. The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk in this segment are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with accounting principles generally accepted in the United States. Accordingly, there is no earnings impact to our natural gas distribution segment as a result of the use of financial instruments.

Our nonregulated segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. We also perform asset optimization activities in which we seek to maximize the economic value associated with storage and transportation capacity we own or control in both our natural gas distribution and nonregulated businesses. As a result of these activities, our nonregulated operations are exposed to risks associated with changes in the market price of natural gas. We manage our exposure to the risk of natural gas price changes through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties.

In our nonregulated segment, we have designated the natural gas inventory held by this operating segment as the hedged item in a fair-value hedge. This inventory is marked to market at the end of each month based on the Gas Daily index, with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. The financial instruments associated with this natural gas inventory have been designated as fair-value hedges and are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial instruments designated against our physical inventory (NYMEX) and the market (spot) prices used to value our physical storage (Gas Daily) result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. The difference in the spot price used to value our physical inventory and the forward price used to value the related financial instruments can result in volatility in our reported income as a component of unrealized margins. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized. Over time, we expect gains and losses on the sale of storage gas inventory to be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

We have elected to treat fixed-price forward contracts used in our nonregulated segment to deliver gas as normal purchases and normal sales. As such, these deliveries are recorded on an accrual basis in accordance with our revenue recognition policy. Financial instruments used to mitigate the commodity price risk associated with these contracts have been designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on open financial instruments are recorded as a component of accumulated other comprehensive income and are recognized in earnings as a component of revenue when the hedged volumes are sold. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

We also use storage swaps and futures to capture additional storage arbitrage opportunities in our nonregulated segment that arise after the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt with Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designate these Treasury lock agreements as cash flow hedges at the time the agreements are executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements are recorded as a component of accumulated other comprehensive income (loss). The realized gain or loss recognized upon settlement of each Treasury lock agreement is initially recorded as a component of accumulated other comprehensive income (loss) and is recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness, to the extent incurred, is reported as a component of interest expense.

Impairment assessments — We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. As of September 30, 2011, we had no indefinite-lived intangible assets.

We annually evaluate our goodwill balances for impairment during our second fiscal quarter or as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. We have determined our reporting units to be each of our natural gas distribution divisions and wholly-owned subsidiaries and goodwill is allocated to the reporting units responsible for the acquisition that gave rise to the goodwill. The discounted cash flow calculations used to assess goodwill impairment are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

We annually assess whether the cost of our intangible assets subject to amortization or other long-lived assets is recoverable or that the remaining useful lives may warrant revision. We perform this assessment more frequently when specific events or circumstances have occurred that suggest the recoverability of the cost of the intangible and other long-lived assets is at risk.

When such events or circumstances are present, we assess the recoverability of these assets by determining whether the carrying value will be recovered through expected future cash flows from the operating division or subsidiary to which these assets relate. These cash flow projections consider various factors such as the timing of the future cash flows and the discount rate and are based upon the best information available at the time the estimate is made. Changes in these factors could materially affect the cash flow projections and result in the recognition of an impairment charge. An impairment charge is recognized as the difference between the carrying amount and the fair value if the sum of the undiscounted cash flows is less than the carrying value of the related asset.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis using a September 30 measurement date and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net periodic pension and postretirement benefit plan costs. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of our annual pension and postretirement plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan costs are not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years.

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

We estimate the assumed health care cost trend rate used in determining our postretirement net expense based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.

Actual changes in the fair market value of plan assets and differences between the actual and expected return on plan assets could have a material effect on the amount of pension costs ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement costs by approximately $1.9 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement costs by approximately $0.8 million.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Adverse developments in the global financial and credit markets in the last few years have made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. A further tightening of the credit markets could cause more of our counterparties to fail to perform. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

RESULTS OF OPERATIONS

Overview

Atmos Energy Corporation is involved in the distribution, marketing and transportation of natural gas. Accordingly, our results of operations are impacted by the demand for natural gas, particularly during the winter heating season, and the volatility of the natural gas markets. This generally results in higher operating revenues and net income during the period from October through March of each fiscal year and lower operating revenues and either lower net income or net losses during the period from April through September of each fiscal year. As a result of the seasonality of the natural gas industry, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 62 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years.

Additionally, the seasonality of our business impacts our working capital differently at various times during the year. Typically, our accounts receivable, accounts payable and short-term debt balances peak by the end of January and then start to decline, as customers begin to pay their winter heating bills. Gas stored underground, particularly in our natural gas distribution segment, typically peaks in November and declines as we utilize storage gas to serve our customers.

During fiscal 2011, we earned $207.6 million, or $2.27 per diluted share, which represents a one percent increase in net income and a three percent increase in diluted net income per share over fiscal 2010. During fiscal 2011, recent improvements in rate designs in our natural gas distribution segment and a successful regulatory outcome in our regulated transmission and storage segment offset a seven percent year-over-year decline in consolidated natural gas distribution throughput due to warmer weather and a 108 percent decrease in asset optimization margins as a result of weak natural gas market fundamentals. Results for fiscal 2011 were influenced by several non-recurring items, which increased diluted earnings per share by $0.03. The increase in fiscal 2011 earnings per share also reflects the favorable impact of our accelerated share buyback agreement initiated in the fourth quarter of fiscal 2010 and completed in the second quarter of fiscal 2011, which increased diluted earnings per share by $0.08.

On May 12, 2011, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals. Due to the pending sales transaction, the results of operations for these three service areas are shown in discontinued operations.

On June 10, 2011 we issued $400 million of 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks associated with the offering. Substantially all of the net proceeds of approximately $394 million were used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

During the year ended September 30, 2011, we executed on our strategy to streamline our credit facilities, as follows:

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.
- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased in fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.
- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

After giving effect to these changes, we now have $985 million of liquidity available to us from our commercial paper program and four committed credit facilities and have reduced our financing costs. We believe this availability provides sufficient liquidity to fund our working capital needs.

Consolidated Results

The following table presents our consolidated financial highlights for the fiscal years ended September 30, 2011, 2010 and 2009.

	For the Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Operating revenues	$4,347,634	$4,719,835	$4,869,111
Gross profit	1,327,241	1,337,505	1,319,678
Operating expenses	885,342	860,354	883,312
Operating income	441,899	477,151	436,366
Miscellaneous income (expense)	21,499	(156)	(3,067)
Interest charges	150,825	154,360	152,638
Income from continuing operations before income taxes	312,573	322,635	280,661
Income tax expense	113,689	124,362	97,362
Income from continuing operations	198,884	198,273	183,299
Income from discontinued operations, net of tax	8,717	7,566	7,679
Net income	$ 207,601	$ 205,839	$ 190,978
Diluted net income per share from continuing operations	$ 2.17	$ 2.12	$ 1.98
Diluted net income per share from discontinued operations	$ 0.10	$ 0.08	$ 0.09
Diluted net income per share	$ 2.27	$ 2.20	$ 2.07

Historically, our regulated operations arising from our natural gas distribution and regulated transmission and storage operations contributed 65 to 85 percent of our consolidated net income. Regulated operations contributed 104 percent, 81 percent and 83 percent to our consolidated net income for fiscal years 2011, 2010, and 2009. Our consolidated net income during the last three fiscal years was earned across our business segments as follows:

	For the Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands)		
Natural gas distribution segment	$162,718	$125,949	$116,807
Regulated transmission and storage segment	52,415	41,486	41,056
Nonregulated segment	(7,532)	38,404	33,115
Net income	$207,601	$205,839	$190,978

The following table segregates our consolidated net income and diluted earnings per share between our regulated and nonregulated operations:

	For the Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Regulated operations	$215,133	$167,435	$157,863
Nonregulated operations	(7,532)	38,404	33,115
Consolidated net income	$207,601	$205,839	$190,978
Diluted EPS from regulated operations	$ 2.35	$ 1.79	$ 1.71
Diluted EPS from nonregulated operations	(0.08)	0.41	0.36
Consolidated diluted EPS	$ 2.27	$ 2.20	$ 2.07

We reported net income of $207.6 million, or $2.27 per diluted share for the year ended September 30, 2011, compared with net income of $205.8 million or $2.20 per diluted share in the prior year. Income from continuing operations was $198.9 million, or $2.17 per diluted share compared with $198.3 million, or $2.12 per diluted share in the prior-year period. Income from discontinued operations was $8.7 million or $0.10 per diluted share for the year, compared with $7.6 million or $0.08 per diluted share in the prior year. Unrealized losses in our nonregulated operations during the current year reduced net income by $6.6 million or $0.07 per diluted share compared with net losses recorded in the prior year of $4.3 million, or $0.05 per diluted share. Additionally, net income in both periods was impacted by nonrecurring items. In the prior year, net income included the net positive impact of a state sales tax refund of $4.6 million, or $0.05 per diluted share. In the current year, net income includes the net positive impact of several one-time items totaling $3.2 million, or $0.03 per diluted share related to the following pre-tax amounts:

- $27.8 million favorable impact related to the cash gain recorded in association with the unwinding of two Treasury locks in conjunction with the cancellation of a planned debt offering in November 2011.
- $30.3 million unfavorable impact related to the non-cash impairment of certain assets in our nonregulated business.
- $5.0 million favorable impact related to the administrative settlement of various income tax positions.

Net income during fiscal 2010 increased eight percent over fiscal 2009. Net income from our regulated operations increased six percent during fiscal 2010. The increase primarily reflects colder than normal weather in most of our service areas during fiscal 2010 as well as the net favorable impact of various ratemaking activities in our natural gas distribution segment. Net income in our nonregulated operations increased $5.3 million during fiscal 2010 primarily due to the impact of unrealized margins. Non-cash, net unrealized losses totaled $4.3 million which reduced earnings per share by $0.05 per diluted share in fiscal 2010 compared to fiscal 2009, when net unrealized losses totaled $21.6 million, which reduced earnings per share by $0.23 per diluted share.

See the following discussion regarding the results of operations for each of our business operating segments.

Natural Gas Distribution Segment

The primary factors that impact the results of our natural gas distribution operations are our ability to earn our authorized rates of return, the cost of natural gas, competitive factors in the energy industry and economic conditions in our service areas.

Our ability to earn our authorized rates is based primarily on our ability to improve the rate design in our various ratemaking jurisdictions by reducing or eliminating regulatory lag and, ultimately, separating the recovery of our approved margins from customer usage patterns. Improving rate design is a long-term process and is further complicated by the fact that we operate in multiple rate jurisdictions. The "Ratemaking Activity" section of this Form 10-K describes our current rate strategy, progress towards implementing that strategy and recent ratemaking initiatives in more detail.

We are generally able to pass the cost of gas through to our customers without markup under purchased gas cost adjustment mechanisms; therefore the cost of gas typically does not have an impact on our gross profit as increases in the cost of gas are offset by a corresponding increase in revenues. Accordingly, we believe gross profit is a better indicator of our financial performance than revenues. However, gross profit in our Texas and Mississippi service areas include franchise fees and gross receipts taxes, which are calculated as a percentage of revenue (inclusive of gas costs). Therefore, the amount of these taxes included in revenues is influenced by the cost of gas and the level of gas sales volumes. We record the tax expense as a component of taxes, other than income. Although changes in revenue-related taxes arising from changes in gas costs affect gross profit, over time the impact is offset within operating income.

As discussed above, the cost of gas typically does not have a direct impact on our gross profit. However, higher gas costs may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. In addition, higher gas costs, as well as competitive factors in the industry and general economic conditions may cause customers to conserve or, in the case of industrial consumers, to use alternative energy sources. However, gas cost risk has been mitigated in recent years through improvements in rate design that allow us to collect from our customers the gas cost portion of our bad debt expense on approximately 73 percent of our residential and commercial margins.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa. The results of these operations have been separately reported in the following tables and exclude general corporate overhead and interest expense that would normally be allocated to these operations.

Review of Financial and Operating Results

Financial and operational highlights for our natural gas distribution segment for the fiscal years ended September 30, 2011, 2010 and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
	(In thousands, unless otherwise noted)				
Gross profit	$1,044,364	$1,022,011	$997,604	$ 22,353	$24,407
Operating expenses	706,363	711,842	719,626	(5,479)	(7,784)
Operating income	338,001	310,169	277,978	27,832	32,191
Miscellaneous income	16,557	1,567	6,002	14,990	(4,435)
Interest charges	115,802	118,319	123,863	(2,517)	(5,544)
Income from continuing operations before income taxes	238,756	193,417	160,117	45,339	33,300
Income tax expense	84,755	75,034	50,989	9,721	24,045
Income from continuing operations	154,001	118,383	109,128	35,618	9,255
Income from discontinued operations, net of tax	8,717	7,566	7,679	1,151	(113)
Net Income	$ 162,718	$ 125,949	$116,807	$ 36,769	$ 9,142
Consolidated natural gas distribution sales volumes from continuing operations — MMcf	281,466	313,888	273,555	(32,422)	40,333
Consolidated natural gas distribution transportation volumes from continuing operations — MMcf	127,903	124,647	120,049	3,256	4,598
Consolidated natural gas distribution throughput from continuing operations — MMcf	409,369	438,535	393,604	(29,166)	44,931
Consolidated natural gas distribution throughput from discontinued operations — MMcf	14,651	15,640	15,281	(989)	359
Total consolidated natural gas distribution throughput — MMcf	424,020	454,175	408,885	(30,155)	45,290
Consolidated natural gas distribution average transportation revenue per Mcf	$ 0.47	$ 0.47	$ 0.47	$ —	$ —
Consolidated natural gas distribution average cost of gas per Mcf sold	$ 5.30	$ 5.77	$ 6.95	$ (0.47)	$ (1.18)

The following table shows our operating income from continuing operations by natural gas distribution division, in order of total rate base, for the fiscal years ended September 30, 2011, 2010 and 2009. The presentation of our natural gas distribution operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
			(In thousands)		
Mid-Tex	$144,204	$134,655	$127,625	$ 9,549	$ 7,030
Kentucky/Mid-States	53,506	46,238	37,683	7,268	8,555
Louisiana	50,442	45,759	43,434	4,683	2,325
West Texas	29,686	33,509	23,338	(3,823)	10,171
Mississippi	26,338	26,441	21,287	(103)	5,154
Colorado-Kansas	25,920	24,543	20,580	1,377	3,963
Other	7,905	(976)	4,031	8,881	(5,007)
Total	$338,001	$310,169	$277,978	$27,832	$32,191

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

The $22.4 million increase in natural gas distribution gross profit primarily reflects a $40.4 million net increase in rate adjustments, primarily in the Mid-Tex, Louisiana, Kentucky and Kansas service areas.

These increases were partially offset by:

- $12.0 million decrease due to a seven percent decrease in consolidated throughput caused principally by lower residential and commercial consumption combined with warmer weather this fiscal year compared to the same period last year in most of our service areas.
- $8.1 million decrease in revenue-related taxes, primarily due to lower revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes, other than income decreased $5.5 million, primarily due to the following:

- $10.0 million decrease in taxes, other than income, due to lower revenue-related taxes.
- $6.4 million decrease in employee-related expenses.

These decreases were partially offset by:

- $5.4 million increase due to the absence of a state sales tax reimbursement received in the prior year.
- $11.8 million increase in depreciation and amortization expense.
- $1.8 million increase in vehicles and equipment expense.

Net income for this segment for the year-to-date period was also favorably impacted by a $21.8 million pre-tax gain recognized in March 2011 as a result of unwinding two Treasury locks and a $5.0 million income tax benefit related to the administrative settlement of various income tax positions.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

The $24.4 million increase in natural gas distribution gross profit primarily reflects rate adjustments and increased throughput as follows:

- $33.4 million net increase in rate adjustments, primarily in the West Texas, Mid-Tex, Louisiana, Kentucky, Tennessee, Virginia and Mississippi service areas.

- $10.6 million increase as a result of an 11 percent increase in consolidated throughput primarily associated with higher residential and commercial consumption and colder weather in most of our service areas.

These increases were partially offset by:

- $7.6 million decrease due to a non-recurring adjustment recorded in the prior-year period to update the estimate for gas delivered to customers but not yet billed to reflect base rate changes.
- $7.0 million decrease related to a prior-year reversal of an accrual for estimated unrecoverable gas costs that did not recur in the current year.
- $1.6 million decrease in revenue-related taxes, primarily due to a decrease in revenues on which the tax is calculated.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income and asset impairments decreased $7.8 million, primarily due to the following:

- $5.4 million decrease due to a state sales tax reimbursement received in March 2010.
- $4.6 million decrease due to the absence of an impairment charge for available-for-sale securities recorded in the prior year.
- $4.5 million decrease in contract labor expenses.
- $4.6 million decrease in travel, legal and other administrative costs.

These decreases were partially offset by:

- $7.5 million increase in employee-related expenses.
- $4.5 million increase in taxes, other than income.

Miscellaneous income decreased $4.4 million due to lower interest income. Interest charges decreased $5.5 million primarily due to lower short-term debt balances and interest rates.

Additionally, results for the fiscal year ended September 30, 2009, were favorably impacted by a one-time tax benefit of $10.5 million. During the second quarter of fiscal 2009, the Company completed a study of the calculations used to estimate its deferred tax rate, and concluded that revisions to these calculations to include more specific jurisdictional tax rates would result in a more accurate calculation of the tax rate at which deferred taxes would reverse in the future. Accordingly, the Company modified the tax rate used to calculate deferred taxes from 38 percent to an individual rate for each legal entity. These rates vary from 36-41 percent depending on the jurisdiction of the legal entity.

Regulated Transmission and Storage Segment

Our regulated transmission and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of excess gas.

Similar to our natural gas distribution segment, our regulated transmission and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our Mid-Tex service area. Natural gas prices do not directly impact the results of this segment as revenues are derived from the transportation of natural gas. However, natural gas prices and demand for natural gas could influence the level of drilling activity in the markets that we serve, which may influence the level of throughput we may be able to transport on our pipeline. Further, natural gas price differences between the various hubs that we serve could influence customers to transport gas through our pipeline to capture arbitrage gains.

The results of Atmos Pipeline — Texas Division are also significantly impacted by the natural gas requirements of the Mid-Tex Division because it is the primary supplier of natural gas for our Mid-Tex Division.

Finally, as a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Review of Financial and Operating Results

Financial and operational highlights for our regulated transmission and storage segment for the fiscal years ended September 30, 2011, 2010, and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
	(In thousands, unless otherwise noted)				
Mid-Tex Division transportation	$125,973	$102,891	$ 89,348	$ 23,082	$ 13,543
Third-party transportation	73,676	73,648	95,314	28	(21,666)
Storage and park and lend services	7,995	10,657	11,858	(2,662)	(1,201)
Other	11,729	15,817	13,138	(4,088)	2,679
Gross profit	219,373	203,013	209,658	16,360	(6,645)
Operating expenses	111,098	105,975	116,495	5,123	(10,520)
Operating income	108,275	97,038	93,163	11,237	3,875
Miscellaneous income	4,715	135	1,433	4,580	(1,298)
Interest charges	31,432	31,174	30,982	258	192
Income before income taxes	81,558	65,999	63,614	15,559	2,385
Income tax expense	29,143	24,513	22,558	4,630	1,955
Net income	$ 52,415	$ 41,486	$ 41,056	$ 10,929	$ 430
Gross pipeline transportation volumes — MMcf	620,904	634,885	706,132	(13,981)	(71,247)
Consolidated pipeline transportation volumes — MMcf	435,012	428,599	528,689	6,413	(100,090)

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

On April 18, 2011, the Railroad Commission of Texas (RRC) issued an order in the rate case of Atmos Pipeline — Texas (APT) that was originally filed in September 2010. The RRC approved an annual operating income increase of $20.4 million as well as the following major provisions that went into effect with bills rendered on and after May 1, 2011:

- Authorized return on equity of 11.8 percent.
- A capital structure of 49.5 percent debt/50.5 percent equity
- Approval of a rate base of $807.7 million, compared to the $417.1 million rate base from the prior rate case.
- An annual adjustment mechanism, which was approved for a three-year pilot program, that will adjust regulated rates up or down by 75 percent of the difference between APT's non-regulated annual revenue and a pre-defined base credit.
- Approval of a straight fixed variable rate design, under which all fixed costs associated with transportation and storage services are recovered through monthly customer charges.

The $16.4 million increase in regulated transmission and storage gross profit was attributable primarily to the following:

- $23.4 million net increase as a result of the rate case that was finalized and became effective in May 2011.
- $3.2 million increase associated with our most recent GRIP filing.

These increases were partially offset by the following:

- $4.8 million decrease due to the absence of the sale of excess gas, which occurred in the prior year.
- $4.4 million decrease due to a decline in throughput to our Mid-Tex Division primarily due to warmer than normal weather during fiscal 2011.

Operating expenses increased $5.1 million primarily due to the following:

- $4.6 million increase due to higher depreciation expense.
- $2.0 million increase due to the absence of a state sales tax reimbursement received in the prior year.

These increases were partially offset by the following:

- $0.8 million decrease related to lower levels of pipeline maintenance activities.
- $0.7 million decrease due to lower employee-related expenses.

Miscellaneous income includes a $6.0 million gain recognized in March 2011 as a result of unwinding two Treasury locks.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

The $6.6 million decrease in regulated transmission and storage gross profit was attributable primarily to the following factors:

- $13.3 million decrease due to lower transportation fees on through-system deliveries due to narrower basis spreads.
- $2.6 million decrease due to decreased through-system volumes primarily associated with market conditions that resulted in reduced wellhead production, decreased drilling activity and increased competition, partially offset by increased deliveries to our Mid-Tex Division.
- $1.6 million net decrease in market-based demand fees, priority reservation fees and compression activity associated with lower throughput.

These decreases were partially offset by the following:

- $9.3 million increase associated with our GRIP filings.
- $2.0 million increase of excess inventory sales in the current-year period.

Operating expenses decreased $10.5 million primarily due to:

- $11.8 million decrease related to reduced contract labor.
- $2.0 million decrease due to a state sales tax reimbursement received in March 2010.

These decreases were partially offset by a $2.1 million increase in taxes, other than income due to higher ad valorem and payroll taxes.

Miscellaneous income decreased $1.3 million due primarily to a decline in intercompany interest income.

Nonregulated Segment

Our nonregulated activities are conducted through Atmos Energy Holdings, Inc. (AEH), which is a wholly-owned subsidiary of Atmos Energy Corporation and operates primarily in the Midwest and Southeast areas of the United States.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. As a result, AEH's gas delivery and related services margins arise from the types of commercial transactions we have structured with our customers and our ability to identify the lowest cost alternative among the natural gas supplies, transportation and markets to which it has access to serve those customers.

AEH's storage and transportation margins arise from (i) utilizing its proprietary 21-mile pipeline located in New Orleans, Louisiana to aggregate gas supply for our regulated natural gas distribution division in Louisiana, its gas delivery activities and, on a more limited basis, for third parties and (ii) managing proprietary storage in Kentucky and Louisiana to supplement the natural gas needs of our natural gas distribution divisions during peak periods.

AEH also seeks to enhance its gross profit margin by maximizing, through asset optimization activities, the economic value associated with the storage and transportation capacity it owns or controls in our natural gas distribution and by its subsidiaries. We attempt to meet these objectives by engaging in natural gas storage transactions in which we seek to find and profit through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time. This process involves purchasing physical natural gas, storing it in the storage and transportation assets to which AEH has access and selling financial instruments at advantageous prices to lock in a gross profit margin.

AEH continually manages its net physical position to attempt to increase the future economic profit that was created when the original transaction was executed. Therefore, AEH may subsequently change its originally scheduled storage injection and withdrawal plans from one time period to another based on market conditions. If AEH elects to accelerate the withdrawal of physical gas, it will execute new financial instruments to offset the original financial instruments. If AEH elects to defer the withdrawal of gas, it will execute new financial instruments to correspond to the revised withdrawal schedule and allow the original financial instrument to settle as contracted.

We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our natural gas marketing storage activities. These financial instruments are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The hedged natural gas inventory is marked to market at the end of each month based on the Gas Daily index with changes in fair value recognized as unrealized gains and losses in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory and the market (spot) prices used to value our physical storage result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized.

AEH also uses financial instruments to capture additional storage arbitrage opportunities that may arise after the original physical inventory hedge and to attempt to insulate and protect the economic value within its asset optimization activities. Changes in fair value associated with these financial instruments are recognized as a component of unrealized margins until they are settled.

Due to the nature of these operations, natural gas prices and differences in natural gas prices between the various markets that we serve (commonly referred to as basis differentials), have a significant impact on our nonregulated businesses. Within our delivered gas activities, basis differentials impact our ability to create value from identifying the lowest cost alternative among the natural gas supplies, transportation and markets to which we have access. Further, higher natural gas prices may adversely impact our accounts receivable collections, resulting in higher bad debt expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense. Higher gas prices, as well as competitive factors in the industry and general economic conditions may also cause customers to conserve or use alternative energy sources. Within our asset optimization activities, higher gas prices could also lead to increased borrowings under our credit facilities resulting in higher interest expense.

Volatility in natural gas prices also has a significant impact on our nonregulated segment. Increased price volatility often has a significant impact on the spreads between the market (spot) prices and forward natural gas prices, which creates opportunities to earn higher arbitrage spreads within our asset optimization activities. Volatility could also impact the basis differentials we capture in our delivered gas activities. However, increased volatility impacts the amounts of unrealized margins recorded in our gross profit and could cause an increase in the amount of cash required to collateralize our risk management liabilities.

Review of Financial and Operating Results

Financial and operational highlights for our nonregulated segment for the fiscal years ended September 30, 2011, 2010 and 2009 are presented below. Gross profit margin consists primarily of margins earned from the delivery of gas and related services requested by our customers, margins earned from storage and transportation services and margins earned from asset optimization activities, which are derived from the utilization of our proprietary and managed third-party storage and transportation assets to capture favorable arbitrage spreads through natural gas trading activities.

Unrealized margins represent the unrealized gains or losses on our net physical gas position and the related financial instruments used to manage commodity price risk as described above. These margins fluctuate based upon changes in the spreads between the physical and forward natural gas prices. Generally, if the physical/financial spread narrows, we will record unrealized gains or lower unrealized losses. If the physical/financial spread widens, we will record unrealized losses or lower unrealized gains. The magnitude of the unrealized gains and losses is also contingent upon the levels of our net physical position at the end of the reporting period.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
	(In thousands, unless otherwise noted)				
Realized margins					
Gas delivery and related services	$ 58,990	$ 59,523	$ 75,341	$ (533)	$(15,818)
Storage and transportation services	14,570	13,206	12,784	1,364	422
Other	5,265	5,347	9,365	(82)	(4,018)
	78,825	78,076	97,490	749	(19,414)
Asset optimization(1)	(3,424)	43,805	52,507	(47,229)	(8,702)
Total realized margins	75,401	121,881	149,997	(46,480)	(28,116)
Unrealized margins	(10,401)	(7,790)	(35,889)	(2,611)	28,099
Gross profit	65,000	114,091	114,108	(49,091)	(17)
Operating expenses, excluding asset impairment	39,113	44,147	49,046	(5,034)	(4,899)
Asset impairment	30,270	—	181	30,270	(181)
Operating income (loss)	(4,383)	69,944	64,881	(74,327)	5,063
Miscellaneous income	657	3,859	6,399	(3,202)	(2,540)
Interest charges	4,015	10,584	14,350	(6,569)	(3,766)
Income (loss) before income taxes	(7,741)	63,219	56,930	(70,960)	6,289
Income tax expense (benefit)	(209)	24,815	23,815	(25,024)	1,000
Net income (loss)	$ (7,532)	$ 38,404	$ 33,115	$(45,936)	$ 5,289
Gross nonregulated delivered gas sales volumes — MMcf	446,903	420,203	441,081	26,700	(20,878)
Consolidated nonregulated delivered gas sales volumes — MMcf	384,799	353,853	370,569	30,946	(16,716)
Net physical position (Bcf)	21.0	15.7	15.9	5.3	(0.2)

(1) Net of storage fees of $15.2 million, $13.2 million and $10.8 million.

Fiscal year ended September 30, 2011 compared with fiscal year ended September 30, 2010

Realized margins for gas delivery, storage and transportation services and other services were $78.8 million during the year ended September 30, 2011 compared with $78.1 million for the prior-year period. The increase primarily reflects the following:

- $1.4 million increase in margins from storage and transportation services, primarily attributable to new drilling projects in the Barnett Shale area.
- $0.6 million decrease in gas delivery and other services primarily due to lower per-unit margins partially offset by a nine percent increase in consolidated delivered gas sales volumes due to new customers in the power generation market. Per-unit margins were $0.13/Mcf in the current year compared with $0.14/Mcf in the prior year. The year-over-year decrease in per-unit margins reflects the impact of increased competition and lower basis spreads.

The $47.2 million decrease in realized asset optimization margins from the prior year primarily reflects the unfavorable impact of weak natural gas market fundamentals which provided fewer favorable trading opportunities.

Unrealized margins decreased $2.6 million in the current period compared to the prior-year period primarily due to the timing of year-over-year realized margins.

Operating expenses decreased $5.0 million primarily due to lower employee-related expenses and ad valorem taxes.

During fiscal 2011, our nonregulated segment recognized $30.3 million of non-cash asset impairment charges associated with two projects. In March 2011, we recorded a $19.3 million charge to substantially write off our investment in Fort Necessity. This project began in February 2008 when Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. At that time, we evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Additionally, during the third quarter of fiscal 2011, we recorded an $11.0 million non-cash charge to impair certain natural gas gathering assets of Atmos Gathering Company. The charge reflected a reduction in the value of the project due to the current low natural gas price environment and the adverse impact of an ongoing lawsuit associated with the project.

Interest charges decreased $6.6 million primarily due to a decrease in intercompany borrowings.

Asset Optimization Activities

AEH monitors the impact of its asset optimization efforts by estimating the gross profit, before related fees, that it captured through the purchase and sale of physical natural gas and the execution of the associated financial instruments. This economic value, combined with the effect of the future reversal of unrealized gains or losses currently recognized in the income statement and related fees is referred to as the potential gross profit.

We define potential gross profit as the change in AEH's gross profit in future periods if its optimization efforts are executed as planned. This amount does not include other operating expenses and associated income taxes that will be incurred to realize this amount. Therefore, it does not represent an estimated increase in future net income. There is no assurance that the economic value or the potential gross profit will be fully realized in the future.

We consider this measure a non-GAAP financial measure as it is calculated using both forward-looking storage injection/withdrawal and hedge settlement estimates and historical financial information. This measure is presented because we believe it provides a more comprehensive view to investors of our asset optimization efforts and thus a better understanding of these activities than would be presented by GAAP measures alone. Because there is no assurance that the economic value or potential gross profit will be realized in the future, corresponding future GAAP amounts are not available.

The following table presents AEH's economic value and its potential gross profit (loss) at September 30, 2011 and 2010.

	September 30	
	2011	2010
	(In millions, unless otherwise noted)	
Economic value	$ 4.9	$ (7.5)
Associated unrealized losses	14.7	12.8
Subtotal	19.6	5.3
Related fees[1]	(17.7)	(10.6)
Potential gross profit (loss)	$ 1.9	$ (5.3)
Net physical position (Bcf)	21.0	15.7

(1) Related fees represent the contractual costs to acquire the storage capacity utilized in our nonregulated segment's asset optimization operations. The fees primarily consist of demand fees and contractual obligations to sell gas below market index in exchange for the right to manage and optimize third party storage assets for the positions we have entered into as of September 30, 2011 and 2010.

During the 2011 fiscal year, our nonregulated segment's economic value increased from a negative economic value of ($7.5) million, or ($0.48)/Mcf at September 30, 2010 to $4.9 million, or $0.23/Mcf at September 30, 2011.

The increase in economic value was attributable to several factors including an increase in the captured spread value resulting from realizing financial instruments with lower spread values, entering into financial hedges with higher average prices and rolling financial instruments to forward periods to capture incremental value. Additionally, as a result of falling gas prices throughout the year, we injected a net 5.3 Bcf, which reduced the overall weighted average cost of gas held in storage.

The economic value is based upon planned storage injection and withdrawal schedules and its realization is contingent upon the execution of this plan, weather and other execution factors. Since AEH actively manages and optimizes its portfolio to attempt to enhance the future profitability of its storage position, it may change its scheduled storage injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot ensure that the economic value or the potential gross profit as of September 30, 2011 will be fully realized in the future nor can we predict in what time periods such realization may occur. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Fiscal year ended September 30, 2010 compared with fiscal year ended September 30, 2009

Realized margins for gas delivery, storage and transportation services and other services contributed 64 percent to total realized margins during fiscal 2010, with asset optimization activities contributing the remaining 36 percent. In fiscal 2009, gas delivery, storage and transportation services and other services represented 65 percent of the nonregulated segment's realized margins with asset optimization contributing the remaining 35 percent. The $28.1 million decrease in realized gross profit reflected:

- $19.4 million decrease in gas delivery, storage and transportation services and other services as a result of narrowing basis spreads, combined with lower delivered sales volumes. Per-unit delivered gas margins were $0.14/Mcf in fiscal 2010, compared with $0.17/Mcf in fiscal 2009, while delivered gas volumes were 5 percent lower in fiscal 2010 when compared with fiscal 2009.

- $8.7 million decrease in asset optimization due to lower margins earned on storage optimization activities, lower basis gains earned from utilizing leased capacity and lower margins earned on asset management plans, partially offset by higher realized storage and trading gains during fiscal 2010.

The decrease in realized gross profit was offset by a $28.1 million increase in unrealized margins due to the period-over-period timing of storage withdrawal gains and the associated reversal of unrealized gains into realized gains.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense, taxes, other than income taxes, and asset impairments decreased $5.1 million primarily due a decrease in employee and other administrative costs, partially offset by an increase in gas gathering activities.

LIQUIDITY AND CAPITAL RESOURCES

The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a variety of sources, including internally generated funds and borrowings under our commercial paper program and bank credit facilities. Additionally, we have various uncommitted trade credit lines with our gas suppliers that we utilize to purchase natural gas on a monthly basis. Finally, from time to time, we raise funds from the public debt and equity capital markets to fund our liquidity needs.

We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. We also evaluate the levels of committed borrowing capacity that we require. During fiscal 2011, we executed on our strategy of consolidating our short-term facilities used for our regulated operations into a single line of credit, including the following:

- On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.
- In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased during fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.
- In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

As a result of these changes, we now have $985 million of availability from our commercial paper program and four committed revolving credit facilities with third parties.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011 using commercial paper borrowings. In effect, we refinanced this debt on a long-term basis through the issuance of $400 million 5.50% 30-year unsecured senior notes on June 10, 2011. On September 30, 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost of financing the anticipated issuances of senior notes. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury lock and settlement. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks. Substantially all of the net proceeds of approximately $394 million were used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Additionally, we had planned to issue $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges. Due primarily to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound. A pretax cash gain of approximately $28 million was recorded in March 2011.

Finally, we intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of $350 million 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

We believe the liquidity provided by our senior notes and committed credit facilities, combined with our operating cash flows, will be sufficient to fund our working capital needs and capital expenditure program for fiscal year 2012.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating, investing and financing activities for the years ended September 30, 2011, 2010 and 2009 are presented below.

	For the Fiscal Year Ended September 30				
	2011	2010	2009	2011 vs. 2010	2010 vs. 2009
	(In thousands)				
Total cash provided by (used in)					
Operating activities	$ 582,844	$ 726,476	$ 919,233	$(143,632)	$(192,757)
Investing activities	(627,386)	(542,702)	(517,201)	(84,684)	(25,501)
Financing activities	44,009	(163,025)	(337,546)	207,034	174,521
Change in cash and cash equivalents	(533)	20,749	64,486	(21,282)	(43,737)
Cash and cash equivalents at beginning of period	131,952	111,203	46,717	20,749	64,486
Cash and cash equivalents at end of period	$ 131,419	$ 131,952	$ 111,203	$ (533)	$ 20,749

Cash flows from operating activities

Year-over-year changes in our operating cash flows primarily are attributable to changes in net income, working capital changes, particularly within our natural gas distribution segment resulting from the price of natural gas and the timing of customer collections, payments for natural gas purchases and purchased gas cost recoveries. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

Fiscal Year ended September 30, 2011 compared with fiscal year ended September 30, 2010

For the fiscal year ended September 30, 2011, we generated operating cash flow of $582.8 million from operating activities compared with $726.5 million in the prior year. The year-over-year decrease reflects the absence of an $85 million income tax refund received in the prior year coupled with the timing of gas cost recoveries under our purchased gas cost mechanisms and other net working capital changes.

Fiscal Year ended September 30, 2010 compared with fiscal year ended September 30, 2009

For the fiscal year ended September 30, 2010, we generated operating cash flow of $726.5 million from operating activities compared with $919.2 million in fiscal 2009, primarily due to the fluctuation in gas costs. Gas costs, which reached historically high levels during the 2008 injection season, declined sharply when the economy slipped into the recession and have remained relatively stable since that time. Operating cash flows for the fiscal 2010 period reflect the recovery of lower gas costs through purchased gas recovery mechanisms and sales. This is in contrast to the fiscal 2009 period, where operating cash flows were favorably influenced by the recovery of high gas costs during a period of falling prices.

Cash flows from investing activities

In recent fiscal years, a substantial portion of our cash resources has been used to fund our ongoing construction program and improvements to information technology systems. Our ongoing construction program enables us to provide safe and reliable natural gas distribution services to our existing customer base, expand our natural gas distribution services into new markets, enhance the integrity of our pipelines and, more recently, expand our intrastate pipeline network. In executing our current rate strategy, we are focusing our capital spending in jurisdictions that permit us to earn an adequate return timely on our investment without compromising the safety or reliability of our system. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas natural gas distribution divisions and our Atmos Pipeline — Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

In early fiscal 2010, two coalitions of cities, representing the majority of the cities our Mid-Tex Division serves, agreed to a program of installing, beginning in the first quarter of fiscal 2011, 100,000 steel service line replacements during fiscal 2011 and 2012, with approved recovery of the associated return, depreciation and taxes. During fiscal 2011, we replaced 35,852 lines for a cost of $49.7 million. The program is progressing on schedule for completion in September 2012. As a result of this project and spending to replace our regulated customer service systems and our nonregulated energy trading risk management system, we anticipate capital expenditures will remain elevated during the next fiscal year.

For the fiscal year ended September 30, 2011, we incurred $623.0 million for capital expenditures compared with $542.6 million for the fiscal year ended September 30, 2010 and $509.5 million for the fiscal year ended September 30, 2009.

The $80.4 million increase in capital expenditures in fiscal 2011 compared to fiscal 2010 primarily reflects spending for the steel service line replacement program in the Mid-Tex Division, the development of new customer billing and information systems for our natural gas distribution and our nonregulated segments and the construction of a new customer contact center in Amarillo, Texas, partially offset by costs incurred in the prior fiscal year to relocate the company's information technology data center.

The $33.1 million increase in capital expenditures in fiscal 2010 compared to fiscal 2009 primarily reflects spending for the relocation of our information technology data center to a new facility, the construction of two service centers and the steel service line replacement program in our Mid-Tex Division.

Cash flows from financing activities

For the fiscal year ended September 30, 2011, our financing activities generated $44.0 million in cash, while financing activities for the fiscal year ended September 30, 2010 used $163.0 million in cash compared with cash of $337.5 million used for the fiscal year ended September 30, 2009. Our significant financing activities for the fiscal years ended September 30, 2011, 2010 and 2009 are summarized as follows:

2011

During the fiscal year ended September 30, 2011, we:

- Received $394.5 million net cash proceeds in June 2011 related to the issuance of $400 million 5.50% senior notes due 2041.
- Borrowed a net $83.3 million under our short-term facilities to fund working capital needs.
- Received $27.8 million cash in March 2011 related to the unwinding of two Treasury locks.
- Received $20.1 million cash in June 2011 related to the settlement of three Treasury locks associated with the $400 million 5.50% senior notes offering.
- Received $7.8 million net proceeds related to the issuance of 0.3 million shares of common stock.

- Paid $360.1 million for scheduled long-term debt repayments, including our $350 million 7.375% senior notes that were paid on their maturity date on May 15, 2011.
- Paid $124.0 million in cash dividends which reflected a payout ratio of 60 percent of net income.
- Paid $5.3 million for the repurchase of equity awards.

2010

During the fiscal year ended September 30, 2010, we:

- Paid $124.3 million in cash dividends which reflected a payout ratio of 61 percent of net income.
- Paid $100.5 million for the repurchase of common stock under an accelerated share repurchase agreement.
- Borrowed a net $54.3 million under our short-term facilities due to the impact of seasonal natural gas purchases.
- Received $8.8 million net proceeds related to the issuance of 0.4 million shares of common stock, which is a 68 percent decrease compared to the prior year due primarily to the fact that beginning in fiscal 2010 shares were purchased on the open market rather than being issued by us to the Direct Stock Purchase Plan and the Retirement Savings Plan.
- Paid $1.2 million to repurchase equity awards.

2009

During the fiscal year ended September 30, 2009, we:

- Paid $407.4 million to repay our $400 million 4.00% unsecured notes.
- Repaid a net $284.0 million short-term borrowings under our credit facilities.
- Paid $121.5 million in cash dividends which reflected a payout ratio of 64 percent of net income.
- Received $445.6 million in net proceeds related to the March 2009 issuance of $450 million of 8.50% Senior Notes due 2019. The net proceeds were used to repay the $400 million 4.00% unsecured notes.
- Received $27.7 million net proceeds related to the issuance of 1.2 million shares of common stock.
- Received $1.9 million net proceeds related to the settlement of the Treasury lock agreement associated with the March 2009 issuance of the $450 million of 8.50% Senior Notes due 2019.

The following table shows the number of shares issued for the fiscal years ended September 30, 2011, 2010 and 2009:

	For the Fiscal Year Ended September 30		
	2011	2010	2009
Shares issued:			
Direct stock purchase plan	—	103,529	407,262
Retirement savings plan	—	79,722	640,639
1998 Long-term incentive plan	675,255	421,706	686,046
Outside directors stock-for-fee plan	2,385	3,382	3,079
Total shares issued	677,640	608,339	1,737,026

The number of shares issued in fiscal 2011 compared with the number of shares issued in fiscal 2010 primarily reflects an increased number of shares issued under our 1998 Long-Term Incentive Plan due to the exercise of stock options during the current fiscal year. This increase was partially offset by the fact that we are purchasing shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. During fiscal 2011, we cancelled and retired 169,793 shares attributable to federal withholdings on equity awards and repurchased and retired 375,468 shares attributable to our 2010 accelerated share repurchase agreement described below, which are not included in the table above.

The year-over-year decrease in the number of shares issued in fiscal 2010 compared with the number of shares issued in fiscal 2009, primarily reflects the fact that in fiscal 2010, we began to purchase shares in the open market rather than issuing new shares for the Direct Stock Purchase Plan and the Retirement Savings Plan. Further, a higher average stock price during the second and third quarters of fiscal 2010 compared to the second and third quarters of 2009 enabled us to issue fewer shares during fiscal 2010. Additionally, during fiscal 2010, we cancelled and retired 37,365 shares attributable to federal withholdings on equity awards and repurchased and retired 2,958,580 common shares as part of our 2010 accelerated share repurchase agreement described below, which are not included in the table above.

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans.

We paid $100 million to Goldman Sachs & Co. on July 7, 2010 for shares of Atmos Energy common stock in a share forward transaction and received 2,958,580 shares. On March 4, 2011, we received and retired an additional 375,468 common shares, which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the effective share repurchase price of our common stock over the duration of the agreement, which was $29.99. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Share Repurchase Program

On September 28, 2011 the Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company.

Credit Facilities

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply to meet our customers' needs could significantly affect our borrowing requirements. However, our short-term borrowings typically reach their highest levels in the winter months.

As of September 30, 2011, we financed our short-term borrowing requirements through a combination of a $750.0 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided $985 million of working capital funding. As of September 30, 2011, the amount available to us under our credit facilities, net of outstanding letters of credit, was $702.5 million. These facilities are described in further detail in Note 7 to the consolidated financial statements.

On May 2, 2011, we replaced our five-year $566.7 million unsecured credit facility, due to expire in December 2011, with a five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion.

In December 2010, we replaced AEM's $450 million 364-day facility with a $200 million, three-year facility. The reduced amount of the new facility is due to the current low cost of gas and AEM's ability to access an intercompany facility that was increased in fiscal 2011; however, this facility contains an accordion feature that could increase our borrowing capacity to $500 million.

In October 2010, we replaced our $200 million 364-day revolving credit agreement with a $200 million 180-day revolving credit agreement that expired in April 2011. As planned, we did not replace or extend this agreement.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities. At September 30, 2011, $900 million was available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our regulated and nonregulated businesses and the regulatory environment in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Service (Moody's) and Fitch Ratings, Ltd. (Fitch). On May 11, 2011, Moody's upgraded our senior unsecured debt rating to Baa1 from Baa2, with a ratings outlook of stable, citing steady rate increases, improving credit metrics and a strategic focus on lower risk regulated activities as reasons for the upgrade. On June 2, 2011, Fitch upgraded our senior unsecured debt rating to A- from BBB+, with a ratings outlook of stable, citing a constructive regulatory environment, strategic focus on lower risk regulated activities and the geographic diversity of our regulated operations as key rating factors. As of September 30, 2011, S&P maintained a stable outlook. Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Unsecured senior long-term debt	BBB+	Baa1	A-
Commercial paper	A-2	P-2	F-2

A significant degradation in our operating performance or a significant reduction in our liquidity caused by more limited access to the private and public credit markets as a result of deteriorating global or national financial and credit conditions could trigger a negative change in our ratings outlook or even a reduction in our credit ratings by the three credit rating agencies. This would mean more limited access to the private and public credit markets and an increase in the costs of such borrowings.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating is AAA for S&P, Aaa for Moody's and AAA for Fitch. The lowest investment grade credit rating is BBB- for S&P, Baa3 for Moody's and BBB- for Fitch. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independently of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of September 30, 2011. Our debt covenants are described in Note 7 to the consolidated financial statements.

Capitalization

The following table presents our capitalization as of September 30, 2011 and 2010:

	September 30			
	2011		2010	
	(In thousands, except percentages)			
Short-term debt	$ 206,396	4.4%	$ 126,100	2.8%
Long-term debt	2,208,551	47.3%	2,169,682	48.5%
Shareholders' equity	2,255,421	48.3%	2,178,348	48.7%
Total capitalization, including short-term debt	$4,670,368	100.0%	$4,474,130	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 51.7 percent and 51.3 percent at September 30, 2011 and 2010. The increase in the debt to capitalization ratio primarily reflects an increase in short-term debt as of September 30, 2011 compared to the prior year. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. We intend to continue to maintain our debt to capitalization ratio in a target range of 50 to 55 percent.

Contractual Obligations and Commercial Commitments

The following table provides information about contractual obligations and commercial commitments at September 30, 2011.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(In thousands)		
Contractual Obligations					
Long-term debt[1]	$2,212,565	$ 2,434	$250,131	$500,000	$1,460,000
Short-term debt[1]	206,396	206,396	—	—	—
Interest charges[2]	1,574,702	136,452	250,841	198,596	988,813
Gas purchase commitments[3]	460,179	274,985	185,194	—	—
Capital lease obligations[4]	1,194	186	372	372	264
Operating leases[4]	199,567	17,718	33,365	30,376	118,108
Demand fees for contracted storage[5]	19,339	11,421	6,770	983	165
Demand fees for contracted transportation[6]	37,295	13,941	19,929	3,425	—
Financial instrument obligations[7]	93,542	15,453	78,089	—	—
Postretirement benefit plan contributions[8]	194,323	31,519	28,543	35,122	99,139
Total contractual obligations	$4,999,102	$710,505	$853,234	$768,874	$2,666,489

(1) See Note 7 to the consolidated financial statements.

(2) Interest charges were calculated using the stated rate for each debt issuance.

(3) Gas purchase commitments were determined based upon contractually determined volumes at prices estimated based upon the index specified in the contract, adjusted for estimated basis differentials and contractual discounts as of September 30, 2011.

(4) See Note 14 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our nonregulated segment. Contractual demand fees for contracted storage for our natural gas distribution segment are excluded as these costs are fully recoverable through our purchase gas adjustment mechanisms.

(6) Represents third party contractual demand fees for transportation in our nonregulated segment.

(7) Represents liabilities for natural gas commodity financial instruments that were valued as of September 30, 2011. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the financial instruments are settled. The table above excludes $1.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations.

(8) Represents expected contributions to our postretirement benefit plans.

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2011, AEH was committed to purchase 103.3 Bcf within one year, 46.4 Bcf within one to three years and 0.9 Bcf after three years under indexed contracts. AEH is committed to purchase 4.2 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $3.49 to $6.36 per Mcf.

With the exception of our Mid-Tex Division, our natural gas distribution segment maintains supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of natural gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under these contract terms as of September 30, 2011 are reflected in the table above.

Risk Management Activities

We use financial instruments to mitigate commodity price risk and, periodically, to manage interest rate risk. We conduct risk management activities through our natural gas distribution and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our nonregulated segments, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the financial instruments being treated as mark to market instruments through earnings.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated segment associated with deliveries under fixed-priced forward contracts to deliver gas to customers, and we use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in our nonregulated segment, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

We record our financial instruments as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. Substantially all of our financial instruments are valued using external market quotes and indices.

The following table shows the components of the change in fair value of our natural gas distribution segment's financial instruments for the fiscal year ended September 30, 2011 (in thousands):

Fair value of contracts at September 30, 2010	$(49,600)
Contracts realized/settled	(51,136)
Fair value of new contracts	2,584
Other changes in value	18,875
Fair value of contracts at September 30, 2011	$(79,277)

The fair value of our natural gas distribution segment's financial instruments at September 30, 2011, is presented below by time period and fair value source:

	Fair Value of Contracts at September 30, 2011				
	Maturity in years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(12,413)	$(66,864)	$—	$—	$(79,277)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(12,413)	$(66,864)	$—	$—	$(79,277)

The tables above include $1.3 million of current liabilities from risk management activities that are classified as liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations.

The following table shows the components of the change in fair value of our nonregulated segment's financial instruments for the fiscal year ended September 30, 2011 (in thousands):

Fair value of contracts at September 30, 2010	$(12,374)
Contracts realized/settled	4,017
Fair value of new contracts	—
Other changes in value	(16,693)
Fair value of contracts at September 30, 2011	(25,050)
Netting of cash collateral	28,787
Cash collateral and fair value of contracts at September 30, 2011	$ 3,737

The fair value of our nonregulated segment's financial instruments at September 30, 2011, is presented below by time period and fair value source.

	Fair Value of Contracts at September 30, 2011				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(14,823)	$(10,050)	$(177)	$—	$(25,050)
Prices based on models and other valuation methods	—	—	—	—	—
Total Fair Value	$(14,823)	$(10,050)	$(177)	$—	$(25,050)

Employee Benefit Programs

An important element of our total compensation program, and a significant component of our operation and maintenance expense, is the offering of various benefit programs to our employees. These programs include medical and dental insurance coverage and pension and postretirement programs.

Medical and Dental Insurance

We offer medical and dental insurance programs to substantially all of our employees, and we believe these programs are consistent with other programs in our industry. Since 2005, we have experienced medical and prescription inflation of approximately seven percent. In recent years, we have strived to actively manage our health care costs through the introduction of a wellness strategy that is focused on helping employees to identify health risks and to manage these risks through improved lifestyle choices.

In March 2010, President Obama signed *The Patient Protection and Affordable Care Act* into law (the "Health Care Reform Act"). The Health Care Reform Act will be phased in over an eight-year period. Although we are still assessing the impact of the Health Care Reform Act on the health care benefits we provide to our employees, the design of our health care plans has already changed in order to comply with provisions of the Health Care Reform Act that have already gone into effect or will be going into effect in fiscal 2012. For example, lifetime maximums on benefits have been eliminated, coverage for dependent children has been extended to age 26 and all costs of preventive coverage must be paid for by the insurer. In 2014, health insurance exchanges will open in each state in order to provide a competitive marketplace for purchasing health insurance by individuals. Companies who offer health insurance to their employees could face a substantial increase in premiums at that time if they choose to continue to provide such coverage. However, companies who elect to cease providing health insurance to their employees will be faced with paying significant penalties to the federal government for each employee who receives coverage through an exchange. We will continue to monitor all developments on health care reform and continue to comply with all existing relevant laws and regulations.

For fiscal 2012, we anticipate an approximate 10 percent medical and prescription drug inflation rate, primarily due to anticipated higher claims costs and the implementation of the Health Care Reform Act.

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2011, our total net periodic pension and other benefits costs was $56.6 million, compared with $50.8 million and $50.2 million for the fiscal years ended September 30, 2010 and 2009. These costs relating to our natural gas distribution operations are recoverable through our gas distribution rates. A portion of these costs is capitalized into our gas distribution rate base, and the remaining costs are recorded as a component of operation and maintenance expense.

Our fiscal 2011 costs were determined using a September 30, 2010 measurement date. As of September 30, 2010, interest and corporate bond rates utilized to determine our discount rates were significantly higher than the interest and corporate bond rates as of September 30, 2009, the measurement date for our fiscal 2010 net periodic cost. Accordingly, we decreased our discount rate used to determine our fiscal 2011 pension and benefit costs to 5.39 percent. Our expected return on our pension plan assets remained constant at 8.25 percent. Accordingly, our fiscal 2011 pension and postretirement medical costs were higher than in the prior year.

The increase in total net periodic pension and other benefits costs during fiscal 2010 compared with fiscal 2009 primarily reflects the decline in fair value of our plan assets. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. At our September 30, 2009 measurement date, the interest rates were slightly lower than the interest rates at September 30, 2008, the measurement date used to determine our fiscal 2009 net periodic cost. Our expected return on our pension plan assets remained constant at 8.25 percent.

Pension and Postretirement Plan Funding

Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

In accordance with the Pension Protection Act of 2006 (PPA), we determined the funded status of our plans as of January 1, 2011. Based on this valuation, we were required to contribute cash of $0.9 million to our pension plans during fiscal 2011. The need for this funding reflects the decline in the fair value of the plans' assets resulting from the unfavorable market conditions experienced during 2008 and 2009. This contribution will increase the level of our plan assets to achieve a desirable PPA funding threshold.

During fiscal 2010, we did not contribute cash to our pension plans as the fair value of the plans' assets recovered somewhat during the year from the unfavorable market conditions experienced in the latter half of calendar year 2008 and our plan assets were sufficient to achieve a desirable funding threshold as established by the PPA. During fiscal 2009, we contributed $21.0 million to our pension plans to achieve the same desired level of funding as established by the PPA.

We contributed $11.3 million, $11.8 million and $10.1 million to our postretirement benefits plans for the fiscal years ended September 30, 2011, 2010 and 2009. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

Outlook for Fiscal 2012 and Beyond

As of September 30, 2011, interest and corporate bond rates utilized to determine our discount rates, which impacted our fiscal 2012 net periodic pension and postretirement costs, were lower than the interest and corporate bond rates as of September 30, 2010, the measurement date for our fiscal 2011 net periodic cost. As a result of the lower interest and corporate bond rates, we decreased the discount rate used to determine our fiscal 2012 pension and benefit costs to 5.05 percent. We reduced the expected return on our pension plan assets to 7.75 percent, based on historical experience and the current market projection of the target asset allocation. Although the fair value of our plan assets has declined as the financial markets have declined, the impact of this decline is partially mitigated by the fact that assets are smoothed for purposes of determining net periodic pension cost which results in asset gains and losses that are recognized over time as a component of net periodic pension and benefit costs for our Pension Account Plan, our largest funded plan. Due to the decrease in our discount rate and our expected return on plan assets as well as the decline in the fair value of our plan assets, we expect our fiscal 2012 pension and postretirement medical costs to increase compared to fiscal 2011.

Based upon market conditions subsequent to September 30, 2011 the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $25 million and $30 million to the Plans in fiscal 2012. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds. With respect to our postretirement medical plans, we anticipate contributing approximately $32 million during fiscal 2012.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the Plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts are impacted by actual investment returns, changes in interest rates and changes in the demographic composition of the participants in the plan.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan with enhanced features, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits.

RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the consolidated financial statements.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest-rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business activities.

We conduct risk management activities through both our natural gas distribution and nonregulated segments. In our natural gas distribution segment, we use a combination of physical storage, fixed physical contracts and fixed financial contracts to protect us and our customers against unusually large winter period gas price increases. In our nonregulated segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial instruments including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our risk management activities and related accounting treatment are described in further detail in Note 4 to the consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper and our other short-term borrowings.

Commodity Price Risk

Natural gas distribution segment

We purchase natural gas for our natural gas distribution operations. Substantially all of the costs of gas purchased for natural gas distribution operations are recovered from our customers through purchased gas cost adjustment mechanisms. Therefore, our natural gas distribution operations have limited commodity price risk exposure.

Nonregulated segment

Our nonregulated segment is also exposed to risks associated with changes in the market price of natural gas. For our nonregulated segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a $0.50 change in the forward NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH's net open position (including existing storage and related financial contracts) at September 30, 2011 of 0.1 Bcf, a $0.50 change in the forward NYMEX price would have had a $0.1 million impact on our consolidated net income.

Changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; but, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our net physical position at September 30, 2011 and assuming our hedges would still qualify as highly effective, a $0.50 change in the difference between the Gas Daily and NYMEX indices would impact our reported net income by approximately $6.7 million.

Additionally, these changes could cause us to recognize a risk management liability, which would require us to place cash into an escrow account to collateralize this liability position. This, in turn, would reduce the amount of cash we would have on hand to fund our working capital needs.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately $1.2 million during 2011.

ITEM 8. ***Financial Statements and Supplementary Data.***

Index to financial statements and financial statement schedule:

All other financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and accompanying notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2011 and 2010, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2011. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atmos Energy Corporation's internal control over financial reporting as of September 30, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 22, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 22, 2011

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30	
	2011	2010
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$6,607,552	$6,384,396
Construction in progress	209,242	157,922
	6,816,794	6,542,318
Less accumulated depreciation and amortization	1,668,876	1,749,243
Net property, plant and equipment	5,147,918	4,793,075
Current assets		
Cash and cash equivalents	131,419	131,952
Accounts receivable, less allowance for doubtful accounts of $7,440 in 2011 and $12,701 in 2010	273,303	273,207
Gas stored underground	289,760	319,038
Other current assets	316,471	150,995
Total current assets	1,010,953	875,192
Goodwill and intangible assets	740,207	740,148
Deferred charges and other assets	383,793	355,376
	$7,282,871	$6,763,791
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2011 — 90,296,482 shares, 2010 — 90,164,103 shares	$ 451	$ 451
Additional paid-in capital	1,732,935	1,714,364
Accumulated other comprehensive loss	(48,460)	(23,372)
Retained earnings	570,495	486,905
Shareholders' equity	2,255,421	2,178,348
Long-term debt	2,206,117	1,809,551
Total capitalization	4,461,538	3,987,899
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	291,205	266,208
Other current liabilities	367,563	413,640
Short-term debt	206,396	126,100
Current maturities of long-term debt	2,434	360,131
Total current liabilities	867,598	1,166,079
Deferred income taxes	960,093	829,128
Regulatory cost of removal obligation	428,947	350,521
Deferred credits and other liabilities	564,695	430,164
	$7,282,871	$6,763,791

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Operating revenues			
Natural gas distribution segment	$2,531,863	$2,842,638	$2,884,796
Regulated transmission and storage segment	219,373	203,013	209,658
Nonregulated segment	2,024,893	2,146,658	2,283,988
Intersegment eliminations	(428,495)	(472,474)	(509,331)
	4,347,634	4,719,835	4,869,111
Purchased gas cost			
Natural gas distribution segment	1,487,499	1,820,627	1,887,192
Regulated transmission and storage segment	—	—	—
Nonregulated segment	1,959,893	2,032,567	2,169,880
Intersegment eliminations	(426,999)	(470,864)	(507,639)
	3,020,393	3,382,330	3,549,433
Gross profit	1,327,241	1,337,505	1,319,678
Operating expenses			
Operation and maintenance	449,290	460,513	485,704
Depreciation and amortization	227,099	211,589	211,984
Taxes, other than income	178,683	188,252	180,242
Asset impairments	30,270	—	5,382
Total operating expenses	885,342	860,354	883,312
Operating income	441,899	477,151	436,366
Miscellaneous income (expense), net	21,499	(156)	(3,067)
Interest charges	150,825	154,360	152,638
Income from continuing operations before income taxes	312,573	322,635	280,661
Income tax expense	113,689	124,362	97,362
Income from continuing operations	198,884	198,273	183,299
Income from discontinued operations, net of tax ($5,502, $4,425 and $2,929)	8,717	7,566	7,679
Net income	$ 207,601	$ 205,839	$ 190,978
Basic earnings per share			
Income per share from continuing operations	$ 2.18	$ 2.14	$ 1.99
Income per share from discontinued operations	0.10	0.08	0.09
Net income per share — basic	$ 2.28	$ 2.22	$ 2.08
Diluted earnings per share			
Income per share from continuing operations	$ 2.17	$ 2.12	$ 1.98
Income per share from discontinued operations	0.10	0.08	0.09
Net income per share — diluted	$ 2.27	$ 2.20	$ 2.07
Weighted average shares outstanding:			
Basic	90,201	91,852	91,117
Diluted	90,652	92,422	91,620

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common stock		Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Number of Shares	Stated Value				
	(In thousands, except share and per share data)					
Balance, September 30, 2008	90,814,683	$454	$1,744,384	$(35,947)	$ 343,601	$2,052,492
Comprehensive income:						
Net income	—	—	—	—	190,978	190,978
Unrealized holding losses on investments, net	—	—	—	(1,820)	—	(1,820)
Other than temporary impairment of investments, net	—	—	—	3,370	—	3,370
Treasury lock agreements, net	—	—	—	3,606	—	3,606
Cash flow hedges, net	—	—	—	10,607	—	10,607
Total comprehensive income						206,741
Change in measurement date for employee benefit plans	—	—	—	—	(7,766)	(7,766)
Cash dividends ($1.32 per share)	—	—	—	—	(121,460)	(121,460)
Common stock issued:						
Direct stock purchase plan	407,262	2	8,743	—	—	8,745
Retirement savings plan	640,639	3	16,571	—	—	16,574
1998 Long-term incentive plan	686,046	4	8,075	—	—	8,079
Employee stock-based compensation	—	—	13,280	—	—	13,280
Outside directors stock-for-fee plan	3,079	—	76	—	—	76
Balance, September 30, 2009	92,551,709	463	1,791,129	(20,184)	405,353	2,176,761
Comprehensive income:						
Net income	—	—	—	—	205,839	205,839
Unrealized holding gains on investments, net	—	—	—	1,745	—	1,745
Treasury lock agreements, net	—	—	—	2,030	—	2,030
Cash flow hedges, net	—	—	—	(6,963)	—	(6,963)
Total comprehensive income						202,651
Repurchase of common stock	(2,958,580)	(15)	(100,435)	—	—	(100,450)
Repurchase of equity awards	(37,365)	—	(1,191)	—	—	(1,191)
Cash dividends ($1.34 per share)	—	—	—	—	(124,287)	(124,287)
Common stock issued:						
Direct stock purchase plan	103,529	1	2,881	—	—	2,882
Retirement savings plan	79,722	—	2,281	—	—	2,281
1998 Long-term incentive plan	421,706	2	8,708	—	—	8,710
Employee stock-based compensation	—	—	10,894	—	—	10,894
Outside directors stock-for-fee plan	3,382	—	97	—	—	97
Balance, September 30, 2010	90,164,103	451	1,714,364	(23,372)	486,905	2,178,348
Comprehensive income:						
Net income	—	—	—	—	207,601	207,601
Unrealized holding losses on investments, net	—	—	—	(1,647)	—	(1,647)
Treasury lock agreements, net	—	—	—	(28,689)	—	(28,689)
Cash flow hedges, net	—	—	—	5,248	—	5,248
Total comprehensive income						182,513
Repurchase of common stock	(375,468)	(2)	2	—	—	—
Repurchase of equity awards	(169,793)	(1)	(5,298)	—	—	(5,299)
Cash dividends ($1.36 per share)	—	—	—	—	(124,011)	(124,011)
Common stock issued:						
Direct stock purchase plan	—	—	(54)	—	—	(54)
1998 Long-term incentive plan	675,255	3	13,886	—	—	13,889
Employee stock-based compensation	—	—	9,958	—	—	9,958
Outside directors stock-for-fee plan	2,385	—	77	—	—	77
Balance, September 30, 2011	90,296,482	$451	$1,732,935	$(48,460)	$ 570,495	$2,255,421

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2011	2010	2009
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 207,601	$ 205,839	$ 190,978
Adjustments to reconcile net income to net cash provided by operating activities:			
Asset impairments	30,270	—	5,382
Depreciation and amortization:			
Charged to depreciation and amortization	233,155	216,960	217,208
Charged to other accounts	228	173	94
Deferred income taxes	117,353	196,731	129,759
Stock-based compensation	11,586	12,655	14,494
Debt financing costs	9,438	11,908	10,364
Other	(961)	(1,245)	(1,177)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(96)	(40,401)	244,713
Decrease in gas stored underground	27,737	54,014	194,287
(Increase) decrease in other current assets	(38,048)	(18,387)	117,737
(Increase) decrease in deferred charges and other assets	(53,519)	14,886	(106,231)
Increase (decrease) in accounts payable and accrued liabilities	23,904	58,069	(181,978)
Decrease in other current liabilities	(57,495)	(48,992)	(717)
Increase in deferred credits and other liabilities	71,691	64,266	84,320
Net cash provided by operating activities	582,844	726,476	919,233
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(622,965)	(542,636)	(509,494)
Other, net	(4,421)	(66)	(7,707)
Net cash used in investing activities	(627,386)	(542,702)	(517,201)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	83,306	54,268	(283,981)
Net proceeds from issuance of long-term debt	394,466	—	445,623
Settlement of Treasury lock agreements	20,079	—	1,938
Unwinding of Treasury lock agreements	27,803	—	—
Repayment of long-term debt	(360,131)	(131)	(407,353)
Cash dividends paid	(124,011)	(124,287)	(121,460)
Repurchase of common stock	—	(100,450)	—
Repurchase of equity awards	(5,299)	(1,191)	—
Issuance of common stock	7,796	8,766	27,687
Net cash provided by (used in) financing activities	44,009	(163,025)	(337,546)
Net increase (decrease) in cash and cash equivalents	(533)	20,749	64,486
Cash and cash equivalents at beginning of year	131,952	111,203	46,717
Cash and cash equivalents at end of year	$ 131,419	$ 131,952	$ 111,203

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Atmos Energy Corporation ("Atmos Energy" or the "Company") and our subsidiaries are engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as certain other nonregulated businesses. Through our natural gas distribution business, we deliver natural gas through sales and transportation arrangements to over three million residential, commercial, public-authority and industrial customers through our six regulated natural gas distribution divisions in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri[1]
Atmos Energy Kentucky/Mid-States Division	Georgia[1], Illinois[1], Iowa[1], Kentucky, Missouri[1], Tennessee, Virginia[1]
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

(1) Denotes locations where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our natural gas distribution business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which our natural gas distribution divisions operate. Our corporate headquarters and shared-services function are located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

In May 2011, we announced that we had entered into a definitive agreement to sell our natural gas distribution operations in Missouri, Illinois and Iowa, representing approximately 84,000 customers. The results of these operations have been separately reported as discontinued operations.

Our regulated transmission and storage business consists of the regulated operations of our Atmos Pipeline — Texas Division, a division of the Company. This division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary to the pipeline industry including parking arrangements, lending and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline. Lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands.

Our nonregulated businesses operate primarily in the Midwest and Southeast through various wholly-owned subsidiaries of Atmos Energy Holdings, Inc., (AEH). AEH is wholly owned by the Company and based in Houston, Texas. Through AEH, we provide natural gas management and transportation services to municipalities, natural gas distribution companies, including certain divisions of Atmos Energy and third parties.

AEH's primary business is to deliver gas and provide related services by aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering gas to customers at competitive prices. In addition, AEH utilizes proprietary and customer-owned transportation and storage assets to provide various delivered gas services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of financial instruments. AEH also seeks to maximize, through asset optimization activities, the economic value associated with storage and transportation capacity it owns or controls. Certain of these arrangements are with regulated affiliates of the Company, which have been approved by applicable state regulatory commissions.

2. Summary of Significant Accounting Policies

Principles of consolidation — The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process.

Basis of comparison — Certain prior-year amounts have been reclassified to conform with the current year presentation.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligations, impairment of long-lived assets, risk management and trading activities, fair value measurements and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results could differ from those estimates.

Regulation — Our natural gas distribution and regulated transmission and storage operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Accounting principles generally accepted in the United States require cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates.

We record regulatory assets as a component of other current assets and deferred charges and other assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded either on the face of the balance sheet or as a component of current liabilities, deferred income taxes or deferred credits and other liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Significant regulatory assets and liabilities as of September 30, 2011 and 2010 included the following:

	September 30 2011	September 30 2010
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefit costs	$254,666	$209,564
Merger and integration costs, net	6,242	6,714
Deferred gas costs	33,976	22,701
Regulatory cost of removal asset	8,852	31,014
Environmental costs	385	805
Rate case costs	4,862	4,505
Deferred franchise fees	379	1,161
Other	3,534	1,046
	$312,896	$277,510
Regulatory liabilities:		
Deferred gas costs	$ 8,130	$ 43,333
Regulatory cost of removal obligation	464,025	381,474
Other	14,025	6,112
	$486,180	$430,919

Currently, authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various state regulatory commissions. During the fiscal years ended September 30, 2011, 2010 and 2009, we recognized $0.5 million, $0.4 million and $0.4 million in amortization expense related to these costs.

Revenue recognition — Sales of natural gas to our natural gas distribution customers are billed on a monthly basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for natural gas distribution segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. During the year ended September 30, 2009 we recognized a non-recurring $7.6 million increase in gross profit associated with a one-time update to our estimate for gas delivered to customers but not yet billed, resulting from base rate changes in several jurisdictions.

On occasion, we are permitted to implement new rates that have not been formally approved by our state regulatory commissions, which are subject to refund. As permitted by accounting principles generally accepted in the United States, we recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas costs through purchased gas cost adjustment mechanisms. Purchased gas cost adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility company's non-gas costs. There is no gross profit generated through purchased gas cost adjustments, but they provide a dollar-for-dollar offset to increases or decreases in our natural gas distribution segment's gas costs. The effects of these purchased gas cost adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Operating revenues for our nonregulated segment and the associated carrying value of natural gas inventory (inclusive of storage costs) are recognized when we sell the gas and physically deliver it to our customers. Operating revenues include realized gains and losses arising from the settlement of financial instruments used in our nonregulated activities and unrealized gains and losses arising from changes in the fair value of natural gas inventory designated as a hedged item in a fair value hedge and the associated financial instruments. For the fiscal years ended September 30, 2011, 2010 and 2009, we included unrealized gains (losses) on open contracts of $(10.4) million, $(7.8) million and $(35.9) million as a component of nonregulated revenues.

Operating revenues for our regulated transmission and storage and nonregulated segments are recognized in the period in which actual volumes are transported and storage services are provided.

Cash and cash equivalents — We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts — Accounts receivable arise from natural gas sales to residential, commercial, industrial, municipal and other customers. For substantially all of our receivables, we establish an allowance for doubtful accounts based on our collection experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our natural gas distribution operations and natural gas held by our nonregulated segment to conduct their operations. The average cost method is used for all our regulated operations, except for certain jurisdictions in the Kentucky/Mid-States Division, where it is valued on the first-in first-out method basis, in accordance with regulatory requirements. Our nonregulated segment utilizes the average cost method; however, most of this inventory is hedged and is therefore reported at fair value at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Regulated property, plant and equipment — Regulated property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $1.7 million, $3.9 million and $4.9 million was capitalized in 2011, 2010 and 2009.

Major renewals, including replacement pipe, and betterments that are recoverable under our regulatory rate base are capitalized while the costs of maintenance and repairs that are not recoverable through rates are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the regulated plant in service account included in the rate base and depreciation begins.

Regulated property, plant and equipment is depreciated at various rates on a straight-line basis. These rates are approved by our regulatory commissions and are comprised of two components: one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.6 percent, 3.5 percent and 3.8 percent for the fiscal years ended September 30, 2011, 2010 and 2009.

Nonregulated property, plant and equipment — Nonregulated property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from three to 50 years.

Asset retirement obligations — We record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset. Accretion of the asset retirement obligation due to the passage of time is recorded as an operating expense.

As of September 30, 2011 and 2010, we recorded asset retirement obligations of $14.0 million and $11.4 million. Additionally, we recorded $5.4 million and $3.8 million of asset retirement costs as a component of property, plant and equipment that will be depreciated over the remaining life of the underlying associated assets.

We believe we have a legal obligation to retire our natural gas storage facilities. However, we have not recognized an asset retirement obligation associated with our storage facilities because we are not able to determine the settlement date of this obligation as we do not anticipate taking our storage facilities out of service permanently. Therefore, we cannot reasonably estimate the fair value of this obligation.

Impairment of long-lived assets — We periodically evaluate whether events or circumstances have occurred that indicate that other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded.

During fiscal 2011, we recorded pretax noncash impairment losses of $19.3 million related to our Fort Necessity storage project and $11.0 million related to our gathering system, as discussed in Note 5.

Goodwill and intangible assets — We annually evaluate our goodwill balances for impairment during our second fiscal quarter or more frequently as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. These calculations are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

Intangible assets are amortized over their useful lives of 10 years. These assets are reviewed for impairment as impairment indicators arise. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. No impairment has been recognized.

Marketable securities — As of September 30, 2011 and 2010, all of our marketable securities were classified as available-for-sale. In accordance with the authoritative accounting standards, these securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value.

Due to the deterioration of the financial markets in late calendar 2008 and early calendar 2009 and the uncertainty of a full recovery of these investments given the then current economic environment, we recorded a $5.4 million noncash charge to impair certain available-for-sale investments during fiscal 2009.

Financial instruments and hedging activities — We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically use financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. The objectives and strategies for the use of financial instruments are discussed in Note 4.

We record all of our financial instruments on the balance sheet at fair value, with changes in fair value ultimately recorded in the income statement. These financial instruments are reported as risk management assets and liabilities and are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying financial instrument.

The timing of when changes in fair value of our financial instruments are recorded in the income statement depends on whether the financial instrument has been designated and qualifies as a part of a hedging relationship or if regulatory rulings require a different accounting treatment. Changes in fair value for financial instruments that do not meet one of these criteria are recognized in the income statement as they occur.

Financial Instruments Associated with Commodity Price Risk

In our natural gas distribution segment, the costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with accounting principles generally accepted in the United States. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

In our nonregulated segment, we have designated most of the natural gas inventory held by this operating segment as the hedged item in a fair-value hedge. This inventory is marked to market at the end of each month based on the Gas Daily index, with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. The financial instruments associated with this natural gas inventory have been designated as fair-value hedges and are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. Changes in the spreads between the forward natural gas prices used to value the financial hedges designated against our physical inventory (NYMEX) and the market (spot) prices used to value our physical storage (Gas Daily) result in unrealized margins until the underlying physical gas is withdrawn and the related financial instruments are settled. Once the gas is withdrawn and the financial instruments are settled, the previously unrealized margins associated with these net positions are realized. We have elected to exclude this spot/forward differential for purposes of assessing the effectiveness of these fair-value hedges. Over time, we expect gains and losses on the sale of storage gas inventory to be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

In our nonregulated segment, we have elected to treat fixed-price forward contracts to deliver natural gas as normal purchases and normal sales. As such, these deliveries are recorded on an accrual basis in accordance with our revenue recognition policy. Financial instruments used to mitigate the commodity price risk associated with these contracts have been designated as cash flow hedges of anticipated purchases and sales at indexed prices. Accordingly, unrealized gains and losses on these open financial instruments are recorded as a component of accumulated other comprehensive income, and are recognized in earnings as a component of revenue when the hedged volumes are sold. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

Gains and losses from hedge ineffectiveness are recognized in the income statement. Fair value and cash flow hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the financial instruments is referred to as basis ineffectiveness. Ineffectiveness arising from changes in the fair value of the fair value hedges due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity is referred to as timing ineffectiveness.

In our nonregulated segment, we also utilize master netting agreements with significant counterparties that allow us to offset gains and losses arising from financial instruments that may be settled in cash with gains and losses arising from financial instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place. Additionally, the accounting guidance for master netting arrangements requires us to include the fair value of cash collateral or the obligation to return cash in the amounts that have been netted under master netting agreements used to offset gains and losses arising from financial instruments. As of September 30, 2011 and 2010, the Company netted $28.8 million and $24.9 million of cash held in margin accounts into its current risk management assets and liabilities.

Financial Instruments Associated with Interest Rate Risk

We periodically manage interest rate risk, typically when we issue new or refinance existing long-term debt. In fiscal 2011 and in prior years, we entered into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings. We designated these Treasury lock agreements as cash flow hedges at the time the agreements were executed. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income (loss). When the Treasury locks were settled, the realized gain or loss was recorded as a component of accumulated other comprehensive income (loss) and is being recognized as a component of interest expense over the life of the related financing arrangement. Hedge ineffectiveness to the extent incurred is reported as a component of interest expense.

Fair Value Measurements — We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily use quoted market prices and other observable market pricing information in valuing our financial assets and liabilities and minimize the use of unobservable pricing inputs in our measurements.

Prices actively quoted on national exchanges are used to determine the fair value of most of our assets and liabilities recorded on our balance sheet at fair value. Within our nonregulated operations, we utilize a mid-market pricing convention (the mid-point between the bid and ask prices) as a practical expedient for determining fair value measurement, as permitted under current accounting standards. Values derived from these sources reflect the market in which transactions involving these financial instruments are executed. We utilize models and other valuation methods to determine fair value when external sources are not available. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then-current market conditions. We believe the market prices and models used to value these assets and liabilities represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the assets and liabilities.

Fair-value estimates also consider our own creditworthiness and the creditworthiness of the counterparties involved. Our counterparties consist primarily of financial institutions and major energy companies. This concentration of counterparties may materially impact our exposure to credit risk resulting from market, economic or regulatory conditions. Adverse developments in the last few years in the global financial and credit markets have periodically made it more difficult and more expensive for companies to access the short-term capital markets, which may negatively impact the creditworthiness of our counterparties. Any further tightening of the credit markets could cause more of our counterparties to fail to perform. We seek to minimize counterparty credit risk through an evaluation of their financial condition and credit ratings and the use of collateral requirements under certain circumstances.

Amounts reported at fair value are subject to potentially significant volatility based upon changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our financial instruments. We believe the market prices and models used to value these financial instruments represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

Authoritative accounting literature establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to unadjusted quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). The levels of the hierarchy are described below:

Level 1 — Represents unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is defined as a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements consist primarily of exchange-traded financial instruments, gas stored underground that has been designated as the hedged item in a fair value hedge and our available-for-sale securities. The Level 1 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of exchange-traded financial instruments.

Level 2 — Represents pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable for the asset or liability as of the reporting date. These inputs are derived principally from, or corroborated by, observable market data. Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps and municipal and corporate bonds where market data for pricing is observable. The Level 2 measurements for investments in our Master Trust, Supplemental Executive Benefit Plan and postretirement benefit plan consist primarily of non-exchange traded financial instruments such as common collective trusts and investments in limited partnerships.

Level 3 — Represents generally unobservable pricing inputs which are developed based on the best information available, including our own internal data, in situations where there is little if any market activity for the asset or liability at the measurement date. The pricing inputs utilized reflect what a market participant would use to determine fair value. Our Master Trust has investments in real estate that qualify as Level 3 fair value measurements. Currently, we have no other assets or liabilities recorded at fair value that would qualify for Level 3 reporting.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. Through fiscal 2008, we reviewed the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. To comply with the new measurement date requirements established by the Financial Accounting Standards Board (FASB) and incorporated into accounting principles generally accepted in the United States, effective October 1, 2008, we changed our measurement date from June 30 to our fiscal year end, September 30. This change is more fully discussed in Note 9. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan (PAP) to new participants, effective October 1, 2010. Employees participating in the PAP as of October 1, 2010 were allowed to make a one-time election to migrate from the PAP into our defined contribution plan which was enhanced, effective January 1, 2011. Participants who chose to remain in the PAP will continue to earn benefits and interest allocations with no changes to their existing benefits.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on bonds available in the marketplace that are suitable for settling the obligations, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with currently available high quality corporate bonds.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of the annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan costs over a period of approximately ten to twelve years.

The market-related value of our plan assets represents the fair market value of the plan assets, adjusted to smooth out short-term market fluctuations over a five-year period. The use of this calculation will delay the impact of current market fluctuations on the pension expense for the period.

We estimate the assumed health care cost trend rate used in determining our annual postretirement net cost based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon the annual review of our participant census information as of the measurement date.

Income taxes — Income taxes are provided based on the liability method, which results in income tax assets and liabilities arising from temporary differences. Temporary differences are differences between the tax bases of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The liability method requires the effect of tax rate changes on current and accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

The Company may recognize the tax benefit from uncertain tax positions only if it is at least more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon settlement with the taxing authorities. We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements.

Stock-based compensation plans — We maintain the 1998 Long-Term Incentive Plan that provides for the granting of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units to officers, division presidents and other key employees. Non-employee directors are also eligible to receive stock-based compensation under the 1998 Long-Term Incentive Plan. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

Accumulated other comprehensive loss — Accumulated other comprehensive loss, net of tax, as of September 30, 2011 and 2010, consisted of the following unrealized gains (losses):

	September 30	
	2011	2010
	(In thousands)	
Unrealized holding gains on investments	$ 2,558	$ 4,205
Treasury lock agreements	(34,157)	(5,468)
Cash flow hedges	(16,861)	(22,109)
	$(48,460)	$(23,372)

Subsequent events — We have evaluated subsequent events from the September 30, 2011 balance sheet date through the date these financial statements were filed with the Securities and Exchange Commission. No events occurred subsequent to the balance sheet date that would require recognition or disclosure in the financial statements.

Recent accounting pronouncements — During the year ended September 30, 2011, two new accounting standards became applicable to the Company pertaining to goodwill impairment testing for reporting units with zero or negative carrying amounts and disclosure of supplementary pro forma information for business combinations. The adoption of these standards had no impact on our financial position, results of operations or cash flows. There were no other significant changes to our accounting policies during the year ended September 30, 2011.

For interim and annual periods beginning after December 15, 2011, three new accounting pronouncements will become applicable to the Company including guidance that will change certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements, guidance related to the presentation of other comprehensive income which will require that all nonowner changes in shareholders' equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements and new guidance related to goodwill impairment testing that will permit an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the traditional two-step goodwill impairment test. The adoption of these standards should not impact our financial position, results of operations or cash flows.

3. Goodwill and Intangible Assets

Goodwill and intangible assets were comprised of the following as of September 30, 2011 and 2010:

	September 30	
	2011	2010
	(In thousands)	
Goodwill	$740,000	$739,314
Intangible assets	207	834
Total	$740,207	$740,148

The following presents our goodwill balance allocated by segment and changes in the balance for the fiscal year ended September 30, 2011:

	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Total
	(In thousands)			
Balance as of September 30, 2010	$572,262	$132,341	$34,711	$739,314
Deferred tax adjustments on prior acquisitions(1)	646	40	—	686
Balance as of September 30, 2011	$572,908	$132,381	$34,711	$740,000

(1) During the preparation of the fiscal 2011 tax provision, we adjusted certain deferred taxes recorded in connection with acquisitions completed in fiscal 2001 and fiscal 2004, which resulted in an increase to goodwill and net deferred tax liabilities of $0.7 million.

Information regarding our intangible assets is reflected in the following table. As of September 30, 2011 and 2010, we had no intangible assets with indefinite lives.

		September 30, 2011			September 30, 2010		
	Useful Life (Years)	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
		(In thousands)					
Customer contracts	10	$6,926	$(6,719)	$207	$6,926	$(6,092)	$834

The following table presents actual amortization expense recognized during 2011 and an estimate of future amortization expense based upon our intangible assets at September 30, 2011.

Amortization expense (in thousands):	
Actual for the fiscal year ending September 30, 2011	$627
Estimated for the fiscal year ending:	
September 30, 2012	$ 43
September 30, 2013	43
September 30, 2014	43
September 30, 2015	43
September 30, 2016	35

4. Financial Instruments

We currently use financial instruments to mitigate commodity price risk. Additionally, we periodically utilize financial instruments to manage interest rate risk. The objectives and strategies for using financial instruments have been tailored to our regulated and nonregulated businesses. Currently, we utilize financial instruments in our natural gas distribution and nonregulated segments. We currently do not manage commodity price risk with financial instruments in our regulated transmission and storage segment.

Our financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when our financial instruments are in net liability positions.

As discussed in Note 2, we report our financial instruments as risk management assets and liabilities, each of which is classified as current or noncurrent based upon the anticipated settlement date of the underlying financial instrument. The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2011 and 2010:

	Natural Gas Distribution	Nonregulated (In thousands)	Total
September 30, 2011[3]			
Assets from risk management activities, current[1]	$ 843	$ 17,501	$ 18,344
Assets from risk management activities, noncurrent	998	—	998
Liabilities from risk management activities, current[1]	(11,916)	(3,537)	(15,453)
Liabilities from risk management activities, noncurrent	(67,862)	(10,227)	(78,089)
Net assets (liabilities)	$(77,937)	$ 3,737	$(74,200)
September 30, 2010			
Assets from risk management activities, current[2]	$ 2,219	$ 18,356	$ 20,575
Assets from risk management activities, noncurrent	47	890	937
Liabilities from risk management activities, current[2]	(48,942)	(731)	(49,673)
Liabilities from risk management activities, noncurrent	(2,924)	(6,000)	(8,924)
Net assets (liabilities)	$(49,600)	$ 12,515	$(37,085)

(1) Includes $28.8 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting arrangements and the remaining $16.4 million is classified as current risk management assets.

(2) Includes $24.9 million of cash held on deposit to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting arrangements and the remaining $12.3 million is classified as current risk management assets.

(3) The September 30, 2011 amounts are presented net of assets and liabilities held for sale in conjunction with the sale of our Iowa, Illinois and Missouri operations. At September 30, 2011, assets and liabilities held for sale included $1.3 million of current liabilities from risk management activities.

Regulated Commodity Risk Management Activities

Although our purchased gas cost adjustment mechanisms essentially insulate our natural gas distribution segment from commodity price risk, our customers are exposed to the effects of volatile natural gas prices. We manage this exposure through a combination of physical storage, fixed-price forward contracts and financial instruments, primarily over-the-counter swap and option contracts, in an effort to minimize the impact of natural gas price volatility on our customers during the winter heating season.

Our natural gas distribution gas supply department is responsible for executing this segment's commodity risk management activities in conformity with regulatory requirements. In jurisdictions where we are permitted to mitigate commodity price risk through financial instruments, the relevant regulatory authorities may establish the level of heating season gas purchases that can be hedged. Historically, if the regulatory authority does not establish this level, we seek to hedge between 25 and 50 percent of anticipated heating season gas purchases using financial instruments. For the 2010-2011 heating season (generally October through March), in the jurisdictions where we are permitted to utilize financial instruments, we hedged approximately 35 percent, or 31.7 Bcf of the winter flowing gas requirements at a weighted average cost of approximately $5.81 per Mcf. We have not designated these financial instruments as hedges.

The costs associated with and the gains and losses arising from the use of financial instruments to mitigate commodity price risk are included in our purchased gas cost adjustment mechanisms in accordance with regulatory requirements. Therefore, changes in the fair value of these financial instruments are initially recorded as a component of deferred gas costs and recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue in accordance with applicable authoritative accounting guidance. Accordingly, there is no earnings impact on our natural gas distribution segment as a result of the use of financial instruments.

Nonregulated Commodity Risk Management Activities

In our nonregulated operations, we aggregate and purchase gas supply, arrange transportation and/or storage logistics and ultimately deliver gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers' request.

We also perform asset optimization activities in our nonregulated segment. Through asset optimization activities, we seek to enhance our gross profit by maximizing the economic value associated with the storage and transportation capacity we own or control. We attempt to meet this objective by engaging in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial instruments at advantageous prices to lock in a gross profit margin. Through the use of transportation and storage services and financial instruments, we also seek to capture gross profit margin through the arbitrage of pricing differences that exist in various locations and by recognizing pricing differences that occur over time. Over time, gains and losses on the sale of storage gas inventory should be offset by gains and losses on the financial instruments, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

As a result of these activities, our nonregulated segment is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks through a combination of physical storage and financial instruments, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Future contracts provide the right to buy or sell the commodity at a fixed price in the future. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date.

We use financial instruments, designated as cash flow hedges of anticipated purchases and sales at index prices, to mitigate the commodity price risk in our nonregulated operations associated with deliveries under fixed-priced forward contracts to deliver gas to customers. These financial instruments have maturity dates ranging from one to 62 months. We use financial instruments, designated as fair value hedges, to hedge our natural gas inventory used in our asset optimization activities in our nonregulated segment.

Also, in nonregulated operations, we use storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. These financial instruments have not been designated as hedges.

Our nonregulated risk management activities are controlled through various risk management policies and procedures. Our Audit Committee has oversight responsibility for our nonregulated risk management limits and policies. A risk committee, comprised of corporate and business unit officers, is responsible for establishing and enforcing our nonregulated risk management policies and procedures.

Under our risk management policies, we seek to match our financial instrument positions to our physical storage positions as well as our expected current and future sales and purchase obligations in order to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Our operations can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur. At the close of business on September 30, 2011, our nonregulated segment had net open positions (including existing storage and related financial contracts) of 0.1 Bcf.

Interest Rate Risk Management Activities

We periodically manage interest rate risk by entering into Treasury lock agreements to fix the Treasury yield component of the interest cost associated with anticipated financings.

We intend to refinance our $250 million unsecured 5.125% Senior Notes that mature in January 2013 through the issuance of $350 million 30-year unsecured notes. In August 2011, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuances of these senior notes. We designated all of these Treasury locks as cash flow hedges.

In September 2010, we entered into three Treasury lock agreements to fix the Treasury yield component of the interest cost associated with $300 million of a total $400 million of senior notes that were issued in June 2011. This offering is discussed in Note 7. We designated these Treasury locks as cash flow hedges. The Treasury locks were settled on June 7, 2011 with the receipt of $20.1 million from the counterparties due to an increase in the 30-year Treasury lock rates between inception of the Treasury locks and settlement. Because the Treasury locks were effective, the net $12.6 million unrealized gain was recorded as a component of accumulated other comprehensive income and will be recognized as a component of interest expense over the 30-year life of the senior notes.

Additionally, our original fiscal 2011 financing plans included the issuance of $250 million of 30-year unsecured notes in November 2011 to fund our capital expenditure program. In September 2010, we entered into two Treasury lock agreements to fix the Treasury yield component of the interest cost associated with the anticipated issuance of these senior notes, which were designated as cash flow hedges. Due primarily to stronger than anticipated cash flows primarily resulting from the extension of the Bush tax cuts that allow the continued use of bonus depreciation on qualifying expenditures through December 31, 2011, the need to issue $250 million of debt in November was eliminated and the related Treasury lock agreements were unwound in March 2011. As a result of unwinding these Treasury locks, we recognized a pre-tax cash gain of $27.8 million during the second quarter of fiscal 2011.

In prior years, we entered into several Treasury lock agreements to fix the Treasury yield component of the interest cost of financing for various issuances of long-term debt and senior notes. The gains and losses realized upon settlement of these Treasury locks were recorded as a component of accumulated other comprehensive income (loss) when they were settled and are being recognized as a component of interest expense over the life of the associated notes from the date of settlement. The remaining amortization periods for the settled Treasury locks extends through fiscal 2041.

Quantitative Disclosures Related to Financial Instruments

The following tables present detailed information concerning the impact of financial instruments on our consolidated balance sheet and income statements.

As of September 30, 2011, our financial instruments were comprised of both long and short commodity positions. A long position is a contract to purchase the commodity, while a short position is a contract to sell the commodity. As of September 30, 2011, we had net long/(short) commodity contracts outstanding in the following quantities:

Contract Type	Hedge Designation	Natural Gas Distribution	Nonregulated
		Quantity (MMcf)	
Commodity contracts	Fair Value	—	(13,950)
	Cash Flow	—	38,713
	Not designated	26,977	31,648
		26,977	56,411

Financial Instruments on the Balance Sheet

The following tables present the fair value and balance sheet classification of our financial instruments by operating segment as of September 30, 2011 and 2010. As required by authoritative accounting literature, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include $28.8 million and $24.9 million of cash held on deposit in margin accounts as of September 30, 2011 and 2010 to collateralize certain financial instruments. Therefore, these gross balances are not indicative of either our actual credit exposure or net economic exposure. Additionally, the amounts below will not be equal to the amounts presented on our consolidated balance sheet, nor will they be equal to the fair value information presented for our financial instruments in Note 5.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2011				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 22,396	$ 22,396
Noncurrent commodity contracts	Deferred charges and other assets	—	174	174
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(31,064)	(31,064)
Noncurrent commodity contracts	Deferred credits and other liabilities	(67,527)	(7,709)	(75,236)
Total		(67,527)	(16,203)	(83,730)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	843	67,710	68,553
Noncurrent commodity contracts	Deferred charges and other assets	998	22,379	23,377
Liability Financial Instruments				
Current commodity contracts	Other current liabilities[1]	(13,256)	(73,865)	(87,121)
Noncurrent commodity contracts	Deferred credits and other liabilities	(335)	(25,071)	(25,406)
Total		(11,750)	(8,847)	(20,597)
Total Financial Instruments		$(79,277)	$(25,050)	$(104,327)

(1) Other current liabilities not designated as hedges in our natural gas distribution segment include $1.3 million related to risk management liabilities that were classified as assets held for sale at September 30, 2011.

	Balance Sheet Location	Natural Gas Distribution	Nonregulated	Total
			(In thousands)	
September 30, 2010				
Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	$ —	$ 40,030	$ 40,030
Noncurrent commodity contracts	Deferred charges and other assets	—	2,461	2,461
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	—	(56,575)	(56,575)
Noncurrent commodity contracts	Deferred credits and other liabilities	—	(9,222)	(9,222)
Total		—	(23,306)	(23,306)
Not Designated As Hedges:				
Asset Financial Instruments				
Current commodity contracts	Other current assets	2,219	16,459	18,678
Noncurrent commodity contracts	Deferred charges and other assets	47	2,056	2,103
Liability Financial Instruments				
Current commodity contracts	Other current liabilities	(48,942)	(7,178)	(56,120)
Noncurrent commodity contracts	Deferred credits and other liabilities	(2,924)	(405)	(3,329)
Total		(49,600)	10,932	(38,668)
Total Financial Instruments		$(49,600)	$(12,374)	$(61,974)

Impact of Financial Instruments on the Income Statement

Hedge ineffectiveness for our nonregulated segment is recorded as a component of unrealized gross profit and primarily results from differences in the location and timing of the derivative instrument and the hedged item. Hedge ineffectiveness could materially affect our results of operations for the reported period. For the years ended September 30, 2011, 2010 and 2009 we recognized a gain arising from fair value and cash flow hedge ineffectiveness of $24.8 million, $51.8 million and $6.4 million. Additional information regarding ineffectiveness recognized in the income statement is included in the tables below.

Fair Value Hedges

The impact of our nonregulated commodity contracts designated as fair value hedges and the related hedged item on our consolidated income statement for the years ended September 30, 2011, 2010 and 2009 is presented below.

	Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands)		
Commodity contracts	$16,552	$34,650	$ 45,120
Fair value adjustment for natural gas inventory designated as the hedged item	9,824	19,867	(28,831)
Total impact on revenue	$26,376	$54,517	$ 16,289
The impact on revenue is comprised of the following:			
Basis ineffectiveness	$ 803	$ (1,272)	$ 5,958
Timing ineffectiveness	25,573	55,789	10,331
	$26,376	$54,517	$ 16,289

Basis ineffectiveness arises from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments. Timing ineffectiveness arises due to changes in the difference between the spot price and the futures price, as well as the difference between the timing of the settlement of the futures and the valuation of the underlying physical commodity. As the commodity contract nears the settlement date, spot-to-forward price differences should converge, which should reduce or eliminate the impact of this ineffectiveness on revenue.

Cash Flow Hedges

The impact of cash flow hedges on our consolidated income statements for the years ended September 30, 2011, 2010 and 2009 is presented below. Note that this presentation does not reflect the financial impact arising from the hedged physical transaction. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	Fiscal Year Ended September 30, 2011			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(28,430)	$(28,430)
Loss arising from ineffective portion of commodity contracts	—	—	(1,585)	(1,585)
Total impact on revenue	—	—	(30,015)	(30,015)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,455)	—	—	(2,455)
Gain on unwinding of Treasury lock reclassified from AOCI into miscellaneous income	21,803	6,000	—	27,803
Total impact from cash flow hedges	$19,348	$6,000	$(30,015)	$ (4,667)

	Fiscal Year Ended September 30, 2010			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(44,809)	$(44,809)
Loss arising from ineffective portion of commodity contracts	—	—	(2,717)	(2,717)
Total impact on revenue	—	—	(47,526)	(47,526)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(2,678)	—	—	(2,678)
Total impact from cash flow hedges	$(2,678)	$ —	$(47,526)	$(50,204)

	Fiscal Year Ended September 30, 2009			
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Consolidated
	(In thousands)			
Loss reclassified from AOCI into revenue for effective portion of commodity contracts	$ —	$ —	$(136,540)	$(136,540)
Loss arising from ineffective portion of commodity contracts	—	—	(9,888)	(9,888)
Total impact on revenue	—	—	(146,428)	(146,428)
Net loss on settled Treasury lock agreements reclassified from AOCI into interest expense	(4,070)	—	—	(4,070)
Total impact from cash flow hedges	$(4,070)	$ —	$(146,428)	$(150,498)

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss), net of taxes, for the years ended September 30, 2011 and 2010. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the income statement as incurred.

	Fiscal Year Ended September 30	
	2011	2010
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$(12,720)	$ 343
Forward commodity contracts	(12,096)	(34,296)
Recognition of (gains) losses in earnings due to settlements:		
Treasury lock agreements	(15,969)	1,687
Forward commodity contracts	17,344	27,333
Total other comprehensive loss from hedging, net of tax[1]	$(23,441)	$ (4,933)

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Deferred gains (losses) recorded in AOCI associated with our Treasury lock agreements are recognized in earnings as they are amortized, while deferred losses associated with commodity contracts are recognized in earnings upon settlement. The following amounts, net of deferred taxes, represent the expected recognition in earnings of the deferred gains (losses) recorded in AOCI associated with our financial instruments, based upon the fair values of these financial instruments as of September 30, 2011. However, the table below does not include the expected recognition in earnings of the Treasury lock agreements entered into in August 2011 as those financial instruments have not yet settled.

	Treasury Lock Agreements	Commodity Contracts	Total
		(In thousands)	
2012	$ (1,266)	$(12,160)	$(13,426)
2013	(1,266)	(3,214)	(4,480)
2014	(1,266)	(1,461)	(2,727)
2015	601	(29)	572
2016	770	3	773
Thereafter	10,812	—	10,812
Total[1]	$ 8,385	$(16,861)	$ (8,476)

[1] Utilizing an income tax rate ranging from 37 percent to 39 percent based on the effective rates in each taxing jurisdiction.

Financial Instruments Not Designated as Hedges

The impact of financial instruments that have not been designated as hedges on our consolidated income statements for the years ended September 30, 2011, 2010 and 2009 was an increase (decrease) in revenue of $(1.4) million, $15.4 million and $36.9 million. Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments. Therefore, this presentation is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

As discussed above, financial instruments used in our natural gas distribution segment are not designated as hedges. However, there is no earnings impact on our natural gas distribution segment as a result of the use of these financial instruments because the gains and losses arising from the use of these financial instruments are recognized in the consolidated statement of income as a component of purchased gas cost when the related costs are recovered through our rates and recognized in revenue. Accordingly, the impact of these financial instruments is excluded from this presentation.

5. Fair Value Measurements

We report certain assets and liabilities at fair value, which is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We record cash and cash equivalents, accounts receivable and accounts payable at carrying value, which substantially approximates fair value due to the short-term nature of these assets and liabilities. For other financial assets and liabilities, we primarily use quoted market prices and other observable market pricing information to minimize the use of unobservable pricing inputs in our measurements when determining fair value. The methods used to determine fair value for our assets and liabilities are fully described in Note 2.

Fair value measurements also apply to the valuation of our pension and post-retirement plan assets. The fair value of these assets is presented in Note 9 below.

Quantitative Disclosures

Financial Instruments

The classification of our fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. The following tables summarize, by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2011 and 2010. As required under authoritative accounting literature, assets and liabilities are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[2]	September 30, 2011
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 1,841	$ —	$ —	$ 1,841
Nonregulated segment	15,262	97,396	—	(95,156)	17,502
Total financial instruments	15,262	99,237	—	(95,156)	19,343
Hedged portion of gas stored underground	47,940	—	—	—	47,940
Available-for-sale securities					
Money market funds	—	1,823	—	—	1,823
Registered investment companies	36,444	—	—	—	36,444
Bonds	—	14,366	—	—	14,366
Total available-for-sale securities	36,444	16,189	—	—	52,633
Total assets	$99,646	$115,426	$ —	$ (95,156)	$119,916
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$ 81,118	$ —	$ —	$ 81,118
Nonregulated segment	22,091	115,617	—	(123,943)	13,765
Total liabilities	$22,091	$196,735	$ —	$(123,943)	$ 94,883

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)[1]	Significant Other Unobservable Inputs (Level 3)	Netting and Cash Collateral[3]	September 30, 2010
			(In thousands)		
Assets:					
Financial instruments					
Natural gas distribution segment	$ —	$ 2,266	$ —	$ —	$ 2,266
Nonregulated segment	18,544	42,462	—	(41,760)	19,246
Total financial instruments	18,544	44,728	—	(41,760)	21,512
Hedged portion of gas stored underground	57,507	—	—	—	57,507
Available-for-sale securities					
Money market funds	—	499	—	—	499
Registered investment companies	40,967	—	—	—	40,967
Total available-for-sale securities	40,967	499	—	—	41,466
Total assets	$117,018	$45,227	$ —	$(41,760)	$120,485
Liabilities:					
Financial instruments					
Natural gas distribution segment	$ —	$51,866	$ —	$ —	$ 51,866
Nonregulated segment	41,430	31,950	—	(66,649)	6,731
Total liabilities	$ 41,430	$83,816	$ —	$(66,649)	$ 58,597

(1) Our Level 2 measurements primarily consist of non-exchange-traded financial instruments, such as over-the-counter options and swaps where market data for pricing is observable. The fair values for these assets and liabilities are determined using a market-based approach in which observable market prices are adjusted for criteria specific to each instrument, such as the strike price, notional amount or basis differences. This level also includes municipal and corporate bonds where market data for pricing is observable.

(2) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2011 we had $28.8 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.4 million was used to offset current risk management liabilities under master netting agreements and the remaining $16.4 million is classified as current risk management assets.

(3) This column reflects adjustments to our gross financial instrument assets and liabilities to reflect netting permitted under our master netting agreements and the relevant authoritative accounting literature. In addition, as of September 30, 2010 we had $24.9 million of cash held in margin accounts to collateralize certain financial instruments. Of this amount, $12.6 million was used to offset current risk management liabilities under master netting agreements and the remaining $12.3 million is classified as current risk management assets.

Available-for-sale securities are comprised of the following:

	Amortized Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In thousands)		
As of September 30, 2011:				
Domestic equity mutual funds	$27,748	$4,074	$ —	$31,822
Foreign equity mutual funds	4,597	267	(242)	4,622
Bonds	14,390	10	(34)	14,366
Money market funds	1,823	—	—	1,823
	$48,558	$4,351	$(276)	$52,633
As of September 30, 2010:				
Domestic equity mutual funds	$29,540	$5,698	$ —	$35,238
Foreign equity mutual funds	4,753	976	—	5,729
Money market funds	499	—	—	499
	$34,792	$6,674	$ —	$41,466

At September 30, 2011 and 2010, our available-for-sale securities included $38.3 million and $41.5 million related to assets held in separate rabbi trusts for our supplemental executive benefit plans as discussed in Note 9. At September 30, 2011 we maintained investments in bonds that have contractual maturity dates ranging from January 2012 through January 2016.

We maintained an investment in one foreign equity mutual fund with a fair value of $2.3 million in an unrealized loss position of $0.2 million as of September 30, 2011. This fund has been in an unrealized loss position for less than twelve months. Because this fund is only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold this investment, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that this fund continues to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other-than-temporary as of September 30, 2011. We also maintained several bonds with a cumulative fair value of $9.9 million in an unrealized loss position of less than $0.1 million as of September 30, 2011. These bonds have been in an unrealized loss position for less than twelve months. Based upon our intent and ability to hold these investments, our ability to direct the source of the payments in order to maximize the life of the portfolio, the short-term nature of the decline in fair value and the fact that these bonds are investment-grade, we do not consider this impairment to be other-than-temporary as of September 30, 2011.

At September 30, 2010, we did not maintain any investments that were in an unrealized loss position. In fiscal 2009, we recorded a $5.4 million noncash charge to impair certain available-for sale investments during the year ended September 30, 2009 due to the conditions of the financial markets at that time.

Other Fair Value Measures

In addition to the financial instruments above, we have several financial and nonfinancial assets and liabilities subject to fair value measures. These financial assets and liabilities include cash and cash equivalents, accounts receivable, accounts payable and debt. The nonfinancial assets and liabilities include asset retirement obligations and pension and post-retirement plan assets. We record cash and cash equivalents, accounts receivable, accounts payable and debt at carrying value. For cash and cash equivalents, accounts receivable and accounts payable, we consider carrying value to materially approximate fair value due to the short-term nature of these assets and liabilities.

Atmos Gathering Company (AGC) owns and operates the Park City and Shrewsbury gathering systems in Kentucky. The Park City gathering system consists of a 23-mile low pressure pipeline and a nitrogen removal unit that was constructed in 2008. The Shrewsbury production, gathering and processing assets were acquired in 2008 at which time we sold the production assets to a third party. As a result of the sale of the production assets, we obtained a 10-year production payment note under which we were to be paid from future production generated from the assets.

As discussed in Note 13, AGC is involved in an ongoing lawsuit with the Park City gathering system. Due to the lawsuit and a low natural gas price environment, the assets have generated operating losses. As a result of these developments, we performed an impairment assessment of these assets during the third fiscal quarter and determined the assets to be impaired. We reduced the carrying value of the assets to their estimated fair value of approximately $6 million and recorded a pre-tax noncash impairment loss of approximately $11 million. We used a combination of a market and income approach in a weighted average discounted cash flow analysis that included significant inputs such as our weighted average cost of capital and assumptions regarding future natural gas prices. This is a Level 3 fair value measurement because the inputs used are unobservable. Based on this analysis, we determined the assets to be impaired.

In February 2008, Atmos Pipeline and Storage, LLC, a subsidiary of AEH, announced plans to construct and operate a salt-cavern storage project in Franklin Parish, Louisiana. In March 2010, we entered into an option and acquisition agreement with a third party, which provided the third party with the exclusive option to develop the proposed Fort Necessity salt-dome natural gas storage project. In July 2010, we agreed with the third party to extend the option period to March 2011. In January 2011, the third party developer notified us that it did not plan to commence the activities required to allow it to exercise the option by March 2011; accordingly, the option was terminated. We evaluated our strategic alternatives and concluded the project's returns did not meet our investment objectives. Accordingly, in March 2011, we recorded a $19.3 million pretax noncash impairment loss to write off substantially all of our investment in the project.

Our debt is recorded at carrying value. The fair value of our debt is determined using third party market value quotations. The following table presents the carrying value and fair value of our debt as of September 30, 2011:

	September 30, 2011
	(In thousands)
Carrying Amount	$2,212,565
Fair Value	$2,560,945

6. Discontinued Operations

On May 12, 2011, we entered into a definitive agreement to sell all of our natural gas distribution assets located in Missouri, Illinois and Iowa to Liberty Energy (Midstates) Corporation, an affiliate of Algonquin Power & Utilities Corp. for a cash price of approximately $124 million. The agreement contains terms and conditions customary for transactions of this type, including typical adjustments to the purchase price at closing, if applicable. The closing of the transaction is subject to the satisfaction of customary conditions including the receipt of applicable regulatory approvals.

As required under generally accepted accounting principles, the operating results of our Missouri, Illinois and Iowa operations have been aggregated and reported on the consolidated statements of income as income from discontinued operations, net of income tax. Expenses related to general corporate overhead and interest expense allocated to their operations are not included in discontinued operations.

The tables below set forth selected financial and operational information related to net assets and operating results related to discontinued operations. Additionally, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2011. Prior period revenues and expenses associated with these assets have been reclassified into discontinued operations. This reclassification had no impact on previously reported net income.

The following table presents statement of income data related to discontinued operations.

	Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Operating revenues	$80,028	$69,855	$99,969
Purchased gas cost	48,759	42,419	72,945
Gross profit	31,269	27,436	27,024
Operating expenses	16,854	15,151	15,988
Operating income	14,415	12,285	11,036
Other nonoperating expense	(196)	(294)	(428)
Income from discontinued operations before income taxes	14,219	11,991	10,608
Income tax expense	5,502	4,425	2,929
Net income	$ 8,717	$ 7,566	$ 7,679

The following table presents balance sheet data related to assets held for sale.

	September 30, 2011
	(In thousands)
Net plant, property & equipment	$127,577
Gas stored underground	11,931
Other current assets	786
Deferred charges and other assets	277
Assets held for sale	$140,571
Accounts payable and accrued liabilities	$ 1,917
Other current liabilities	4,877
Regulatory cost of removal	10,498
Deferred credits and other liabilities	1,153
Liabilities held for sale	$ 18,445

7. Debt

Long-term debt

Long-term debt at September 30, 2011 and 2010 consisted of the following:

	2011	2010
	(In thousands)	
Unsecured 7.375% Senior Notes, redeemed May 2011	$ —	$ 350,000
Unsecured 10% Notes, due December 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 6.35% Senior Notes, due 2017	250,000	250,000
Unsecured 8.50% Senior Notes, due 2019	450,000	450,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Unsecured 5.50% Senior Notes, due 2041	400,000	—
Medium term notes		
Series A, 1995-2, 6.27%, redeemed December 2010	—	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
Rental property term notes due in installments through 2013	262	393
Total long-term debt	2,212,565	2,172,696
Less:		
Original issue discount on unsecured senior notes and debentures	(4,014)	(3,014)
Current maturities	(2,434)	(360,131)
	$2,206,117	$1,809,551

As noted above, our unsecured 10% notes will mature in December 2011; accordingly, these have been classified within the current maturities of long-term debt.

Our $350 million 7.375% senior notes were paid on their maturity date on May 15, 2011, using commercial paper borrowings. We replaced these senior notes on June 10, 2011 with $400 million 5.50% senior notes. The effective interest rate on these notes is 5.381 percent, after giving effect to offering costs and the settlement of the $300 million Treasury locks discussed in Note 4. Substantially all of the net proceeds of approximately $394 million was used to repay $350 million of outstanding commercial paper. The remainder of the net proceeds was used for general corporate purposes.

Short-term debt

Our short-term borrowing requirements are affected by the seasonal nature of the natural gas business. Changes in the price of natural gas and the amount of natural gas we need to supply our customers' needs could significantly affect our borrowing requirements. Our short-term borrowings typically reach their highest levels in the winter months.

Prior to the third quarter of fiscal 2011, we financed our short-term borrowing requirements through a combination of a $566.7 million commercial paper program and four committed revolving credit facilities with third-party lenders that provided approximately $1.0 billion of working capital funding. On April 13, 2011, our $200 million 180-day unsecured credit facility expired and was not replaced. On May 2, 2011, we replaced our $566.7 million unsecured credit facility with a new five-year $750 million unsecured credit facility with an accordion feature that could increase our borrowing capacity to $1.0 billion. On September 30, 2011, we renewed our 364-day revolving line of credit facility used to backstop letters of credit for our regulated operations and increased the borrowing capacity from $6.25 million to $10 million. As a result of these changes, we have $985 million of working capital funding from our commercial paper program and four committed revolving credit facilities with third-party lenders.

At September 30, 2011 and 2010, there was $206.4 million and $126.1 million outstanding under our commercial paper program. As of September 30, 2011 our commercial paper had maturities of less than one week with interest rates of 0.29 percent. We also use intercompany credit facilities to supplement the funding provided by these third-party committed credit facilities. These facilities are described in greater detail below.

Regulated Operations

We fund our regulated operations as needed, primarily through our commercial paper program and three committed revolving credit facilities with third-party lenders that provide approximately $785 million of working capital funding. The first facility is a five-year $750 million unsecured facility, expiring May 2016, that bears interest at a base rate or at a LIBOR-based rate for the applicable interest period, plus a spread ranging from zero percent to 2 percent, based on the Company's credit ratings. This credit facility serves as a backup liquidity facility for our commercial paper program. At September 30, 2011, there were no borrowings under this facility, but we had $206.4 million of commercial paper outstanding leaving $543.6 million available.

The second facility is a $25 million unsecured facility that bears interest at a daily negotiated rate, generally based on the Federal Funds rate plus a variable margin. At September 30, 2011, there were no borrowings outstanding under this facility.

The third facility is a $10 million revolving credit facility used primarily to issue letters of credit that bears interest at a LIBOR-based rate. At September 30, 2011, there were no borrowings outstanding under this credit facility; however, letters of credit totaling $5.9 million had been issued under the facility at September 30, 2011, which reduced the amount available by a corresponding amount.

The availability of funds under these credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in each of these facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At September 30, 2011, our total-debt-to-total-capitalization ratio, as defined, was 54 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under each of these facilities are subject to adjustment depending upon our credit ratings.

In addition to these third-party facilities, our regulated operations have a $350 million intercompany revolving credit facility with AEH. This facility bears interest at the lower of (i) the one-month LIBOR rate plus 0.45 percent or (ii) the marginal borrowing rate available to the Company on the date of borrowing. The marginal borrowing rate is defined as the lower of (i) a rate based upon the lower of the Prime Rate or the Eurodollar rate under the five year revolving credit facility or (ii) the lowest rate outstanding under the commercial paper program. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There was $181.3 million outstanding under this facility at September 30, 2011.

Nonregulated Operations

Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH, has a three-year $200 million committed revolving credit facility with a syndicate of third-party lenders with an accordion feature that could increase AEM's borrowing capacity to $500 million. The credit facility is primarily used to issue letters of credit and, on a less frequent basis, to borrow funds for gas purchases and other working capital needs.

At AEM's option, borrowings made under the credit facility are based on a base rate or an offshore rate, in each case plus an applicable margin. The base rate is a floating rate equal to the higher of: (a) 0.50 percent per annum above the latest federal funds rate; (b) the per annum rate of interest established by BNP Paribas from time to time as its "prime rate" or "base rate" for U.S. dollar loans; (c) an offshore rate (based on LIBOR with a three-month interest period) as in effect from time to time; or (d) the "cost of funds" rate which is the cost of funds as reasonably determined by the administrative agent. The offshore rate is a floating rate equal to the higher of (a) an offshore rate based upon LIBOR for the applicable interest period; or (b) a "cost of funds" rate referred to above. In the case of both base rate and offshore rate loans, the applicable margin ranges from 1.875 percent to 2.25 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. This facility has swing line loan features, which allow AEM to borrow, on a same day basis, an amount ranging from $6 million to $30 million based on the terms of an election within the agreement. This facility is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

At September 30, 2011, there were no borrowings outstanding under this credit facility. However, at September 30, 2011, AEM letters of credit totaling $20.2 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $129.8 million at September 30, 2011.

AEM is required by the financial covenants in this facility to maintain a ratio of total liabilities to tangible net worth that does not exceed a maximum of 5 to 1. At September 30, 2011, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.33 to 1. Additionally, AEM must maintain minimum levels of net working capital and net worth ranging from $20 million to $40 million. As defined in the financial covenants, at September 30, 2011, AEM's net working capital was $131.8 million and its tangible net worth was $144.5 million.

To supplement borrowings under this facility, AEH has a $350 million intercompany demand credit facility with AEC, which bears interest at a rate equal to the greater of (i) the one-month LIBOR rate plus 3.00 percent or (ii) the rate for AEM's offshore borrowings under its committed credit facility plus 0.75 percent. Applicable state regulatory commissions have approved our use of this facility through December 31, 2011. There were no borrowings outstanding under this facility at September 30, 2011.

Shelf Registration

We have an effective shelf registration statement with the Securities and Exchange Commission (SEC) that permits us to issue a total of $1.3 billion in common stock and/or debt securities. The shelf registration statement has been approved by all requisite state regulatory commissions. Due to certain restrictions imposed by one state regulatory commission on our ability to issue securities under the new registration statement, we were able to issue a total of $950 million in debt securities and $350 million in equity securities prior to our $400 million senior notes offering in June 2011. At September 30, 2011, $900 million remains available for issuance. Of this amount, $550 million is available for the issuance of debt securities and $350 million remains available for the issuance of equity securities under the shelf until March 2013.

Debt Covenants

In addition to the financial covenants described above, our credit facilities and public indentures contain usual and customary covenants for our business, including covenants substantially limiting liens, substantial asset sales and mergers.

Additionally, our public debt indentures relating to our senior notes and debentures, as well as our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity.

Further, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate.

Finally, AEM's credit agreement contains a provision that would limit the amount of credit available if Atmos Energy were downgraded below an S&P rating of BBB and a Moody's rating of Baa2. We have no other triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity, based on our credit rating or other triggering events.

We were in compliance with all of our debt covenants as of September 30, 2011. If we were unable to comply with our debt covenants, we would likely be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions.

Maturities of long-term debt at September 30, 2011 were as follows (in thousands):

2012	$ 2,434
2013	250,131
2014	—
2015	500,000
2016	—
Thereafter	1,460,000
	$2,212,565

8. Stock and Other Compensation Plans

Share Repurchase Agreement

On, July 1, 2010, we entered into an accelerated share repurchase agreement with Goldman Sachs & Co. under which we repurchased $100 million of our outstanding common stock in order to offset stock grants made under our various employee and director incentive compensation plans. We paid $100 million to Goldman Sachs & Co. on July 7, 2010 in a share forward transaction and received 2,958,580 shares of Atmos Energy common stock. On March 4, 2011, we received and retired an additional 375,468 common shares which concluded our share repurchase agreement. In total, we received and retired 3,334,048 common shares under the repurchase agreement. The final number of shares we ultimately repurchased in the transaction was based generally on the average of the effective share repurchase price of our common stock over the duration of the agreement, which was $29.99. As a result of this transaction, beginning in our fourth quarter of fiscal 2010, the number of outstanding shares used to calculate our earnings per share was reduced by the number of shares received and the $100 million purchase price was recorded as a reduction in shareholders' equity.

Share Repurchase Program

On September 28, 2011 our Board of Directors approved a new program authorizing the repurchase of up to five million shares of common stock over a five-year period. Although the program is authorized for a five-year period, it may be terminated or limited at any time. Shares may be repurchased in the open market or in privately negotiated transactions in amounts the company deems appropriate. The program is primarily intended to minimize the dilutive effect of equity grants under various benefit related incentive compensation plans of the company.

Stock-Based Compensation Plans

Total stock-based compensation expense was $11.6 million, $12.7 million and $14.5 million for the fiscal years ended September 30, 2011, 2010 and 2009, primarily related to restricted stock costs.

1998 Long-Term Incentive Plan

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan (LTIP), which became effective in October 1998 after approval by our shareholders. The LTIP is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units to certain employees and non-employee directors of the Company and our subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock.

As of September 30, 2011, we are authorized to grant awards for up to a maximum of 6.5 million shares of common stock under this plan subject to certain adjustment provisions. In February 2011, shareholders voted to increase the number of authorized LTIP shares by 2.2 million shares. On October 19, 2011, we received all required state regulatory approvals to increase the maximum number of authorized LTIP shares to 8.7 million shares, subject to certain adjustment provisions. On October 28, 2011, we filed with the SEC a registration statement on Form S-8 to register an additional 2.2 million shares; we also listed such shares with the New York Stock Exchange. As of September 30, 2011, non-qualified stock options, bonus stock, time-lapse restricted stock, time-lapse restricted stock units, performance-based restricted stock units and stock units had been issued under this plan, and 319,700 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years. However, no stock options have been granted under this plan since fiscal 2003, except for a limited number of options that were converted from bonuses paid under our Annual Incentive Plan, the last of which occurred in fiscal 2006.

Restricted Stock Plans

As noted above, the LTIP provides for discretionary awards of restricted stock units to help attract, retain and reward employees of Atmos Energy and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time and the achievement of specified performance targets. The fair value of the awards granted is based on the market price of our stock at the date of grant. The associated expense is recognized ratably over the vesting period.

Employees who are granted shares of time-lapse restricted stock under our LTIP have a nonforfeitable right to dividends that are paid at the same rate at which they are paid on shares of stock without restrictions. In addition, employees who are granted shares of time-lapse restricted stock units under our LTIP have a nonforfeitable right to dividend equivalents that are paid at the same rate at which they are paid on shares of stock without restrictions. Both time-lapse restricted stock and time-lapse restricted stock units contain only a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions). There are no performance conditions required to be met for employees to be vested in either the time-lapse restricted stock or time-lapse restricted stock units.

Employees who are granted shares of performance-based restricted stock units under our LTIP have a forfeitable right to dividends that accrue at the same rate at which they are paid on shares of stock without restrictions. Dividends on the performance-based restricted stock units are paid in the form of shares upon the vesting of the award. Performance-based restricted stock units contain a service condition that the employee recipients render continuous services to the Company for a period of three years from the date of grant, except for accelerated vesting in the event of death, disability, change of control of the Company or termination without cause (with certain exceptions) and a performance condition based on a cumulative earnings per share target amount.

The following summarizes information regarding the restricted stock issued under the plan during the fiscal years ended September 30, 2011, 2010 and 2009:

	2011		2010		2009	
	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of year	1,293,960	$27.28	1,295,841	$27.23	1,096,770	$29.04
Granted	491,345	33.10	551,278	29.07	711,909	25.76
Vested	(464,321)	27.21	(493,957)	29.24	(499,267)	29.05
Forfeited	(56,842)	27.56	(59,202)	26.54	(13,571)	28.92
Nonvested at end of year	1,264,142	$29.56	1,293,960	$27.28	1,295,841	$27.23

As of September 30, 2011, there was $18.0 million of total unrecognized compensation cost related to nonvested time-lapse restricted shares and restricted stock units granted under the LTIP. That cost is expected to be recognized over a weighted-average period of 1.5 years. The fair value of restricted stock vested during the fiscal years ended September 30, 2011, 2010 and 2009 was $12.6 million, $14.4 million and $14.5 million.

Stock Option Plan

A summary of stock option activity under the LTIP follows:

	2011		2010		2009	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	434,962	$22.46	611,227	$21.88	913,841	$22.54
Granted	—	—	—	—	—	—
Exercised	(348,196)	22.54	(176,265)	20.44	(130,965)	21.99
Forfeited	—	—	—	—	—	—
Expired	—	—	—	—	(171,649)	25.31
Outstanding at end of year[(1)]	86,766	$22.16	434,962	$22.46	611,227	$21.88
Exercisable at end of year[(2)]	86,766	$22.16	434,962	$22.46	611,227	$21.88

(1) The weighted-average remaining contractual life for outstanding options was 1.7 years, 1.6 years, and 2.4 years for fiscal years 2011, 2010 and 2009. The aggregate intrinsic value of outstanding options was $0.3 million, $1.6 million and $2.1 million for fiscal years 2011, 2010 and 2009.

(2) The weighted-average remaining contractual life for exercisable options was 1.7 years, 1.6 years and 2.4 years for fiscal years 2011, 2010 and 2009. The aggregate intrinsic value of exercisable options was $0.3 million, $1.6 million and $2.1 million for the fiscal years 2011, 2010 and 2009.

Information about outstanding and exercisable options under the LTIP, as of September 30, 2011, is reflected in the following tables:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price
$21.23 to $22.99	71,064	1.4	$21.31
$23.00 to $26.19	15,702	3.3	$26.00
$21.23 to $26.19	86,766	1.7	$22.16

	Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands, except per share data)		
Grant date weighted average fair value per share	$ —	$ —	$ —
Net cash proceeds from stock option exercises	$7,848	$3,604	$2,880
Income tax benefit from stock option exercises	$1,010	$ 547	$ 177
Total intrinsic value of options exercised	$1,263	$ 239	$ 262

As of September 30, 2011, there was no unrecognized compensation cost related to nonvested stock options.

Other Plans

Direct Stock Purchase Plan

We maintain a Direct Stock Purchase Plan, open to all investors, which allows participants to have all or part of their cash dividends paid quarterly in additional shares of our common stock. The minimum initial investment required to join the plan is $1,250. Direct Stock Purchase Plan participants may purchase additional shares of our common stock as often as weekly with voluntary cash payments of at least $25, up to an annual maximum of $100,000.

Outside Directors Stock-For-Fee Plan

In November 1994, the Board of Directors adopted the Outside Directors Stock-for-Fee Plan which was approved by our shareholders in February 1995. The plan permits non-employee directors to receive all or part of their annual retainer and meeting fees in stock rather than in cash.

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

In November 1998, the Board of Directors adopted the Equity Incentive and Deferred Compensation Plan for Non-Employee Directors which was approved by our shareholders in February 1999. This plan amended the Atmos Energy Corporation Deferred Compensation Plan for Outside Directors adopted by the Company in May 1990 and replaced the pension payable under our Retirement Plan for Non-Employee Directors. The plan provides non-employee directors of Atmos Energy with the opportunity to defer receipt, until retirement, of compensation for services rendered to the Company, invest deferred compensation into either a cash account or a stock account and to receive an annual grant of share units for each year of service on the Board.

Other Discretionary Compensation Plans

We adopted the Variable Pay Plan in fiscal 1999 for our regulated segments' employees to give each employee an opportunity to share in our financial success based on the achievement of key performance measures considered critical to achieving business objectives for a given year and has minimum and maximum thresholds. The plan must meet the minimum threshold for the plan to be funded and distributed to employees. These performance measures may include earnings growth objectives, improved cash flow objectives or crucial customer satisfaction and safety results. We monitor progress towards the achievement of the performance measures throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded. During the last several fiscal years, we have used earnings per share as our sole performance measure.

In addition, we adopted an incentive plan in October 2001 to give the employees in our nonregulated segment an opportunity to share in the success of the nonregulated operations. In fiscal 2010, we modified the award structure of the plan to reflect the different performance goals of the front and back office employees of our nonregulated operations. The front office award structure is based on a fixed percentage of the net income of our nonregulated operations that represents the available award pool for eligible employees. There is no minimum or maximum threshold for the available award pool. The back office award structure is based upon the net earnings of the nonregulated operations and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. We monitor the progress toward the achievement of the thresholds throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

9. Retirement and Post-Retirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover substantially all of our employees. We also maintain post-retirement plans that provide health care benefits to retired employees. Finally, we sponsor defined contribution plans which cover substantially all employees. These plans are discussed in further detail below.

As a rate regulated entity, we generally recover our pension costs in our rates over a period of up to 15 years. The amounts that have not yet been recognized in net periodic pension cost that have been recorded as regulatory assets are as follows:

	Defined Benefits Plans	Supplemental Executive Retirement Plans	Postretirement Plans	Total
		(In thousands)		
September 30, 2011				
Unrecognized transition obligation	$ —	$ —	$ 3,220	$ 3,220
Unrecognized prior service cost	(373)	—	(8,861)	(9,234)
Unrecognized actuarial loss	182,486	30,654	47,540	260,680
	$182,113	$30,654	$ 41,899	$254,666
September 30, 2010				
Unrecognized transition obligation	$ —	$ —	$ 4,731	$ 4,731
Unrecognized prior service cost	(842)	—	(10,311)	(11,153)
Unrecognized actuarial loss	159,539	30,753	25,694	215,986
	$158,697	$30,753	$ 20,114	$209,564

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2011, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The assets of the Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Plan is a cash balance pension plan that was established effective January 1999 and covers substantially all employees of Atmos Energy's regulated operations. Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to each participant's account at the end of each year according to a formula based on the participant's age, service and total pay (excluding incentive pay).

The Plan also provides for an additional annual allocation based upon a participant's age as of January 1, 1999 for those participants who were participants in the prior pension plans. The Plan credited this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account will be credited with interest on the employee's prior year account balance. A special grandfather benefit also applied through December 31, 2008, for participants who were at least age 50 as of January 1, 1999, and who were participants in one of the prior plans on December 31, 1998. Participants are fully vested in their account balances after three years of service and may choose to receive their account balances as a lump sum or an annuity. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Plan to new participants effective October 1, 2010. Additionally, employees participating in the Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan which was enhanced, effective January 1, 2011.

The Union Plan is a defined benefit plan that covers substantially all full-time union employees in our Mississippi Division. Under this plan, benefits are based upon years of benefit service and average final earnings. Participants vest in the plan after five years and will receive their benefit in an annuity.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974, including the funding requirements under the Pension Protection Act of 2006 (PPA). However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2011 and 2009, we contributed $0.9 million and $21.0 million in cash to the Plans to achieve a desired level of funding while maximizing the tax deductibility of this payment. In fiscal 2010, we did not make any contributions to our pension plans. Based upon market conditions subsequent to September 30, 2011, the current funded position of the plans and the new funding requirements under the PPA, we anticipate contributing between $25 million and $30 million to the Plans in fiscal 2012. Further, we will consider whether an additional voluntary contribution is prudent to maintain certain PPA funding thresholds.

We manage the Master Trust's assets with the objective of achieving a rate of return net of inflation of approximately four percent per year. We make investment decisions and evaluate performance on a medium-term horizon of at least three to five years. We also consider our current financial status when making recommendations and decisions regarding the Master Trust's assets. Finally, we strive to ensure the Master Trust's assets are appropriately invested to maintain an acceptable level of risk and meet the Master Trust's long-term asset investment policy adopted by the Board of Directors.

To achieve these objectives, we invest the Master Trust's assets in equity securities, fixed income securities, interests in commingled pension trust funds, other investment assets and cash and cash equivalents. Investments in equity securities are diversified among the market's various subsectors in an effort to diversify risk and maximize returns. Fixed income securities are invested in investment grade securities. Cash equivalents are invested in securities that either are short term (less than 180 days) or readily convertible to cash with modest risk.

The following table presents asset allocation information for the Master Trust as of September 30, 2011 and 2010.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2011	Actual Allocation September 30 2010
Domestic equities	35%-55%	40.4%	44.1%
International equities	10% - 20%	13.6%	14.4%
Fixed income	10%-30%	21.3%	19.0%
Company stock	5%-15%	13.5%	11.3%
Other assets	5%-15%	11.2%	11.2%

At September 30, 2011 and 2010, the Plan held 1,169,700 shares of our common stock, which represented 13.5 percent and 11.3 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.6 million and $1.6 million during fiscal 2011 and 2010.

Our employee pension plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our employee pension plans annually based upon a September 30 measurement date. The development of our assumptions is fully described in our significant accounting policies in Note 2. The actuarial assumptions used to determine the pension liability for the Plans were determined as of September 30, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of September 30, 2010, 2009 and 2008. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%(1)	5.52%	7.57%
Rate of compensation increase	3.50%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	7.75%	8.25%	8.25%	8.25%	8.25%

(1) The discount rate for the Pension Account Plan increased from 5.39% to 5.68% effective January 1, 2011 due to a curtailment gain recorded in the current fiscal year.

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2011 and 2010:

	2011	2010
	(In thousands)	
Accumulated benefit obligation	$ 414,489	$ 391,915
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 407,536	$ 380,045
Service cost	14,384	13,499
Interest cost	22,264	20,870
Actuarial loss	12,944	19,809
Benefits paid	(27,534)	(26,687)
Curtailments	(162)	—
Benefit obligation at end of year	429,432	407,536
Change in plan assets:		
Fair value of plan assets at beginning of year	301,708	301,146
Actual return on plan assets	5,154	27,249
Employer contributions	876	—
Benefits paid	(27,534)	(26,687)
Fair value of plan assets at end of year	280,204	301,708
Reconciliation:		
Funded status	(149,228)	(105,828)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Net amount recognized	$(149,228)	$(105,828)

Net periodic pension cost for the Plans for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2011	2010	2009
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 14,384	$ 13,499	$ 12,951
Interest cost	22,264	20,870	24,060
Expected return on assets	(24,817)	(25,280)	(24,950)
Amortization of prior service cost	(429)	(960)	(946)
Recognized actuarial loss	9,498	9,290	3,742
Curtailment gain	(40)	—	—
Net periodic pension cost	$ 20,860	$ 17,419	$ 14,857

The following table sets forth by level, within the fair value hierarchy, the Master Trust's assets at fair value as of September 30, 2011 and 2010. As required by authoritative accounting literature, assets are categorized in their entirety based on the lowest level of input that is significant to the fair value measurement. The methods used to determine fair value for the assets held by the Master Trust are fully described in Note 2.

In addition to the assets shown below, the Master Trust had net accounts receivable of $0.4 million and $0.1 million at September 30, 2011 and 2010 which materially approximates fair value due to the short-term nature of these assets.

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks	$ 94,336	$ —	$ —	$ 94,336
Money market funds	—	9,383	—	9,383
Registered investment companies	27,236	—	—	27,236
Common/collective trusts	53,309	—	—	53,309
Government securities	4,946	18,907	—	23,853
Corporate bonds	—	33,636	—	33,636
Limited partnerships	—	37,806	—	37,806
Real estate	—	—	200	200
Total investments at fair value	$179,827	$99,732	$200	$279,759

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Common stocks	$116,315	$ —	$ —	$116,315
Money market funds	—	10,013	—	10,013
Registered investment companies	32,601	—	—	32,601
Common/collective trusts	—	48,920	—	48,920
Government securities	5,548	16,296	—	21,844
Corporate bonds	—	33,987	—	33,987
Limited partnerships	—	37,691	—	37,691
Real estate	—	—	200	200
Total investments at fair value	$154,464	$146,907	$200	$301,571

The fair value of our Level 3 real estate assets was determined based on independent third party appraisals. There were no changes in the fair value of the Level 3 assets during the year ended September 30, 2011.

Supplemental Executive Benefits Plans

We have a nonqualified Supplemental Executive Benefits Plan which provides additional pension, disability and death benefits to our officers, division presidents and certain other employees of the Company who were employed on or before August 12, 1998. In addition, in August 1998, we adopted the Supplemental Executive Retirement Plan (SERP) (formerly known as the Performance-Based Supplemental Executive Benefits Plan), which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors at its discretion.

In August 2009, the Board of Directors determined that there would be no new participants in the SERP subsequent to August 5, 2009, except for any corporate officers who may be appointed to the Management Committee. The SERP is a defined benefit arrangement which provides a benefit equal to 60 percent of covered compensation under which benefits paid from the underlying qualified defined benefit plan are an offset to the benefits under the SERP. However, the Board also established a new defined benefit supplemental executive retirement plan (the 2009 SERP), effective August 5, 2009, with each participant being selected by the Board, with each such participant being either (i) a corporate officer (other than such officer who is appointed as a member of the Company's Management Committee), (ii) a division president or (iii) an employee selected in the discretion of the Board. Under the 2009 SERP, a nominal account has been established for each participant, to which the Company contributes at the end of each calendar year an amount equal to ten percent of the total of each participant's base salary and cash incentive compensation earned during each prior calendar year, beginning December 31, 2009. The benefits vest after three years of service and attainment of age 55 and earn interest credits at the same annual rate as the Company's Pension Account Plan (currently 4.69%).

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of September 30, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of September 30, 2010, 2009 and 2008. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%	5.52%	7.57%
Rate of compensation increase	3.50%	4.00%	4.00%	4.00%	4.00%

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2011 and 2010:

	2011	2010
	(In thousands)	
Accumulated benefit obligation	$ 104,363	$ 99,673
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 108,919	$ 102,747
Service cost	2,768	2,476
Interest cost	5,825	5,224
Actuarial loss	2,140	3,043
Benefits paid	(7,537)	(4,571)
Benefit obligation at end of year	112,115	108,919
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	7,537	4,571
Benefits paid	(7,537)	(4,571)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(112,115)	(108,919)
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued pension cost	$(112,115)	$(108,919)

Assets for the supplemental plans are held in separate rabbi trusts. At September 30, 2011 and 2010, assets held in the rabbi trusts consisted of available-for-sale securities of $38.3 million and $41.5 million, which are included in our fair value disclosures in Note 5.

Net periodic pension cost for the supplemental plans for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the following components:

	Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$ 2,768	$2,476	$ 1,985
Interest cost	5,825	5,224	6,056
Amortization of transition asset	—	—	—
Amortization of prior service cost	—	187	212
Recognized actuarial loss	2,239	1,999	324
Curtailment	—	—	1,645
Net periodic pension cost	$10,832	$9,886	$10,222

Supplemental Disclosures for Defined Benefit Plans with Accumulated Benefit Obligations in Excess of Plan Assets

The following summarizes key information for our defined benefit plans with accumulated benefit obligations in excess of plan assets. For fiscal 2011 and 2010 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

	Supplemental Plans	
	2011	2010
	(In thousands)	
Projected Benefit Obligation	$112,115	$108,919
Accumulated Benefit Obligation	104,363	99,673
Fair Value of Plan Assets	—	—

Estimated Future Benefit Payments

The following benefit payments for our defined benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years:

	Pension Plans	Supplemental Plans
	(In thousands)	
2012	$ 35,286	$25,116
2013	33,109	6,910
2014	31,753	4,738
2015	30,633	6,862
2016	30,648	4,622
2017-2021	146,923	43,625

Postretirement Benefits

We sponsor the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation (the Atmos Retiree Medical Plan). This plan provides medical and prescription drug protection to all qualified participants based on their date of retirement. The Atmos Retiree Medical Plan provides different levels of benefits depending on the level of coverage chosen by the participants and the terms of predecessor plans; however, we generally pay 80 percent of the projected net claims and administrative costs and participants pay the remaining 20 percent of this cost.

As of September 30, 2009, the Board of Directors approved a change to the cost sharing methodology for employees who had not met the participation requirements by that date for the Atmos Retiree Medical Plan. Starting on January 1, 2015, the contribution rates that will apply to all non-grandfathered participants will be determined using a new cost sharing methodology by which Atmos Energy will limit its contribution to a three percent cost increase in claims and administrative costs each year. If medical costs covered by the Atmos Retiree Medical Plan increase more than three percent annually, participants will be responsible for the additional cost.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute $31.5 million to our postretirement benefits plan during fiscal 2012.

We maintain a formal investment policy with respect to the assets in our postretirement benefits plan to ensure the assets funding the postretirement benefit plan are appropriately invested to maintain an acceptable level of risk. We also consider our current financial status when making recommendations and decisions regarding the postretirement benefits plan.

We currently invest the assets funding our postretirement benefit plan in diversified investment funds which consist of common stocks, preferred stocks and fixed income securities. The diversified investment funds may invest up to 75 percent of assets in common stocks and convertible securities. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2011 and 2010.

Security Class	Actual Allocation September 30 2011	2010
Diversified investment funds	96.8%	97.5%
Cash and cash equivalents	3.2%	2.5%

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our postretirement benefit plan annually based upon a September 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of September 30, 2011 and 2010 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of September 30, 2010, 2009 and 2008. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2011	2010	2011	2010	2009
Discount rate	5.05%	5.39%	5.39%	5.52%	7.57%
Expected return on plan assets	5.00%	5.00%	5.00%	5.00%	5.00%
Initial trend rate	8.00%	8.00%	8.00%	7.50%	8.00%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2018	2016	2016	2015	2015

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2011 and 2010:

	2011	2010
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 228,234	$ 209,732
Service cost	14,403	13,439
Interest cost	12,813	12,071
Plan participants' contributions	2,892	2,734
Actuarial loss	17,966	2,980
Benefits paid	(13,046)	(12,722)
Subsidy payments	432	—
Benefit obligation at end of year	263,694	228,234
Change in plan assets:		
Fair value of plan assets at beginning of year	53,033	47,646
Actual return on plan assets	(1,500)	3,551
Employer contributions	11,254	11,824
Plan participants' contributions	2,892	2,734
Benefits paid	(13,046)	(12,722)
Subsidy payments	432	—
Fair value of plan assets at end of year	53,065	53,033
Reconciliation:		
Funded status	(210,629)	(175,201)
Unrecognized transition obligation	—	—
Unrecognized prior service cost	—	—
Unrecognized net loss	—	—
Accrued postretirement cost	$(210,629)	$(175,201)

Net periodic postretirement cost for fiscal 2011, 2010 and 2009 is recorded as operating expense and included the components presented below.

	Fiscal Year Ended September 30		
	2011	2010	2009
	(In thousands)		
Components of net periodic postretirement cost:			
Service cost	$14,403	$13,439	$11,786
Interest cost	12,813	12,071	14,080
Expected return on assets	(2,727)	(2,460)	(2,292)
Amortization of transition obligation	1,511	1,511	1,511
Amortization of prior service cost	(1,450)	(1,450)	—
Recognized actuarial loss	347	374	—
Net periodic postretirement cost	$24,897	$23,485	$25,085

Assumed health care cost trend rates have a significant effect on the amounts reported for the plan. A one-percentage point change in assumed health care cost trend rates would have the following effects on the latest actuarial calculations:

	One-Percentage Point Increase	One-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 4,155	$ (3,479)
Effect on postretirement benefit obligation	$30,159	$(25,578)

We are currently recovering other postretirement benefits costs through our regulated rates under accrual accounting as prescribed by accounting principles generally accepted in the United States in substantially all of our service areas. Other postretirement benefits costs have been specifically addressed in rate orders in each jurisdiction served by our Kentucky/Mid-States Division and our Mississippi Division or have been included in a rate case and not disallowed. Management believes that this accounting method is appropriate and will continue to seek rate recovery of accrual-based expenses in its ratemaking jurisdictions that have not yet approved the recovery of these expenses.

The following table sets forth by level, within the fair value hierarchy, the Retiree Medical Plan's assets at fair value as of September 30, 2011 and 2010. The methods used to determine fair value for the assets held by the Retiree Medical Plan are fully described in Note 2.

	Assets at Fair Value as of September 30, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$1,707	$—	$ 1,707
Registered investment companies	51,358	—	—	51,358
Total investments at fair value	$51,358	$1,707	$—	$53,065

	Assets at Fair Value as of September 30, 2010			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Investments:				
Money market funds	$ —	$1,307	$—	$ 1,307
Registered investment companies	51,726	—	—	51,726
Total investments at fair value	$51,726	$1,307	$—	$53,033

Estimated Future Benefit Payments

The following benefit payments paid by us, retirees and prescription drug subsidy payments for our postretirement benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following fiscal years:

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
		(In thousands)		
2012	$31,519	$ 3,293	$—	$ 34,812
2013	13,272	3,895	—	17,167
2014	15,271	4,491	—	19,762
2015	16,789	5,026	—	21,815
2016	18,333	5,672	—	24,005
2017-2021	99,139	38,238	—	137,377

Defined Contribution Plans

As of September 30, 2011, we maintained three defined contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan), the Atmos Energy Corporation Savings Plan for MVG Union Employees (the Union 401K Plan) and the Atmos Energy Holdings, LLC 401K Profit-Sharing Plan (the AEH 401K Profit-Sharing Plan).

The Retirement Savings Plan covers substantially all employees in our regulated operations and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Effective January 1, 2007, employees automatically became participants of the Retirement Savings Plan on the date of employment. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. New participants are automatically enrolled in the Plan at a salary reduction amount of four percent of eligible compensation, from which they may opt out. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in our common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. In August 2010, the Board of Directors of Atmos Energy approved a proposal to close the Pension Account Plan to new participants effective October 1, 2010. New employees participate in our defined contribution plan, which was enhanced, effective January 1, 2011. Employees participating in the Pension Account Plan as of October 1, 2010 were allowed to make a one-time election to migrate from the Plan into our defined contribution plan, effective January 1, 2011. Under the enhanced plan, participants will receive a fixed annual contribution of four percent of eligible earnings to their Retirement Savings Plan account. Participants will continue to be eligible for company matching contributions of up to four percent of their eligible earnings and will be fully vested in the fixed annual contribution after three years of service.

The Union 401K Plan covers substantially all Mississippi Division employees who are members of the International Chemical Workers Union Council, United Food and Commercial Workers Union International (the Union) and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Employees of the Union automatically become participants of the Union 401K plan on the date of union membership. We match 50 percent of a participant's contribution in cash, limited to six percent of the participant's eligible contribution. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

Matching contributions to the Retirement Savings Plan and the Union 401K Plan are expensed as incurred and amounted to $10.2 million, $9.8 million, and $9.3 million for fiscal years 2011, 2010 and 2009. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code of 1986 and applicable regulations of the Internal Revenue Service. No discretionary contributions were made for fiscal years 2011, 2010 or 2009. At September 30, 2011 and 2010, the Retirement Savings Plan held 4.5 percent and 4.3 percent of our outstanding common stock.

The AEH 401K Profit-Sharing Plan covers substantially all AEH employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 75 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. The Company may elect to make safe harbor contributions up to four percent of the employee's salary which vest immediately. The Company may also make discretionary profit sharing contributions to the AEH 401K Profit-Sharing Plan. Participants become fully vested in the discretionary profit-sharing contributions after three years of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions. Discretionary contributions to the AEH 401K Profit-Sharing Plan are expensed as incurred and amounted to $1.3 million, $1.3 million and $1.2 million for fiscal years 2011, 2010 and 2009.

10. Details of Selected Consolidated Balance Sheet Captions

The following tables provide additional information regarding the composition of certain of our balance sheet captions.

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2011 and 2010:

	September 30	
	2011	2010
	(In thousands)	
Billed accounts receivable	$216,145	$223,129
Unbilled revenue	48,006	47,423
Other accounts receivable	16,592	15,356
Total accounts receivable	280,743	285,908
Less: allowance for doubtful accounts	(7,440)	(12,701)
Net accounts receivable	$273,303	$273,207

Other current assets

Other current assets as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Assets from risk management activities	$ 18,344	$ 20,575
Deferred gas costs	33,976	22,701
Taxes receivable	9,215	19,382
Current deferred tax asset	76,725	53,926
Prepaid expenses	22,499	24,754
Current portion of leased assets receivable	2,013	2,973
Materials and supplies	4,113	3,940
Assets held for sale	140,571	—
Other	9,015	2,744
Total	$316,471	$150,995

As discussed in Note 6, assets and liabilities related to our Missouri, Illinois and Iowa operations are classified as "assets held for sale" in other current assets and liabilities in our consolidated balance sheets at September 30, 2011.

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2011 and 2010:

	September 30	
	2011	2010
	(In thousands)	
Production plant	$ 7,412	$ 17,360
Storage plant	198,422	193,155
Transmission plant	1,126,509	1,108,398
Distribution plant	4,496,263	4,339,277
General plant	737,850	671,953
Intangible plant	41,096	54,253
	6,607,552	6,384,396
Construction in progress	209,242	157,922
	6,816,794	6,542,318
Less: accumulated depreciation and amortization	(1,668,876)	(1,749,243)
Net property, plant and equipment	$ 5,147,918	$ 4,793,075

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Marketable securities	$ 52,633	$ 41,466
Regulatory assets	278,920	254,809
Deferred financing costs	35,149	35,761
Assets from risk management activities	998	937
Other	16,093	22,403
Total	$383,793	$355,376

Other current liabilities

Other current liabilities as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Customer credit balances and deposits	$106,743	$114,215
Accrued employee costs	38,558	40,642
Deferred gas costs	8,130	43,333
Accrued interest	37,557	42,901
Liabilities from risk management activities	15,453	49,673
Taxes payable	57,853	56,616
Pension and postretirement obligations	33,036	14,815
Regulatory cost of removal accrual	35,078	30,953
Liabilities held for sale	18,445	—
Other	16,710	20,492
Total	$367,563	$413,640

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2011 and 2010 were comprised of the following accounts.

	September 30	
	2011	2010
	(In thousands)	
Postretirement obligations	$202,709	$167,899
Retirement plan obligations	236,227	207,234
Customer advances for construction	13,967	15,466
Regulatory liabilities	13,823	6,112
Asset retirement obligation	13,574	11,432
Uncertain tax positions	—	6,731
Liabilities from risk management activities	78,089	8,924
Other	6,306	6,366
Total	$564,695	$430,164

11. Earnings Per Share

Since we have non-vested share-based payments with a nonforfeitable right to dividends or dividend equivalents (referred to as participating securities) we are required to use the two-class method of computing earnings per share. The Company's non-vested restricted stock and restricted stock units, granted under the LTIP, for which vesting is predicated solely on the passage of time, are considered to be participating securities. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

Basic and diluted earnings per share for the fiscal years ended September 30 are calculated as follows:

	2011	2010	2009
	(In thousands, except per share data)		
Basic Earnings Per Share from continuing operations			
Income from continuing operations	$198,884	$198,273	$183,299
Less: Income from continuing operations allocated to participating securities	2,077	2,029	1,712
Income from continuing operations available to common shareholders	$196,807	$196,244	$181,587
Basic weighted average shares outstanding	90,201	91,852	91,117
Income from continuing operations per share — Basic	$ 2.18	$ 2.14	$ 1.99
Basic Earnings Per Share from discontinued operations			
Income from discontinued operations	$ 8,717	$ 7,566	$ 7,679
Less: Income from discontinued operations allocated to participating securities	91	77	72
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Basic weighted average shares outstanding	90,201	91,852	91,117
Income from discontinued operations per share — Basic	$ 0.10	$ 0.08	$ 0.09
Net income per share — Basic	$ 2.28	$ 2.22	$ 2.08

Diluted Earnings Per Share from continuing operations			
Income from continuing operations available to common shareholders	$196,807	$196,244	$181,587
Effect of dilutive stock options and other shares	4	5	4
Income from continuing operations available to common shareholders	$196,811	$196,249	$181,591
Basic weighted average shares outstanding	90,201	91,852	91,117
Additional dilutive stock options and other shares	451	570	503
Diluted weighted average shares outstanding	90,652	92,422	91,620
Income from continuing operations per share — Diluted	$ 2.17	$ 2.12	$ 1.98
Diluted Earnings Per Share from discontinued operations			
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Effect of dilutive stock options and other shares	—	—	—
Income from discontinued operations available to common shareholders	$ 8,626	$ 7,489	$ 7,607
Basic weighted average shares outstanding	90,201	91,852	91,117
Additional dilutive stock options and other shares	451	570	503
Diluted weighted average shares outstanding	90,652	92,422	91,620
Income from discontinued operations per share — Diluted	$ 0.10	$ 0.08	$ 0.09
Net income per share — Diluted	$ 2.27	$ 2.20	$ 2.07

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal years ended September 30, 2011 and 2010. There were approximately 70,000 out-of-the-money options excluded from the computation of diluted earnings per share for the fiscal year ended September 30, 2009.

12. Income Taxes

The components of income tax expense from continuing operations for 2011, 2010 and 2009 were as follows:

	2011	2010	2009
		(In thousands)	
Current			
Federal	$(11,204)	$(72,234)	$(37,141)
State	6,533	6,179	8,720
Deferred			
Federal	112,612	179,271	134,912
State	5,920	11,429	(8,739)
Investment tax credits	(172)	(283)	(390)
	$113,689	$124,362	$ 97,362

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2011, 2010 and 2009 are set forth below:

	2011	2010	2009
		(In thousands)	
Tax at statutory rate of 35%	$109,401	$112,922	$98,231
Common stock dividends deductible for tax reporting	(1,930)	(1,785)	(1,591)
Penalties	2,294	107	72
Settlement of uncertain tax positions	(4,950)	—	—
State taxes (net of federal benefit)	8,184	11,445	(13)
Other, net	690	1,673	663
Income tax expense	$113,689	$124,362	$97,362

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that gave rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2011 and 2010 are presented below:

	2011	2010
	(In thousands)	
Deferred tax assets:		
Accruals not currently deductible for tax purposes	$ 10,327	$ 9,182
Customer advances	5,271	5,723
Nonqualified benefit plans	43,924	43,427
Postretirement benefits	62,274	57,386
Treasury lock agreements	20,060	3,211
Unamortized investment tax credit	120	183
Tax net operating loss and credit carryforwards	95,293	63,621
Difference between book and tax on mark to market accounting	8,039	2,159
Other, net	3,529	4,559
Total deferred tax assets	248,837	189,451
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(1,108,063)	(940,914)
Pension funding	(7,533)	(14,936)
Gas cost adjustments	(13,570)	(6,473)
Cost expensed for tax purposes and capitalized for book purposes	(3,039)	(2,330)
Total deferred tax liabilities	(1,132,205)	(964,653)
Net deferred tax liabilities	$ (883,368)	$(775,202)
Deferred credits for rate regulated entities	$ 325	$ 587

At September 30, 2011, we had $10.1 million of federal alternative minimum tax credit carryforwards, $75.2 million of federal net operating loss carryforwards and $9.9 million of state net operating loss carryforwards. The alternative minimum tax credit carryforwards do not expire. The federal net operating loss carryforwards are available to offset taxable income and will begin to expire in 2029. Depending on the jurisdiction in which the state net operating loss was generated, the state net operating loss carryforwards will begin to expire between 2016 and 2029.

At September 30, 2010, we had accrued liabilities associated with uncertain tax positions totaling $6.7 million. During the fiscal year ended September 30, 2011, the IRS completed its audit of fiscal years 2005-2007. All uncertain tax positions were effectively settled upon completion of the audit. As a result of the settlement, we reduced our unrecognized tax benefits by $6.7 million in the second quarter of fiscal 2011. Income tax expense was reduced by $5.0 million in the second quarter due to the realization of the tax positions which were previously uncertain. As of September 30, 2011, we had no liabilities associated with uncertain tax positions.

We recognize accrued interest related to unrecognized tax benefits as a component of interest expense. We recognize penalties related to unrecognized tax benefits as a component of miscellaneous income (expense) in accordance with regulatory requirements. We recognized a tax expense of $0.01 million, $0.5 million and $0.1 million related to penalty and interest expenses during the fiscal years ended September 30, 2011, 2010 and 2009.

We file income tax returns in the U.S. federal jurisdiction as well as in various states where we have operations. We have concluded substantially all U.S. federal income tax matters through fiscal year 2007.

13. Commitments and Contingencies

Litigation

Since April 2009, Atmos Energy and two subsidiaries of AEH, AEM and Atmos Gathering Company, LLC (AGC) (collectively, the Atmos Entities), have been involved in a lawsuit filed in the Circuit Court of Edmonson County, Kentucky related to our Park City Gathering Project. The dispute which gave rise to the litigation involves the amount of royalties due from a third party producer to landowners (who own the mineral rights) for natural gas produced from the landowners' properties. The third party producer was operating pursuant to leases between the landowners and certain investors/working interest owners. The third party producer filed a petition in bankruptcy, which was subsequently dismissed due to the lack of meaningful assets to reorganize or liquidate.

Although certain Atmos Energy companies entered into contracts with the third party producer to gather, treat and ultimately sell natural gas produced from the landowners' properties, no Atmos Energy company had a contractual relationship with the landowners or the investors/working interest owners. After the lawsuit was filed, the landowners were successful in terminating for non-payment of royalties the leases related to the production of natural gas from their properties. Subsequent to termination, the investors/working interest owners under such leases filed additional claims against us for the termination of the leases.

During the trial, the landowners and the investors/working interest owners requested an award of compensatory damages plus punitive damages against us. On December 17, 2010, the jury returned a verdict in favor of the landowners and investor/working interest owners and awarded compensatory damages of $3.8 million and punitive damages of $27.5 million payable by Atmos Energy and the two AEH subsidiaries.

A hearing was held on February 28, 2011 to hear a number of motions, including a motion to dismiss the jury verdict and a motion for a new trial. The motions to dismiss the jury verdict and for a new trial were denied. However, the total punitive damages award was reduced from $27.5 million to $24.7 million. On March 30, 2011, we filed a notice of appeal of this ruling. We strongly believe that the trial court erred in not granting our motion to dismiss the lawsuit prior to trial and that the verdict is unsupported by law. After consultation with counsel, we believe that it is probable that any judgment based on this verdict will be overturned on appeal.

In addition, in a related development, on July 12, 2011, the Atmos Entities filed a lawsuit in the United States District Court, Western District of Kentucky against the third party producer and its affiliates to recover all costs, including attorneys' fees, incurred by the Atmos Entities, which are associated with the defense and appeal of the case discussed above as well as for all damages awarded to the plaintiffs in such case against the Atmos Entities. The total amount of damages being claimed in the lawsuit is "open-ended" since the appellate process and related costs are ongoing. This lawsuit is based upon the indemnification provisions agreed to by the third party producer in favor of Atmos Gathering that are contained in an agreement entered into between Atmos Gathering and the third party producer in May 2009.

We have accrued what we believe is an adequate amount for the anticipated resolution of this matter; however, the amount accrued is less than the amount of the verdict. The Company does not have insurance coverage that could mitigate any losses that may arise from the resolution of this matter; however, we believe that the final outcome will not have a material adverse effect on our financial condition, results of operations or cash flows.

We are a party to other litigation and claims that have arisen in the ordinary course of our business. While the results of such litigation and claims cannot be predicted with certainty, we believe the final outcome of such litigation and claims will not have a material adverse effect on our financial condition, results of operations or cash flows.

Environmental Matters

Former Manufactured Gas Plant Sites

We are the owner or previous owner of former manufactured gas plant sites in Johnson City, Tennessee, Keokuk, Iowa and Owensboro, Kentucky, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. We have taken removal actions with respect to the sites that have been approved by the applicable regulatory authorities in Tennessee, Iowa, Kentucky and the United States Environmental Protection Agency.

We are a party to other environmental matters and claims that have arisen in the ordinary course of our business. While the ultimate results of response actions to these environmental matters and claims cannot be predicted with certainty, we believe the final outcome of such response actions will not have a material adverse effect on our financial condition, results of operations or cash flows because we believe that the expenditures related to such response actions will either be recovered through rates, shared with other parties or are adequately covered by insurance.

Purchase Commitments

AEH has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2011, AEH was committed to purchase 103.3 Bcf within one year, 46.4 Bcf within one to three years and 0.9 Bcf after three years under indexed contracts. AEH is committed to purchase 4.2 Bcf within one year and 0.3 Bcf within one to three years under fixed price contracts with prices ranging from $3.49 to $6.36 per Mcf. Purchases under these contracts totaled $1,498.6 million, $1,562.8 million and $1,484.5 million for 2011, 2010 and 2009.

Our natural gas distribution divisions, except for our Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market and fixed prices. The estimated commitments under these contracts as of September 30, 2011 are as follows (in thousands):

2012	$274,985
2013	102,959
2014	82,235
2015	—
2016	—
Thereafter	—
	$460,179

Our nonregulated segment maintains long-term contracts related to storage and transportation. The estimated contractual demand fees for contracted storage and transportation under these contracts as of September 30, 2011 are as follows (in thousands):

2012	$25,362
2013	16,711
2014	9,988
2015	4,130
2016	278
Thereafter	165
	$56,634

Other Contingencies

In December 2007, the Company received data requests from the Division of Investigations of the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") in connection with its investigation into possible violations of the Commission's posting and competitive bidding regulations for pre-arranged released firm capacity on natural gas pipelines.

Since that time, we have fully cooperated with FERC during this investigation. In August 2011, the FERC issued a Notice of Alleged Violations stating that it preliminarily determined that Atmos Energy Corporation and its subsidiaries, Atmos Energy Marketing, LLC (AEM) and Trans Louisiana Gas Pipeline, Inc. (TLGP) violated Sections 284.8(h)(2) and 1c.1 of the Commission's regulations through flipping and AEM violated the Commission's shipper-must-have-title requirement and the associated FERC gas tariffs of various pipelines.

The Company and FERC are currently involved in settlement discussions. We have accrued what we believe is an adequate amount for the anticipated resolution of this matter.

We have been replacing certain steel service lines in our Mid-Tex Division since our acquisition of the natural gas distribution system in 2004. Since early 2010, we have been discussing the financial and operational details of an accelerated steel service line replacement program with representatives of 440 municipalities served by our Mid-Tex Division. As previously discussed in Note 12 to the consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended September 30, 2010, all of the cities in our Mid-Tex Division have agreed to a program of installing 100,000 replacements during the next fiscal year, with approved recovery of the associated return, depreciation and taxes. Under the terms of the agreement, the accelerated replacement program commenced in the first quarter of fiscal 2011, replacing

35,852 lines for a cost of $49.7 million as of September 30, 2011. The program is progressing on schedule for completion in September 2012.

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act calls for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act, which we expect will provide additional clarity regarding the extent of the impact of this legislation on us. The costs of participating in financial markets for hedging certain risks inherent in our business may be increased as a result of the new legislation. We may also incur additional costs associated with compliance with new regulations and anticipate additional reporting and disclosure obligations.

14. Leases

Leasing Operations

A subsidiary of AEH has constructed electric peaking power-generating plants and associated facilities and entered into agreements to either lease or sell these plants. We completed a sales-type lease transaction for one distributed electric generation plant in 2001 and a second sales-type lease transaction in 2003. In connection with these lease transactions, as of September 30, 2011 and 2010, we had receivables of $2.0 million and $7.8 million and recognized income of $0.5 million, $0.9 million and $1.2 million for fiscal years 2011, 2010 and 2009. The future minimum lease payments to be received for each of the five succeeding fiscal years are as follows:

	Minimum Lease Receipts
	(In thousands)
2012	$2,013
Thereafter	—
Total minimum lease receipts	$2,013

Capital and Operating Leases

We have entered into non-cancelable operating leases for office and warehouse space used in our operations. The remaining lease terms range from one to 21 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $1.3 and $1.3 million at September 30, 2011 and 2010. Accumulated depreciation for these capital leases totaled $0.9 and $0.8 million at September 30, 2011 and 2010. Depreciation expense for these assets is included in consolidated depreciation expense on the consolidated statement of income.

The related future minimum lease payments at September 30, 2011 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2012	$ 186	$ 17,718
2013	186	16,846
2014	186	16,519
2015	186	15,455
2016	186	14,921
Thereafter	264	118,108
Total minimum lease payments	1,194	$199,567
Less amount representing interest	406	
Present value of net minimum lease payments	$ 788	

Consolidated lease and rental expense amounted to $19.1 million, $16.0 million and $13.6 million for fiscal 2011, 2010 and 2009.

15. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated with trade accounts receivable for the natural gas distribution segment is mitigated by the large number of individual customers and diversity in our customer base. The credit risk for our other segments is not significant.

Customer diversification also helps mitigate AEM's exposure to credit risk. AEM maintains credit policies with respect to its counterparties that it believes minimizes overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements, primarily consisting of letters of credit, and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We believe, based on our credit policies and our provisions for credit losses as of September 30, 2011, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any single counterparty.

AEM's estimated credit exposure is monitored in terms of the percentage of its customers, including affiliate customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM's credit department, but are primarily based on external ratings provided by Moody's Investors Service Inc. (Moody's) and/or Standard & Poor's Corporation (S&P). For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. Customers who have a non-investment grade but provide either a letter of credit or prepay their monthly invoice have been included as investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2011 and 2010.

	September 30, 2011	September 30, 2010
Investment grade	54%	58%
Non-investment grade	46%	42%
Total	100%	100%

The following table presents our financial instrument counterparty credit exposure by operating segment based upon the unrealized fair value of our financial instruments that represent assets as of September 30, 2011. Investment grade counterparties have minimum credit ratings of BBB-, assigned by S&P; or Baa3, assigned by Moody's. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	Natural Gas Distribution Segment[1]	Nonregulated Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$—	$ 16	$ 16
Non-investment grade counterparties	—	1,081	1,081
	$—	$1,097	$1,097

(1) Counterparty risk for our natural gas distribution segment is minimized because hedging gains and losses are passed through to our customers.

16. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for fiscal 2011, 2010 and 2009 are presented below.

	2011	2010	2009
		(In thousands)	
Cash paid for interest	$157,976	$161,925	$163,554
Cash received for income taxes	$ (8,329)	$(63,677)	$(36,405)

There were no significant noncash investing and financing transactions during fiscal 2011, 2010 and 2009. All cash flows and noncash activities related to our commodity financial instruments are considered as operating activities.

17. Segment Information

Atmos Energy Corporation and its subsidiaries are engaged primarily in the regulated natural gas distribution, transmission and storage business as well as other nonregulated businesses. We distribute natural gas through sales and transportation arrangements to over three million residential, commercial, public authority and industrial customers through our six regulated natural gas distribution divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonregulated businesses, we primarily provide natural gas management and marketing services to municipalities, other local distribution companies and industrial customers primarily in the Midwest and Southeast. Additionally, we provide natural gas transportation and storage services to certain of our natural gas distribution operations and to third parties.

Through November 30, 2010, our operations were divided into four segments:

- The *natural gas distribution segment*, which included our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, which included the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *natural gas marketing segment*, which included a variety of nonregulated natural gas management services.
- The *pipeline, storage and other segment*, which included our nonregulated natural gas gathering transmission and storage services.

As a result of the appointment of a new CEO effective October 1, 2010, during the first quarter of fiscal 2011, we revised the information used by the chief operating decision maker to manage the Company. As a result of this change, effective December 1, 2010, we began dividing our operations into the following three segments:

- The *natural gas distribution segment*, remains unchanged and includes our regulated natural gas distribution and related sales operations.
- The *regulated transmission and storage segment*, remains unchanged and includes the regulated pipeline and storage operations of our Atmos Pipeline — Texas Division.
- The *nonregulated segment*, is comprised of our nonregulated natural gas management, nonregulated natural gas transmission, storage and other services which were previously reported in the natural gas marketing and pipeline, storage and other segments.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our natural gas distribution segment operations are geographically dispersed, they are reported as a single segment as each natural gas distribution division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

Summarized income statements and capital expenditures by segment are shown in the following tables. Prior-year amounts have been restated to reflect the new operating segments.

	Year Ended September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,530,980	$ 87,141	$1,729,513	$ —	$4,347,634
Intersegment revenues	883	132,232	295,380	(428,495)	—
	2,531,863	219,373	2,024,893	(428,495)	4,347,634
Purchased gas cost	1,487,499	—	1,959,893	(426,999)	3,020,393
Gross profit	1,044,364	219,373	65,000	(1,496)	1,327,241
Operating expenses					
Operation and maintenance	348,083	70,401	32,308	(1,502)	449,290
Depreciation and amortization	196,909	25,997	4,193	—	227,099
Taxes, other than income	161,371	14,700	2,612	—	178,683
Asset impairments	—	—	30,270	—	30,270
Total operating expenses	706,363	111,098	69,383	(1,502)	885,342
Operating income (loss)	338,001	108,275	(4,383)	6	441,899
Miscellaneous income	16,557	4,715	657	(430)	21,499
Interest charges	115,802	31,432	4,015	(424)	150,825
Income (loss) from continuing operations before income taxes	238,756	81,558	(7,741)	—	312,573
Income tax expense (benefit)	84,755	29,143	(209)	—	113,689
Income (loss) from continuing operations	154,001	52,415	(7,532)	—	198,884
Income from discontinued operations, net of tax	8,717	—	—	—	8,717
Net income (loss)	$ 162,718	$ 52,415	$ (7,532)	$ —	$ 207,601
Capital expenditures	$ 496,899	$118,452	$ 7,614	$ —	$ 622,965

	Year Ended September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,841,768	$ 97,023	$1,781,044	$ —	$4,719,835
Intersegment revenues	870	105,990	365,614	(472,474)	—
	2,842,638	203,013	2,146,658	(472,474)	4,719,835
Purchased gas cost	1,820,627	—	2,032,567	(470,864)	3,382,330
Gross profit	1,022,011	203,013	114,091	(1,610)	1,337,505
Operating expenses					
Operation and maintenance	355,357	72,249	34,517	(1,610)	460,513
Depreciation and amortization	185,147	21,368	5,074	—	211,589
Taxes, other than income	171,338	12,358	4,556	—	188,252
Total operating expenses	711,842	105,975	44,147	(1,610)	860,354
Operating income	310,169	97,038	69,944	—	477,151
Miscellaneous income (expense)	1,567	135	3,859	(5,717)	(156)
Interest charges	118,319	31,174	10,584	(5,717)	154,360
Income from continuing operations before income taxes	193,417	65,999	63,219	—	322,635
Income tax expense	75,034	24,513	24,815	—	124,362
Income from continuing operations	118,383	41,486	38,404	—	198,273
Income from discontinued operations, net of tax	7,566	—	—	—	7,566
Net income	$ 125,949	$ 41,486	$ 38,404	$ —	$ 205,839
Capital expenditures	$ 437,815	$ 95,835	$ 8,986	$ —	$ 542,636

	Year Ended September 30, 2009				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
Operating revenues from external parties	$2,883,997	$119,427	$1,865,687	$ —	$4,869,111
Intersegment revenues	799	90,231	418,301	(509,331)	—
	2,884,796	209,658	2,283,988	(509,331)	4,869,111
Purchased gas cost	1,887,192	—	2,169,880	(507,639)	3,549,433
Gross profit	997,604	209,658	114,108	(1,692)	1,319,678
Operating expenses					
Operation and maintenance	361,123	85,249	41,368	(2,036)	485,704
Depreciation and amortization	187,050	20,413	4,521	—	211,984
Taxes, other than income	166,854	10,231	3,157	—	180,242
Asset impairments	4,599	602	181	—	5,382
Total operating expenses	719,626	116,495	49,227	(2,036)	883,312
Operating income	277,978	93,163	64,881	344	436,366
Miscellaneous income (expense)	6,002	1,433	6,399	(16,901)	(3,067)
Interest charges	123,863	30,982	14,350	(16,557)	152,638
Income from continuing operations before income taxes	160,117	63,614	56,930	—	280,661
Income tax expense	50,989	22,558	23,815	—	97,362
Income from continuing operations	109,128	41,056	33,115	—	183,299
Income from discontinued operations, net of tax	7,679	—	—	—	7,679
Net income	$ 116,807	$ 41,056	$ 33,115	$ —	$ 190,978
Capital expenditures	$ 379,500	$108,332	$ 21,662	$ —	$ 509,494

The following table summarizes our revenues by products and services for the fiscal year ended September 30. Prior-year amounts have been restated to reflect the new operating segments.

	2011	2010	2009
		(In thousands)	
Natural gas distribution revenues:			
Gas sales revenues:			
Residential	$1,570,723	$1,784,051	$1,768,082
Commercial	698,366	787,433	807,109
Industrial	106,569	110,280	132,487
Public authority and other	69,176	70,402	88,972
Total gas sales revenues	2,444,834	2,752,166	2,796,650
Transportation revenues	59,547	58,511	56,162
Other gas revenues	26,599	31,091	31,185
Total natural gas distribution revenues	2,530,980	2,841,768	2,883,997
Regulated transmission and storage revenues	87,141	97,023	119,427
Nonregulated revenues	1,729,513	1,781,044	1,865,687
Total operating revenues	$4,347,634	$4,719,835	$4,869,111

Balance sheet information at September 30, 2011 and 2010 by segment is presented in the following tables. Prior-year amounts have been restated to reflect the new operating segments.

	September 30, 2011				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$4,248,198	$ 838,302	$ 61,418	$ —	$5,147,918
Investment in subsidiaries	670,993	—	(2,096)	(668,897)	—
Current assets					
Cash and cash equivalents	24,646	—	106,773	—	131,419
Assets from risk management activities	843	—	17,501	—	18,344
Other current assets	655,716	15,413	386,215	(196,154)	861,190
Intercompany receivables	569,898	—	—	(569,898)	—
Total current assets	1,251,103	15,413	510,489	(766,052)	1,010,953
Intangible assets	—	—	207	—	207
Goodwill	572,908	132,381	34,711	—	740,000
Noncurrent assets from risk management activities	998	—	—	—	998
Deferred charges and other assets	353,960	18,028	10,807	—	382,795
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,255,421	$ 265,102	$405,891	$ (670,993)	$2,255,421
Long-term debt	2,205,986	—	131	—	2,206,117
Total capitalization	4,461,407	265,102	406,022	(670,993)	4,461,538
Current liabilities					
Current maturities of long-term debt	2,303	—	131	—	2,434
Short-term debt	387,691	—	—	(181,295)	206,396
Liabilities from risk management activities	11,916	—	3,537	—	15,453
Other current liabilities	474,783	10,369	170,926	(12,763)	643,315
Intercompany payables	—	543,084	26,814	(569,898)	—
Total current liabilities	876,693	553,453	201,408	(763,956)	867,598
Deferred income taxes	789,649	173,351	(2,907)	—	960,093
Noncurrent liabilities from risk management activities	67,862	—	10,227	—	78,089
Regulatory cost of removal obligation	428,947	—	—	—	428,947
Deferred credits and other liabilities	473,602	12,218	786	—	486,606
	$7,098,160	$1,004,124	$615,536	$(1,434,949)	$7,282,871

	September 30, 2010				
	Natural Gas Distribution	Regulated Transmission and Storage	Nonregulated	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Property, plant and equipment, net	$3,959,112	$748,947	$ 85,016	$ —	$4,793,075
Investment in subsidiaries	620,863	—	(2,096)	(618,767)	—
Current assets					
Cash and cash equivalents	31,952	—	100,000	—	131,952
Assets from risk management activities	2,219	—	18,356	—	20,575
Other current assets	528,655	19,504	325,348	(150,842)	722,665
Intercompany receivables	546,313	—	—	(546,313)	—
Total current assets	1,109,139	19,504	443,704	(697,155)	875,192
Intangible assets	—	—	834	—	834
Goodwill	572,262	132,341	34,711	—	739,314
Noncurrent assets from risk management activities	47	—	890	—	937
Deferred charges and other assets	324,707	13,037	16,695	—	354,439
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791
CAPITALIZATION AND LIABILITIES					
Shareholders' equity	$2,178,348	$212,687	$408,176	$ (620,863)	$2,178,348
Long-term debt	1,809,289	—	262	—	1,809,551
Total capitalization	3,987,637	212,687	408,438	(620,863)	3,987,899
Current liabilities					
Current maturities of long-term debt	360,000	—	131	—	360,131
Short-term debt	258,488	—	—	(132,388)	126,100
Liabilities from risk management activities	48,942	—	731	—	49,673
Other current liabilities	473,076	10,949	162,508	(16,358)	630,175
Intercompany payables	—	543,007	3,306	(546,313)	—
Total current liabilities	1,140,506	553,956	166,676	(695,059)	1,166,079
Deferred income taxes	691,126	142,337	(4,335)	—	829,128
Noncurrent liabilities from risk management activities	2,924	—	6,000	—	8,924
Regulatory cost of removal obligation	350,521	—	—	—	350,521
Deferred credits and other liabilities	413,416	4,849	2,975	—	421,240
	$6,586,130	$913,829	$579,754	$(1,315,922)	$6,763,791

18. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. Prior-period amounts have been restated to reflect continuing operations. The sum of net income per share by quarter may not equal the net income per share for the fiscal year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2011:				
Operating revenues				
Natural gas distribution	$ 703,462[1]	$1,077,414[2]	$ 407,031	$ 343,956
Regulated transmission and storage	49,007	54,976	53,570	61,820
Nonregulated	475,640	583,531	491,285	474,437
Intersegment eliminations	(94,847)	(134,424)	(108,271)	(90,953)
	1,133,262	1,581,497	843,615	789,260
Gross profit	364,724[1]	453,668[2]	266,805	242,044
Operating income	155,289[1]	211,199[2]	34,078	41,333
Income (loss) from continuing operations	71,100	128,160	(1,474)	1,098
Income from discontinued operations	2,897	4,049	908	863
Net income (loss)	73,997	132,209	(566)	1,961
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.78	$ 1.41	$ (0.02)	$ 0.01
Income per share from discontinued operations	$ 0.03	$ 0.04	$ 0.01	$ 0.01
Net income (loss) per share — basic	$ 0.81	$ 1.45	$ (0.01)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.78	$ 1.41	$ (0.02)	$ 0.01
Income per share from discontinued operations	$ 0.03	$ 0.04	$ 0.01	$ 0.01
Net income (loss) per share — diluted	$ 0.81	$ 1.45	$ (0.01)	$ 0.02

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2010:				
Operating revenues				
Natural gas distribution	$ 781,841[3]	$1,333,872[4]	$ 396,319	$ 330,606[5]
Regulated transmission and storage	46,860	55,181	44,957	56,015
Nonregulated	548,016	677,032	427,405	494,205
Intersegment eliminations	(104,918)	(157,935)	(107,376)	(102,245)
	1,271,799	1,908,150	761,305	778,581
Gross profit	403,003[3]	445,444[4]	247,666	241,392[5]
Operating income	186,598[3]	219,757[4]	32,259	38,537[5]
Income (loss) from continuing operations	90,975	111,283	(4,229)	244
Income from discontinued operations	2,355	2,843	1,075	1,293
Net income (loss)	93,330	114,126	(3,154)	1,537
Basic earnings per share				
Income (loss) per share from continuing operations	$ 0.97	$ 1.19	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.03	0.03	$ 0.01	$ 0.02
Net income (loss) per share — basic	$ 1.00	$ 1.22	$ (0.03)	$ 0.02
Diluted earnings per share				
Income (loss) per share from continuing operations	$ 0.97	$ 1.19	$ (0.04)	$ —
Income per share from discontinued operations	$ 0.03	$ 0.03	$ 0.01	$ 0.02
Net income (loss) per share — diluted	$ 1.00	$ 1.22	$ (0.03)	$ 0.02

(1) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $23.7 million, $8.8 million and $4.8 million.

(2) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $35.8 million, $11.2 million and $6.7 million.

(3) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $21.1 million, $7.8 million and $4.0 million.

(4) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $32.1 million, $8.9 million and $4.8 million.

(5) Operating revenues for natural gas distribution, gross profit and operating income are shown net of discontinued operations of $7.7 million, $5.2 million and $1.7 million.

ITEM 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.***

None.

ITEM 9A. ***Controls and Procedures.***

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, of the effectiveness of the Company's disclosure controls and procedures, as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of September 30, 2011 to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified by the SEC's rules and forms, including a reasonable level of assurance that such information is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2011, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Ernst & Young LLP has issued its report on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ KIM R. COCKLIN
Kim R. Cocklin
President and Chief Executive Officer

/s/ FRED E. MEISENHEIMER
Fred E. Meisenheimer
Senior Vice President and
Chief Financial Officer

November 22, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Atmos Energy Corporation

We have audited Atmos Energy Corporation's internal control over financial reporting as of September 30, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Atmos Energy Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Atmos Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of September 30, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of September 30, 2011 and 2010, and the related statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2011 of Atmos Energy Corporation and our report dated November 22, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas
November 22, 2011

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fourth quarter of the fiscal year ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. *Other Information.*

Not applicable.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance.*

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012. Information regarding executive officers is reported below:

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2011, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

Name	Age	Years of Service	Office Currently Held
Robert W. Best	64	14	Executive Chairman of the Board
Kim R. Cocklin	60	5	President and Chief Executive Officer
Louis P. Gregory	56	11	Senior Vice President and General Counsel
Michael E. Haefner	51	3	Senior Vice President, Human Resources
Fred E. Meisenheimer	67	11	Senior Vice President and Chief Financial Officer

Robert W. Best was named Executive Chairman of the Board on October 1, 2010. From March 1997 through September 2008, Mr. Best served the Company as Chairman of the Board, President and Chief Executive Officer. From October 1, 2008 through September 30, 2010, Mr. Best continued to serve the Company as Chairman of the Board and Chief Executive Officer.

Kim R. Cocklin was named President and Chief Executive Officer effective October 1, 2010. Mr. Cocklin joined the Company in June 2006 and served as President and Chief Operating Officer of the Company from October 1, 2008 through September 30, 2010, after having served as Senior Vice President, Regulated Operations from October 2006 through September 2008. Mr. Cocklin was Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 through May 2006. Mr. Cocklin was appointed to the Board of Directors on November 10, 2009.

Louis P. Gregory was named Senior Vice President and General Counsel in September 2000.

Michael E. Haefner joined the Company in June 2008 as Senior Vice President, Human Resources. Prior to joining the Company, Mr. Haefner was a self-employed consultant and founder and president of Perform for Life, LLC from May 2007 to May 2008. Mr. Haefner previously served for 10 years as the Senior Vice President, Human Resources, of Sabre Holding Corporation, the parent company of Sabre Airline Solutions, Sabre Travel Network and Travelocity.

Fred E. Meisenheimer was named Senior Vice President and Chief Financial Officer in February 2009. Mr. Meisenheimer previously served the Company as Vice President and Controller from July 2000 through

May 2009, interim Chief Financial Officer in January 2009 and Treasurer from November 2009 through February 2011.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of Directors is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com* under "Corporate Governance." In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance."

ITEM 11. *Executive Compensation.*

Information on executive compensation is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.*

Security ownership of certain beneficial owners and of management is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012. Information concerning our equity compensation plans is provided in Part II, Item 5, "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities", of this Annual Report on Form 10-K.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence.*

Information on certain relationships and related transactions as well as director independence is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012.

ITEM 14. *Principal Accountant Fees and Services.*

Information on our principal accountant's fees and services is incorporated herein by reference to the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 8, 2012.

PART IV

ITEM 15. *Exhibits and Financial Statement Schedules.*

(a) 1. and 2. *Financial statements and financial statement schedules.*

The financial statements and financial statement schedule listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K.

3. *Exhibits*

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K. The exhibits numbered 10.6(a) through 10.14 are management contracts or compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ FRED E. MEISENHEIMER

Fred E. Meisenheimer
Senior Vice President and Chief Financial Officer

Date: November 22, 2011

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Kim R. Cocklin and Fred. E. Meisenheimer, or either of them acting alone or together, as his true and lawful attorney-in-fact and agent with full power to act alone, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ KIM R. COCKLIN Kim R. Cocklin	President, Chief Executive Officer and Director	November 22, 2011
/s/ FRED E. MEISENHEIMER Fred E. Meisenheimer	Senior Vice President and Chief Financial Officer	November 22, 2011
/s/ CHRISTOPHER T. FORSYTHE Christopher T. Forsythe	Vice President and Controller (Principal Accounting Officer)	November 22, 2011
/s/ ROBERT W. BEST Robert W. Best	Executive Chairman of the Board	November 22, 2011
/s/ RICHARD W. DOUGLAS Richard W. Douglas	Director	November 22, 2011
/s/ RUBEN E. ESQUIVEL Ruben E. Esquivel	Director	November 22, 2011
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 22, 2011
/s/ ROBERT C. GRABLE Robert C. Grable	Director	November 22, 2011
/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 22, 2011
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 22, 2011
/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 22, 2011
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 22, 2011
/s/ RICHARD WARE II Richard Ware II	Director	November 22, 2011

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2011

	Balance at beginning of period	Additions: Charged to Cost & Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
		(In thousands)			
2011					
Allowance for doubtful accounts	$12,701	$2,201	$—	$ 7,462[1]	$ 7,440
2010					
Allowance for doubtful accounts	$11,478	$7,694	$—	$ 6,471[1]	$12,701
2009					
Allowance for doubtful accounts	$15,301	$7,769	$—	$11,592[1]	$11,478

(1) Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Acquisition	
2.1	Asset Purchase Agreement by and between Atmos Energy Corporation as Seller and Liberty Energy (Midstates) Corp. as Buyer, dated as of May 12, 2011	Exhibit 2.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Restated Articles of Incorporation of Atmos Energy Corporation — Texas (As Amended Effective February 3, 2010)	Exhibit 3.1 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.2	Restated Articles of Incorporation of Atmos Energy Corporation — Virginia (As Amended Effective February 3, 2010)	Exhibit 3.2 to Form 10-Q dated March 31, 2010 (File No. 1-10042)
3.3	Amended and Restated Bylaws of Atmos Energy Corporation (as of February 3, 2010)	Exhibit 3.2 of Form 8-K dated February 3, 2010 (File No. 1-10042)
	Instruments Defining Rights of Security Holders	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit 4.1 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
4.2	Indenture dated as of November 15, 1995 between United Cities Gas Company and Bank of America Illinois, Trustee	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.3	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.4	Indenture dated as of May 22, 2001 between Atmos Energy Corporation and SunTrust Bank, Trustee	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.5	Indenture dated as of June 14, 2007, between Atmos Energy Corporation and U.S. Bank National Association, Trustee	Exhibit 4.1 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.6	Indenture dated as of March 23, 2009 between Atmos Energy Corporation and U.S. Bank National Corporation, Trustee	Exhibit 4.1 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(a)	Debenture Certificate for the 6¾% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.7(b)	Global Security for the 5⅛% Senior Notes due 2013	Exhibit 10(2)(c) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(c)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(d)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for fiscal year ended September 30, 2004 (File No. 1-10042)
4.7(e)	Global Security for the 6.35% Senior Notes due 2017	Exhibit 4.2 to Form 8-K dated June 11, 2007 (File No. 1-10042)
4.7(f)	Global Security for the 8.50% Senior Notes due 2019	Exhibit 4.2 to Form 8-K dated March 26, 2009 (File No. 1-10042)
4.7(g)	Global Security for the 5.5% Senior Notes due 2041	Exhibit 4.2 to Form 8-K dated June 10, 2011 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Material Contracts	
10.1	Pipeline Construction and Operating Agreement, dated November 30, 2005, by and between Atmos-Pipeline Texas, a division of Atmos Energy Corporation, a Texas and Virginia corporation and Energy Transfer Fuel, LP, a Delaware limited partnership	Exhibit 10.1 to Form 8-K dated November 30, 2005 (File No. 1-10042)
10.2	Revolving Credit Agreement, dated as of May 2, 2011 among Atmos Energy Corporation, the Lenders from time to time parties thereto, The Royal Bank of Scotland plc as Administrative Agent, Crédit Agricole Corporate and Investment Bank as Syndication Agent, Bank of America, N.A., U.S. Bank National Association and Wells Fargo Bank, N.A. as Co-Documentation Agents	Exhibit 10.1 to Form 8-K dated May 2, 2011 (File No. 1-10042)
10.3(a)	Fifth Amended and Restated Credit Agreement, dated as of December 8, 2010, among Atmos Energy Marketing, LLC, a Delaware limited liability company, BNP Paribas, a bank organized under the laws of France, as administrative agent, collateral agent, as an issuing bank, a swing line bank and a bank; Société Générale as co-syndication agent, an issuing bank and a bank and The Royal Bank of Scotland plc, as co-syndication agent and a bank; and Natixis, New York Branch, Crédit Agricole Corporate and Investment Bank, and Cooperatieve Centrale Raiffeisen-Boerenleenbank B.A. as co-documentation agents and the other financial institutions that become parties thereto	Exhibit 10.1 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.3(b)	Third Amended and Restated Intercreditor Agreement, dated as of December 8, 2010, (as amended, supplemented and otherwise modified from time to time, the "Agreement"), among BNP Paribas, a bank organized under the laws of France, in its capacity as Collateral Agent (together with its successors and assigns in such capacity, the "Agent") for the Banks thereinafter referred to, and each bank and other financial institution which is now or hereafter a party to the Agreement in its capacity as a Bank and, as applicable, as a Swap Bank (collectively, the "Swap Banks") and/or a Physical Trade Bank (collectively, the "Physical Trade Banks")	Exhibit 10.2 to Form 8-K dated December 8, 2010 (File No. 1-10042)
10.4(a)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Master Confirmation dated July 1, 2010	Exhibit 10.6(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.4(b)	Accelerated Share Buyback Agreement with Goldman, Sachs & Co. — Supplemental Confirmation dated July 1, 2010	Exhibit 10.6(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.5	Guaranty of Algonquin Power & Utilities Corp. dated May 12, 2011	Exhibit 10.1 to Form 8-K dated May 12, 2011 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.6(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.6(b)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	Exhibit 10.7(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.7(a)*	Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.7(b)*	Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.8(a)*	Description of Financial and Estate Planning Program	Exhibit 10.25(b) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.8(b)*	Description of Sporting Events Program	Exhibit 10.26(c) to Form 10-K for fiscal year ended September 30, 1993 (File No. 1-10042)
10.9(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 7, 2007	Exhibit 10.8(a) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.9(b)*	Atmos Energy Corporation Supplemental Executive Retirement Plan (As Amended and Restated, Effective as of November 12, 2009)	Exhibit 10.10(b) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(c)*	Atmos Energy Corporation Account Balance Supplemental Executive Retirement Plan, Effective Date August 5, 2009	Exhibit 10.10(c) to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.9(d)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.9(e)*	Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan	Exhibit 10.3 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.10(a)*	Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994	Exhibit 10.28(f) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.10(b)*	Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001	Exhibit 10.28(g) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.10(c)*	Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042)
10.11*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors, Amended and Restated as of January 1, 2010	Exhibit 10.12 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)
10.12*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan, Amended and Restated as of October 1, 2009	Exhibit 10.13 to Form 10-K for fiscal year ended September 30, 2010 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.13(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 10, 2011)	Exhibit 99.1 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.13(b)*	Form of Non-Qualified Stock Option Agreement under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.16(b) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042)
10.13(c)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.12(d) to Form 10-K for fiscal year ended September 30, 2008 (File No. 1-10042)
10.13(d)*	Form of Award Agreement of Time-Lapse Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 99.4 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.13(e)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 99.5 to Form S-8 dated October 28, 2011 (File No. 333-177593)
10.14*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 10, 2011)	
12	Statement of computation of ratio of earnings to fixed charges	
	Other Exhibits, as indicated	
21	Subsidiaries of the registrant	
23.1	Consent of independent registered public accounting firm, Ernst & Young LLP	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2011
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications**	
101.INS	XBRL Instance Document***	
101.SCH	XBRL Taxonomy Extension Schema***	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase***	
101.DEF	XBRL Taxonomy Extension Definition Linkbase***	
101.LAB	XBRL Taxonomy Extension Labels Linkbase***	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase***	

* This exhibit constitutes a "management contract or compensatory plan, contract, or arrangement."

** These certifications pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Annual Report on Form 10-K, will not be deemed to be filed with the Securities and Exchange Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

*** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011

SUMMARY
- with Test Year Normalized Revenues

Line No.	Description	(a) Total Kansas	(b) Sales Residential	(c) Sales Com/PA	(d) Sales Schools	(e) Sales Indus/Inter	(f) Sales Irrigation	(g) Transport Firm	(h) Transport Interr.	(i) Transport Firm Schools
1	Margin with test year rates, as filed	$49,532,317	$36,094,111	$8,842,284	$126,169	$167,246	$816,968	$2,200,200	$1,039,875	$245,466
2	O&M Expense	18,684,894	14,252,184	3,042,923	61,390	55,144	283,303	654,840	242,725	92,384
3	Interest on Customer Deposits	2,947	2,720	227	-	-	-	-	-	-
4	Depreciation & Amort	13,347,372	9,657,887	2,322,274	48,712	44,363	242,757	678,629	260,625	92,124
5	Taxes Other than Income Tax	7,238,894	5,271,956	1,249,806	26,103	23,737	129,030	354,329	135,672	48,263
6	Income Tax	2,061,456	1,298,308	519,443	(11,721)	10,408	26,597	105,263	121,494	(8,335)
7										
8	Return on Rate Base at test year rates	$8,196,753	$5,611,055	$1,707,612	$1,685	$33,594	$135,281	$407,139	$279,358	$21,029
9										
10	Rate Base	$160,074,633	$115,049,286	$28,985,849	$621,649	$561,116	$3,001,907	$7,811,947	$2,971,795	$1,071,086
11										
12	ROR at test year rates	5.1%	4.9%	5.9%	0.3%	6.0%	4.5%	5.2%	9.4%	2.0%

SUMMARY
- with Proposed Proforma Revenue

Line No.	Description	(a) Total Kansas	(b) Sales Resid.	(c) Sales Com/PA	(d) Sales Schools	(e) Sales Indus/Inter	(f) Sales Irrigation	(g) Transport Firm	(h) Transport Interr.	(i) Transport Firm Schools
13	Proforma Margin with Proposed Rates	$59,237,824	$43,487,520	$10,401,903	$147,593	$196,089	$938,124	$2,581,988	$1,193,093	$291,513
14	O&M Expense	18,684,894	14,252,184	3,042,923	61,390	55,144	283,303	654,840	242,725	92,384
15	Interest on Customer Deposits	2,947	2,720	227	-	-	-	-	-	-
16	Depreciation & Amort	13,347,372	9,657,887	2,322,274	48,712	44,363	242,757	678,629	260,625	92,124
17	Taxes Other than Income Tax	7,238,894	5,271,956	1,249,806	26,103	23,737	129,030	354,329	135,672	48,263
18	Income Tax (proposed)	5,903,139	4,224,673	1,136,869	(3,249)	21,827	74,554	256,396	182,185	9,883
19										
20	Return on Rate Base at Proposed Rates	$14,060,578	$10,078,099	$2,649,804	$14,636	$51,019	$208,481	$637,794	$371,886	$48,858
21										
22	Rate Base (proposed)	$160,074,633	$115,049,286	$28,985,849	$621,649	$561,116	$3,001,907	$7,811,947	$2,971,795	$1,071,086
23										
24	ROR by class per Proposed Rates	8.8%	8.8%	9.1%	2.4%	9.1%	6.9%	8.2%	12.5%	4.6%

Line No.	Description	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
25	Interest Deduction [Factor RB]	$ (5,046,357)	$ (3,626,932)	$ (913,780)	$ (19,598)	$ (17,689)	$ (94,635)	$ (246,272)	$ (93,686)	$ (33,766)
26	Composite Income Tax Rate (Section 11B)	39.583%								
27	Weighted Cost of Capital - LTD (Section 7)	3.153%								
28	Allocation of proposed income tax	100.00%	71.57%	19.26%	-0.06%	0.37%	1.26%	4.34%	3.09%	0.17%

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011

Allocation of Test Year Rate Base

Line No.	(a) Acct.	(b) Description	(c) Tot. Kansas	(d) Sales Resid.	(e) Sales Com/PA	(f) Sales Schools	(g) Sales Indus/Inter	(h) Sales Irrigation	(i) Transport Firm	(j) Transport Interr.	(k) Transport Firm Schools	(l) Factor
1	301-303	Total Intangible Plant	$41,078	$29,723	$7,147	$150	$137	$747	$2,089	$802	$284	GP
2	350-357	Total Underground Storage	5,919,327	4,367,941	1,372,304	32,038	30,947	116,096	-	-	-	P&C W
3	365-371	Total Transmission Plant	4,233,511	2,710,601	859,636	19,578	19,709	106,866	336,493	138,643	41,984	P&C
4	374	Land and Land Rights	963,586	616,958	195,661	4,456	4,486	24,324	76,589	31,556	9,556	P&C
5	375	Structures & Improvements	119,494	76,509	24,264	553	556	3,016	9,498	3,913	1,185	P&C
6	376	Mains	125,538,983	80,379,176	25,491,339	580,565	584,441	3,168,963	9,978,249	4,111,261	1,244,988	P&C
7	378	Meas. & Reg. Sta. Equip.-Gen	3,531,317	2,261,006	717,052	16,331	16,440	89,141	280,681	115,647	35,021	P&C
8	379	Meas. & Reg. Sta. Equip.-City	2,213,402	1,417,181	449,443	10,236	10,304	55,873	175,928	72,486	21,951	P&C
9	380	Services	57,635,135	52,802,957	4,475,812	32,194	40,689	126,539	110,442	18,332	28,169	MQ
10	381	Meters	15,021,142	11,044,206	2,986,362	64,533	33,860	248,162	462,608	82,403	99,008	analysis
11	382	Meter Installations	23,917,803	17,585,423	4,755,112	102,754	53,914	395,142	736,600	131,208	157,648	MI
12	383	House Regulators	2,209,798	1,977,722	214,752	952	1,524	12,810	1,277	157	603	MIS
13	384	House Reg. Installations	209,461	187,463	20,356	90	144	1,214	121	15	57	MIS
14	385	Ind. Meas. & Reg. Sta. Equip.	935,854	5,401	620,404	20,540	8,795	61,294	157,975	28,275	33,172	MIL
15	387	Other Equipment	18,236	11,676	3,703	84	85	460	1,449	597	181	P&C
16	374-388	Total Distribution Plant (DP)	232,314,213	168,365,678	39,954,261	833,288	755,240	4,186,938	11,991,417	4,595,852	1,631,538	
17	389-399	Total General Plant	25,992,651	$18,807,753	$4,522,393	$94,862	$86,393	$472,745	$1,321,561	$507,541	$179,403	GP
18												
19	1010	Total Gross Plant (GP)	$268,500,779	$194,281,697	$46,715,740	$979,917	$892,426	$4,883,392	$13,651,560	$5,242,838	$1,853,209	
20												
21		Total Intangible Plant	20,045	14,504	3,488	73	67	365	1,019	391	138	GP
22		Total Underground Storage	(3,809,876)	(2,811,352)	(883,260)	(20,621)	(19,919)	(74,723)	-	-	-	P&C W
23		Total Transmission Plant	(2,420,430)	(1,549,735)	(491,481)	(11,193)	(11,268)	(61,099)	(192,384)	(79,266)	(24,004)	P&C
24		Land and Land Rights	(116,859)	(74,822)	(23,729)	(540)	(544)	(2,950)	(9,288)	(3,827)	(1,159)	P&C
25		Structures & Improvements	(52,690)	(33,736)	(10,699)	(244)	(245)	(1,330)	(4,188)	(1,726)	(523)	P&C
26		Mains	(44,877,755)	(28,733,999)	(9,112,660)	(207,541)	(208,926)	(1,132,843)	(3,567,031)	(1,469,696)	(445,059)	P&C
27		Meas. & Reg. Sta. Equip.-Gen	(1,711,750)	(1,095,987)	(347,580)	(7,916)	(7,969)	(43,209)	(136,055)	(56,058)	(16,976)	P&C
28		Meas. & Reg. Sta. Equip.-City	(1,208,193)	(773,573)	(245,330)	(5,587)	(5,625)	(30,498)	(96,031)	(39,567)	(11,982)	P&C
29		Services	(21,925,205)	(20,086,978)	(1,702,661)	(12,247)	(15,479)	(48,137)	(42,014)	(6,974)	(10,716)	MQ
30		Meters	(7,602,543)	(5,589,725)	(1,511,466)	(32,662)	(17,137)	(125,600)	(234,136)	(41,706)	(50,110)	MI
31		Meter Installations	(2,658,473)	(1,954,626)	(528,533)	(11,421)	(5,993)	(43,920)	(81,873)	(14,584)	(17,523)	MI
32		House Regulators	(1,329,026)	(1,189,450)	(129,157)	(573)	(917)	(7,704)	(768)	(95)	(363)	MIS
33		House Reg. Installations	(185,948)	(166,419)	(18,071)	(80)	(128)	(1,078)	(107)	(13)	(51)	MIS
34		Ind. Meas. & Reg. Sta. Equip.	(275,388)	(1,589)	(182,562)	(6,044)	(2,588)	(18,036)	(46,486)	(8,320)	(9,761)	MIL
35		Other Equipment	(2,677)	(1,714)	(544)	(12)	(12)	(68)	(213)	(88)	(27)	P&C
36		Total Distribution Plant (DP)	(81,946,507)	(59,702,618)	(13,812,991)	(284,867)	(265,564)	(1,455,375)	(4,218,192)	(1,642,653)	(564,248)	
37		Total General Plant	(11,670,465)	(8,444,511)	(2,030,513)	(42,592)	(38,790)	(212,258)	(593,369)	(227,881)	(80,550)	GP
38												
39	1080	Accumulated Depreciation	(99,827,232)	(72,493,711)	(17,214,758)	(359,201)	(335,474)	(1,803,090)	(5,002,925)	(1,949,410)	(668,664)	

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011

Allocation of Test Year Rate Base

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Line No.	Acct.	Description	Tot. Kansas	Sales Resid.	Sales Com/PA	Sales Schools	Sales Indus/Inter	Sales Irrigation	Transport Firm	Transport Interr.	Transport Firm Schools	Factor
40												
41		Net Plant	$168,673,547	$121,787,986	$29,500,983	$620,716	$556,952	$3,080,302	$8,648,635	$3,293,428	$1,184,545	
42												
43		Work in Progress	18,782,485	13,590,624	3,267,915	68,548	62,428	341,609	954,970	366,753	129,638	GP
44		Storage Gas	11,175,793	8,246,750	2,590,934	60,489	58,429	219,191	-	-	-	P&C W
45		Accum. Deferred Income Tax	(35,687,906)	(25,823,042)	(6,209,244)	(130,246)	(118,617)	(649,078)	(1,814,503)	(696,854)	(246,320)	GP
46		Customer Advances	(1,065,228)	(983,276)	(81,952)	-	-	-	-	-	-	CD
47		Customer Deposits	(2,455,902)	(2,266,960)	(188,942)	-	-	-	-	-	-	CD
48												
49		Working Capital:										
50		Prepayments	651,845	497,204	106,156	2,142	1,924	9,883	22,845	8,468	3,223	OM
51		Cash Requirements	0	0	0	0	0	0	0	0	0	OM
52												
53		Rate Base test year	$160,074,634	$115,049,286	$28,985,849	$621,649	$561,116	$3,001,907	$7,811,947	$2,971,795	$1,071,086	

Data per Section 3 Summary
Note: The class for Transport Schools Interruptible was eliminated since there are no longer any such customers.

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011

Test Year Margin - Normalized & Adjusted

Line No.	(a) Acct.	(b) Description	(c) Total Kansas	(d) Sales Resid.	(e) Sales Com/PA	(f) Sales Schools	(g) Sales Indus/Inter	(h) Sales Irrigation	(i) Transport Firm	(j) Transport Interr.	(k) Transport Firm Schools	(l) Factor
1	480/489	Gas Sales & Transp Revenue	$47,868,823	$34,938,286	$8,564,045	$121,007	$161,001	$759,819	$2,090,625	$999,414	$234,626	direct
2		Special contracts	563,358	332,619	107,396	2,161	3,726	24,689	47,776	40,322	4,669	AD
3		Ad Valorem Surcharge	664,875	424,438	137,042	2,758	2,211	31,504	60,965	0	5,958	Surch
4		Other - Misc. Service Revenue	435,260	398,768	33,801	243	307	956	834	138	213	MQ
5		Total Revenue, Adjusted	$49,532,317	$36,094,111	$8,842,284	$126,169	$167,246	$816,968	$2,200,200	$1,039,875	$245,466	
6												
7		Weather Adjusted Gas Cost	0	0	0	0	0	0	0	0	0	direct
8												
9		Margin (revenue less gas cost)	$49,532,317	$36,094,111	$8,842,284	$126,169	$167,246	$816,968	$2,200,200	$1,039,875	$245,466	

Test Year Margin - Proposed

Line No.	(a) Acct.	(b) Description	(c) Total Kansas	(d) Sales Resid.	(e) Sales Com/PA	(f) Sales Schools	(g) Sales Indus/Inter	(h) Sales Irrigation	(i) Transport Firm	(j) Transport Interr.	(k) Transport Firm Schools	(l) Factor
10	480/489	Gas Sales & Transp Revenue	$57,983,992	$42,524,271	$10,240,209	$145,026	$191,840	$911,670	$2,532,392	$1,152,124	$286,460	direct
11		Special contracts	569,357	336,161	108,539	2,184	3,766	24,952	48,285	40,751	4,719	AD
12		Ad Valorem Surcharge										
13	488	Other - Misc. Service Revenue	684,475	627,088	53,155	382	483	1,503	1,312	218	335	MQ
14		Total Revenue, Adjusted	$59,237,824	$43,487,520	$10,401,903	$147,593	$196,089	$938,124	$2,581,988	$1,193,093	$291,513	
15												
16		Weather Adjusted Gas Cost	0	0	0	0	0	0	0	0	0	direct
17												
18		Margin (revenue less gas cost)	$59,237,824	$43,487,520	$10,401,903	$147,593	$196,089	$938,124	$2,581,988	$1,193,093	$291,513	

Data from Section 17
Notes: The class for Transport Schools Interruptible was eliminated since there are no longer any such customers.
Special Contracts revenue is distributed over all classes in keeping with past rate case precedent.

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011

Allocation of Test Year O&M Expense - Normalized & Adjusted

Line No.	Acct.	Description	Tot. Kansas	Sales Resid.	Sales Com/PA	Sales Schools	Sales Indus/Inter	Sales Irrigation	Transport Firm	Transport Interr.	Transport Firm Schools	Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1		**PRODUCTION**										
2	752	Gas Wells Expenses	-	$0	$0	$0	$0	$0	$0	$0	$0	P&C S
3	764	Maintenance of Field Lines	-	0	0	0	0	0	0	0	0	P&C S
4	767	Maintenance of Purification equipment	-	0	0	0	0	0	0	0	0	P&C S
5		**STORAGE**										
6	815	Maps and Records	-	0	0	0	0	0	0	0	0	P&C W
7	816	Wells Expense	690,917	509,836	160,178	3,740	3,612	13,551	0	0	0	P&C W
8	819	Compressor Station Fuel and Power	112,899	83,309	26,174	611	590	2,214	0	0	0	P&C W
9	824	Other Expenses	21,090	15,563	4,889	114	110	414	0	0	0	P&C W
10	825	Storage Well Royalties	61,209	45,167	14,190	331	320	1,200	0	0	0	P&C W
11	830	Storage-Maintenance Supervision & Engineering	174	128	40	1	1	3	0	0	0	P&C W
12	831	Storage-Maintenance of structures & improvements	117	87	27	1	1	2	0	0	0	P&C W
13	832	Maintenance of reservoirs and wells	3,432	2,533	796	19	18	67	0	0	0	P&C W
14	834	Maintenance of compressor station equipment	18,289	13,496	4,240	99	96	359	0	0	0	P&C W
15	836	Processing-Maintenance of purification equipment	16	11	4	0	0	0	0	0	0	P&C W
16	841	Operation Labor and Expense	28,502	21,032	6,608	154	149	559	0	0	0	P&C W
17		**TRANSMISSION**										
18	850	Operation supervision and engineering	-	0	0	0	0	0	0	0	0	P&C
19	853	Compressor station labor and expenses	-	0	0	0	0	0	0	0	0	P&C
20	854	Gas for Compressor Station fuel	-	0	0	0	0	0	0	0	0	P&C
21	856	Mains Expense	490	314	100	2	2	12	39	16	5	P&C
22	857	Measuring & Regulating Station Equipment	3,209	2,054	652	15	15	81	255	105	32	P&C
23	860	Rents	-	0	0	0	0	0	0	0	0	P&C
24	861	Maintenance Supervision & Engineering	55	35	11	0	0	1	4	2	1	P&C
26		**DISTRIBUTION**										
25	870	Supervision & Engineering	749,345	543,075	128,875	2,688	2,436	13,505	38,679	14,824	5,263	DP
27	871	Load Dispatching	8,487	6,150	1,460	30	28	153	438	168	60	DP
28	871	Odorization	25,956	18,811	4,464	93	84	468	1,340	513	182	DP
29	874	Mains & Service Expenses	2,983,684	2,162,373	513,145	10,702	9,700	53,774	154,010	59,026	20,954	DP
30	875	Meas. & Reg. Sta. Expenses - General	71,802	45,973	14,580	332	334	1,812	5,707	2,351	712	acct 378
31	877	Meas. & Reg. Sta. Expenses - City Gate	828	530	168	4	4	21	66	27	8	acct 379
32	878	Meter & House Reg. Expenses	448,638	329,858	89,194	1,927	1,011	7,412	13,817	2,461	2,957	acct 381
33	879	Customer Installations Expenses	105,042	77,231	20,883	451	237	1,735	3,235	576	692	acct 382
34	880	Other Expenses	325,159	235,654	55,922	1,166	1,057	5,860	16,784	6,433	2,284	DP
35	881	Rents	91,123	66,040	15,672	327	296	1,642	4,704	1,803	640	DP
36	885	Supervision & Engineering	239,966	173,911	41,270	861	780	4,325	12,386	4,747	1,685	DP
37	886	Structures - Improvements	8,278	5,300	1,681	38	39	209	658	271	82	acct 375
38	887	Mains	164,864	105,558	33,476	762	768	4,162	13,104	5,399	1,635	acct 376
39	889	Meas. & Reg. Sta. Equip. - General	102,362	65,540	20,785	473	477	2,584	8,136	3,352	1,015	acct 378
40	890	Maintenance of Meas. & Reg. Sta Equip - Industrial	462	3	306	10	4	30	78	14	16	acct 385
41	892	Services	18,297	16,763	1,421	10	13	40	35	6	9	acct 380

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011

Allocation of Test Year O&M Expense - Normalized & Adjusted

Line No.	Acct.	Description	Tot. Kansas	Sales Resid.	Sales Com/PA	Sales Schools	Sales Indus/Inter	Sales Irrigation	Transport Firm	Transport Interr.	Transport Firm Schools	Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
42	893	Meter & House Regulators	7,993	5,877	1,589	34	18	132	246	44	53	acct 381
43	894	Maintenance of other equipment	129	83	26	1	1	3	10	4	1	acct 387
44		**CUSTOMER ACCOUNTS**										
45	901	Supervision	53,090	48,698	4,059	34	36	112	109	16	26	B
46	902	Meter Reading Expenses	810,168	742,243	62,916	453	572	1,779	1,552	258	396	MQ
47	903	Customer Records & Collection Expenses	69,524	63,773	5,315	44	48	147	142	21	34	B
48	904	Uncollectible Accounts	662,680	607,861	50,663	423	454	1,403	1,356	201	320	B
49	905	Misc. Customer Accounts Expenses	5,678	5,208	434	4	4	12	12	2	3	B
50		**CUSTOMER SERVICE**										
51	907	Supervision	1,065	977	81	1	1	2	2	0	1	B
52	908	Customer Assistance Expenses	50	46	4	0	0	0	0	0	0	B
53	909	Informational Advertising	4,851	4,450	371	3	3	10	10	1	2	B
54	910	Miscellaneous Customer Service Expenses	429	393	33	0	0	1	1	0	0	B
55		**SALES**										
56	911	Supervision	160	147	12	0	0	0	0	0	0	B
57	912	Demonstrating and Selling	(4)	(4)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	B
58	916	Misc sales expenses	925	848	71	1	1	2	2	0	0	B
59		**ADMINISTRATIVE & GENERAL**										
60	920	Administrative & general salaries	231,876	176,867	37,762	762	684	3,516	8,126	3,012	1,146	OM(F)
61	921	Office Supplies & Expense	14,600	11,136	2,378	48	43	221	512	190	72	OM(F)
62	922	Administrative Expense Transfer - Credit	8,440,201	6,437,891	1,374,527	27,731	24,909	127,971	295,799	109,642	41,731	OM(F)
63	923	Outside services employed	3,491	2,663	568	11	10	53	122	45	17	OM(F)
64	924	Property Insurance	109,159	83,262	17,777	359	322	1,655	3,826	1,418	540	OM(F)
65	925	Injuries and Damages	10,504	8,012	1,711	35	31	159	368	136	52	OM(F)
66	926	Employee Welfare and Pensions	1,664,760	1,269,821	271,114	5,470	4,913	25,241	58,344	21,626	8,231	OM(F)
67	928	Regulatory Commission Expense	210,000	160,181	34,199	690	620	3,184	7,360	2,728	1,038	OM(F)
68	930	Miscellaneous General Expense	78,878	60,165	12,846	259	233	1,196	2,764	1,025	390	OM(F)
69	931	Rents	19,995	15,252	3,256	66	59	303	701	260	99	OM(F)
70	932	Maintenance of General Plant	-	0	0	0	0	0	0	0	0	OM(F)
71												
72		**Total O&M adjusted**	18,684,894	$14,252,184	$3,042,923	$61,390	$55,144	$283,303	$654,840	$242,725	$92,384	
73												
74	403	Depreciation & Amort	13,347,372	9,657,887	2,322,274	48,712	44,363	242,757	678,629	260,625	92,124	GP
75	408	Taxes Other than Income Tax	7,238,894	5,271,956	1,249,806	26,103	23,737	129,030	354,329	135,672	48,263	OT
76		Interest on Customer Deposits	2,947	2,720	227	0	0	0	0	0	0	CD
77		Income Tax	2,061,456	1,298,308	519,443	(11,721)	10,408	26,597	105,263	121,494	(8,335)	IT
78												
79		**Total Cost of Service**	$41,335,564	$30,483,055	$7,134,672	$124,484	$133,651	$681,686	$1,793,061	$760,517	$224,437	

Data per Section 3 Summary

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011

Allocation Factors

Line No.	Factor	Description	Total Kansas	Sales Resid.	Sales Com/PA	Sales Schools	Sales Indus/Inter	Sales Irrigation	Transport Firm	Transport Interr.	Transport Firm Schools
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1		Peak Day(Ccf)	1,684,758	1,106,700	349,074	8,234	6,743	32,093	130,921	33,370	17,623
2	P	Peak Day factor	100.00%	65.69%	20.72%	0.49%	0.40%	1.90%	7.77%	1.98%	1.05%
3	P(S)	Peak Day(Sales) factor	100.00%	73.64%	23.23%	0.55%	0.45%	2.14%	0.00%	0.00%	0.00%
4											
5		Annual Delivery or Thru-put (Ccf adj.)	170,174,970	100,475,009	32,441,250	652,838	1,125,665	7,457,811	14,431,833	12,180,190	1,410,374
6		Annual Delivery w/o interruptible		100,475,009	32,441,250	652,838	523,366	7,457,811	14,431,833	0	1,410,374
7	AD	Annual Delivery factor	100.00%	59.04%	19.06%	0.38%	0.66%	4.38%	8.48%	7.16%	0.83%
8	AV	Annual Vol Ccf excl. Transp. factor	100.00%	70.68%	22.82%	0.46%	0.79%	5.25%	0.00%	0.00%	0.00%
9	Surch	Ad Valorem Surcharge factor	100.00%	63.84%	20.61%	0.41%	0.33%	4.74%	9.17%	0.00%	0.90%
10											
11		Winter Volume Ccf excl. Transp.	116,837,006	86,744,002	26,932,215	609,090	870,699	1,681,000	0	0	0
12	WV	Winter Vol Ccf excl. Transp. factor	100.00%	74.24%	23.05%	0.52%	0.75%	1.44%	0.00%	0.00%	0.00%
13											
14	P&C	Peak & Commodity (75%P / 25%AD)	100.00%	64.03%	20.31%	0.46%	0.47%	2.52%	7.95%	3.27%	0.99%
15											
16	P&C S	P&C Sales (75%P(S) / 25%AV)	100.00%	72.90%	23.13%	0.53%	0.53%	2.91%	0.00%	0.00%	0.00%
17											
18	P&C W	P&C Winter (75%P(S) / 25% WV)	100.00%	73.79%	23.18%	0.54%	0.52%	1.96%	0.00%	0.00%	0.00%
19											
20		Number of Bills (avg monthly)	128,500	117,870	9,824	82	88	272	263	39	62
21	B	Bills factor	100.00%	91.73%	7.65%	0.06%	0.07%	0.21%	0.20%	0.03%	0.05%
22											
23		Meter Quantity	128,899	118,092	10,010	72	91	283	247	41	63
24	MQ	Meter Quantity factor	100.00%	91.62%	7.77%	0.06%	0.07%	0.22%	0.19%	0.03%	0.05%
25											
26		Meter $ Investment	$15,021,142	$11,044,206	$2,986,362	$64,533	$33,860	$248,162	$462,608	$82,403	$99,008
27	MI	Meter Investment factor	100.00%	73.52%	19.88%	0.43%	0.23%	1.65%	3.08%	0.55%	0.66%
28											
29		Meter $ Inv Small Class 1,2,3	$12,322,792	$11,028,633	$1,197,552	$5,311	$8,501	$71,434	$7,119	$878	$3,364
30	MIS	Meter $ Class 1,2,3 factor	100.00%	89.50%	9.72%	0.04%	0.07%	0.58%	0.06%	0.01%	0.03%
31											
32		Meter $ Inv Large Class 4-9	$2,698,350	$15,573	$1,788,810	$59,222	$25,359	$176,728	$455,489	$81,525	$95,644
33	MIL	Meter $ Class 4-9 factor	100.00%	0.58%	66.29%	2.19%	0.94%	6.55%	16.88%	3.02%	3.54%

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011

Allocation Factors

Line No.	Factor	Description	Total Kansas	Sales Resid.	Sales Com/PA	Sales Schools	Sales Indus/Inter	Sales Irrigation	Transport Firm	Transport Interr.	Transport Firm Schools
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
34											
35		Distribution Plant $	$232,314,212	168,365,678	39,954,261	833,288	755,240	4,186,938	11,991,417	4,595,852	1,631,538
36	DP	Distribution Plant factor	100.00%	72.47%	17.20%	0.36%	0.33%	1.80%	5.16%	1.98%	0.70%
37											
38		Functional Plant $	242,467,050	175,444,221	42,186,201	884,905	805,896	4,409,900	12,327,910	4,734,494	1,673,523
39	GP	Gross Plant factor	100.00%	72.36%	17.40%	0.36%	0.33%	1.82%	5.08%	1.95%	0.69%
40											
41		Total Adjusted Revenue, test yr	$49,532,317	$36,094,111	$8,842,284	$126,169	$167,246	$816,968	$2,200,200	$1,039,875	$245,466
42	R	Total Adjusted Revenue factor	100.00%	72.87%	17.85%	0.25%	0.34%	1.65%	4.44%	2.10%	0.50%
43											
44		Resid. & Comm. Customers	127,694	117,870	9,824	-	-	-	-	-	-
45	CD	Customer Deposits factor	100.00%	92.31%	7.69%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
46											
47		Adjusted Functional O&M Expense $	$7,901,430	$6,026,935	$1,286,785	$25,960	$23,319	$119,802	$276,917	$102,643	$39,067
48	OM(F)	Adj. Funct. O&M Expense factor	100.00%	76.28%	16.29%	0.33%	0.30%	1.52%	3.50%	1.30%	0.49%
49											
50		Adjusted O&M Expense $	$18,684,894	$14,252,184	$3,042,923	$61,390	$55,144	$283,303	$654,840	$242,725	$92,384
51	OM	Adjusted O&M Expense factor	100.00%	76.28%	16.29%	0.33%	0.30%	1.52%	3.50%	1.30%	0.49%
52											
53	OT	Other Taxes (88% GP / 12%OM)	100.00%	72.83%	17.27%	0.36%	0.33%	1.78%	4.89%	1.87%	0.67%
54											
55		Net taxable Income	$5,211,852	$3,282,432	$1,313,275	($29,633)	$26,313	$67,242	$266,130	$307,166	($21,072)
56	IT	Income Tax factor	100.00%	62.98%	25.20%	-0.57%	0.50%	1.29%	5.11%	5.89%	-0.40%
57											
58		Rate Base	160,074,633	$115,049,286	$28,985,849	$621,649	$561,116	$3,001,907	$7,811,947	$2,971,795	$1,071,086
59	RB	Rate Base factor	100.00%	71.87%	18.11%	0.39%	0.35%	1.88%	4.88%	1.86%	0.67%

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011
Summary Results of Kansas Meter Analysis

line	(a)	(b) Sales Resid.	(c) Sales Com/PA	(d) Sales Schools	(e) Sales Indus/Inter	(f) Sales Irrigation	(g) Transport Firm	(h) Transport Interr.	(i) Transport Firm Schools	(j) Total
1	**Meter Quantity**									
2	**MQ**	118,092	10,010	72	91	283	247	41	63	128,899
3										
4	**Relative Meter Quantity Factor**									
5	**MQ f**	91.62%	7.77%	0.06%	0.07%	0.22%	0.19%	0.03%	0.05%	100.00%
6										
7										
8	**Meter Investment by Class for**									
9	**MI**	$11,044,206	$2,986,362	$ 64,533	$ 33,860	$248,162	$462,608	$ 82,403	$ 99,008	$15,021,142
10										
11	**Relative Meter Investment Factor**									
12	**MI f**	73.52%	19.88%	0.43%	0.23%	1.65%	3.08%	0.55%	0.66%	100.00%
13										
14										
15	**SPECIAL SUMMARY RESULTS FOR**									
16	**USE WITH HOUSE REGULATORS**									
17	**Summary totals from above for**									
18	**Meter Size Class 1,2,& 3 only**									
19	**MIS**	$11,028,633	$1,197,552	$ 5,311	$ 8,501	$ 71,434	$ 7,119	$ 878	$ 3,364	$12,322,792
20										
21	**Relative meter Investment Factor**									
22	**for meter size class 1,2,&3**									
23	**MIS f**	89.50%	9.72%	0.04%	0.07%	0.58%	0.06%	0.01%	0.03%	100.00%
24										
25										
26	**SPECIAL SUMMARY RESULTS FOR**									
27	**USE WITH LARGE METERS**									
28	**Summary totals from above for**									
29	**Meter Size Class 4-9 only**									
30	**MIL**	$ 15,573	$1,788,810	$ 59,222	$ 25,359	$176,728	$455,489	$ 81,525	$ 95,644	$ 2,698,350
31										
32	**Relative meter Investment Factor for**									
33	**meter size class 4-9:**									
34	**MIL f**	0.58%	66.29%	2.19%	0.94%	6.55%	16.88%	3.02%	3.54%	100.00%

Source: Kansas Meter Analysis 2011.xls
Note: The class for Transport Schools Interruptible was eliminated since there are no longer any such customers.

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011
Plant in Service

Line No.	Property Description	Property Type	Liberty/Buffalo Div 79	Kansas Div 81	Southwest Div Div 86	Total Kansas
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Intangible Plant**					
2	Franchises & Consents	30200	-	37,160	-	37,160
3	Misc. Intangible Plant	30300	-	3,918	-	3,918
4	Total Intangible Plant		-	41,078	-	41,078
5						
6	**Underground Storage**					
7	Land	35010	49,164	-	-	49,164
8	Rights-of-way	35020	568,935	-	-	568,935
9	Well Structures	35100	102,923	-	-	102,923
10	Wells	35200	1,136,225	-	-	1,136,225
11	Reservoirs	35202	36,515	-	-	36,515
12	Pipelines	35300	1,090,230	-	-	1,090,230
13	Compressor Station Equipment	35400	2,259,430	-	-	2,259,430
14	Meas. & Reg. Equipment	35500	220,011	-	-	220,011
15	Purification Equipment	35600	288,382	-	-	288,382
16	Other Equip	35700	167,513	-	-	167,513
17	Total Underground Storage Plant		5,919,327	-	-	5,919,327
18						
19	**Transmission Plant**					
20	Land and Land Rights	36500	-	4,761	6,490	11,252
21	Rights-of-way	36520	-	-	9,037	9,037
22	Structures & Improvements	36600	-	-	33,191	33,191
23	Mains Cathodic Protection	36700	-	1,617,348	1,861,506	3,478,854
24	Mains Steel	36701	-	139,979	3,474	143,453
25	Compressor Station Equipment	36800	-	-	31,496	31,496
26	Meas. & Reg. Sta. Equipment	36900	-	148,706	377,522	526,227
27	Other Equipment	37100	-	-	-	-
28	Total Transmission Plant		-	1,910,794	2,322,717	4,233,511
29						
30	**Distribution Plant**					
31	Land & Land Rights	37400	-	650,876	20,107	670,983
32	Land Rights	37402	-	286,730	5,873	292,603
33	Structures & Improvements	37500	-	119,134	360	119,494
34	Mains Cathodic Protection	37600	-	8,182,975	589,833	8,772,808
35	Mains Steel	37601	-	34,184,581	3,682,507	37,867,087
36	Mains Plastic	37602	-	76,174,834	2,724,253	78,899,087
37	Meas. & Reg. Sta. Eq-General	37800	-	3,313,148	218,169	3,531,317
38	Meas. & Reg. City Gate	37900	-	2,192,034	6,518	2,198,552
39	Meas. & Reg. Sta. Equipment-	37908	-	-	14,851	14,851
40	Services	38000	-	53,677,076	3,958,059	57,635,135
41	Meters	38100	-	14,184,666	836,477	15,021,142
42	Meter Installations	38200	-	22,001,839	1,915,964	23,917,803
43	House Regulators	38300	-	2,145,570	64,228	2,209,798
44	House Reg. Installations	38400	-	203,477	5,985	209,461
45	Ind. Meas. & Reg. Sta. Equip	38500	-	875,840	60,014	935,854
46	Other Equipment	38700	-	10,034	8,202	18,236
47	Total Distribution Plant		-	218,202,813	14,111,399	232,314,213
48						

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011
Plant in Service

Line No.	Property Description	Property Type	Liberty/Buffalo Div 79	Kansas Div 81	Southwest Div Div 86	Total Kansas
	(a)	(b)	(c)	(d)	(e)	(f)
49	**General Plant**					
50	Land & Land Rights	38900	-	152,535	-	152,535
51	Structures & Improvements	39000	-	1,787,101	66,567	1,853,668
52	Improvements	39003	-	1,513	-	1,513
53	Air Conditioning Equipment	39004	-	-	8,782	8,782
54	Improv. to Leased Premises	39009	-	39,013	-	39,013
55	Office Furniture & Equipment	39100	-	411,635	-	411,635
56	Office Furn. Copiers & Type	39103	-	-	5,220	5,220
57	Transportation Equipment	39200	-	266,687	7,815	274,502
58	Stores Equipment	39300	-	1,308	-	1,308
59	Tools, Shop, & Garage Equip.	39400	7,047	1,949,357	135,461	2,091,865
60	Laboratory Equipment	39500	-	5,233	3,056	8,289
61	Power Operated Equipment	39600	-	389,595	43,927	433,521
62	Ditchers	39603	-	67,799	33,393	101,192
63	Backhoes	39604	-	203,475	-	203,475
64	Welders	39605	-	54,819	-	54,819
65	Communication Equipment	39700	-	380,223	25,032	405,255
66	Miscellaneous Equipment	39800	-	1,594,048	12,147	1,606,195
67	Other Tangible Property	39900	-	27,091	-	27,091
68	Oth Tang Prop - Servers - H/W	39901		25,349		25,349
69	Oth Tang Prop - Servers - S/W	39902	-	63,702	-	63,702
70	Oth Tang Prop Network H/W	39903	-	180,428	-	180,428
71	Oth Tang Prop PC Hardware	39906	-	1,117,300	15,269	1,132,569
72	Oth Tang Prop PC Software	39907	-	84,070	-	84,070
73	Oth Tang Prop Appl Software	39908	-	213,445	-	213,445
74	Total Direct General Plant		7,047	9,015,726	356,669	9,379,442
75	rounding					
76	**Total Kansas Direct Gross Plant**		5,926,374	229,170,412	16,790,784	251,887,571
77						
78	General Plant Alloc from Shared Services	Wp 4-2				6,584,416
79	General Plant Alloc from Customer Support	Wp 4-3				8,343,802
80	General Plant Alloc from CO/KS Gen Office	Wp 4-4				1,684,990
81						
82	**Total KS Direct and Allocated Gross Plant**					268,500,779

Data from Section 4 Plant

Accumulated Depreciation

Line No.	Description	Property Type	Liberty Div 79	Kansas Div 81	Southwest Div Div 86	Total Kansas
	(a)	(b)	(c)	(d)	(e)	(f)
		Kansas Direct Accumulated Depreciation by Functional Plant Account				
1	**Intangible Plant A/D**					
2	Organization	301		$ (25,000)		$ (25,000)
3	Franch & Consent Grp	302		15,036		15,036
4	Intangibles Grp	303		(10,081)		(10,081)
5	Total Intangible Plant		0	(20,045)	0	(20,045)
6						
7	**Production and Gathering Plant A/D**					0
8	Rights-of-way	325.4				0
9	Field Measuring And R	328				0
10	Field Lines	332				0
11	Field Compressor Stat	333				0
12	Field Measuring And R	334				0
13	Total Prod & Gathering Plant		0	0	0	0
14						
15	**Underground Storage A/D**					
16	Rights-of-way	350.2	57,842			57,842
17	Structures And Improv	351	30,470			30,470
18	Meas & Reg Structures	351.3	6,363			6,363
19	Other Structures	351.4	20,851			20,851
20	Wells	352	723,964			723,964
21	Leaseholds & Rights	352.1	(12,263)			(12,263)
22	Reservoirs	352.2	21,521			21,521
23	Pipeline	353	614,570			614,570
24	Compressor Equip	354	1,964,165			1,964,165
25	Meas & Reg Equip	355	131,709			131,709
26	Purification Equip	356	176,260			176,260
27	Other Equip	357	74,425			74,425
28	Total Underground Storage Plant		3,809,876	0	0	3,809,876
29						
30	**Transmission Plant A/D**					
31	Land	365			(16,538)	(16,538)
32	Structures And Improv	366			24,337	24,337
33	Mains - Cathodic Prot	367		719,643	1,346,040	2,065,683
34	Mains-Steel	367.1		1,148	417	1,564
35	Compressor Station Eq	368			1,854	1,854
36	Measuring And Reg	369		18,066	335,373	353,440
37	Other Equipment Stora	371			(9,910)	(9,910)
38	Total Transmission Plant		0	738,857	1,681,573	2,420,430
39						
40	**Distribution Plant A/D**					
41	Land & Land Rights	374		174,934	19,187	194,121
42	Rights-of-way	374.2		27,788	(105,049)	(77,261)
43	Structures & Improvem	375		54,394	(1,704)	52,690
44	Mains	376		44,097,123	780,632	44,877,755
45	Compressor Station Equip	377			0	0
46	Meas	378		1,703,494	8,256	1,711,750
47	Meas & Reg Station Eq	379		1,202,811	219	1,203,029
48	Meas	379.8			5,163	5,163
49	Services	380		20,074,078	1,851,127	21,925,205

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011
Accumulated Depreciation

Line No.	Description	Property Type	Liberty Div 79	Kansas Div 81	Southwest Div Div 86	Total Kansas
	(a)	(b)	(c)	(d)	(e)	(f)
50	Meters	381		7,230,388	372,156	7,602,543
51	Meter Installations	382		2,090,449	568,024	2,658,473
52	House Regulators	383		1,280,199	48,828	1,329,026
53	House Regulator Insta	384		200,420	(14,472)	185,948
54	Industrial Measuring	385		232,432	42,956	275,388
55	Other Equipment Distr	387		1,840	837	2,677
56	Total Distribution Plant		0	78,370,348	3,576,159	81,946,507
57						
58	**Direct General Plant A/D**					
59	Land & Land Rights	389		(2,883)		(2,883)
60	Struct & Improve Grp	390		270,043	10,255	280,298
61	Improvements Grp	390.3		730		730
62	Air Condition Eq Grp	390.4			5,242	5,242
63	Improve - Leased Grp	390.9		18,723	(4,219)	14,504
64	Office Furniture And	391		(212,786)	(66,582)	(279,368)
65	Office Machines	391.3		(11,143)	(12,209)	(23,352)
66	Transp Equip - Group	392		252,210	(12,158)	240,053
67	Stores Equipment	393		(6,352)	0	(6,352)
68	Tools & Shop Equip	394	3,261	638,163	64,133	705,557
69	Laboratory Equipment	395		587	3,056	3,643
70	Power Op Equip-Group	396		247,140	6,084	253,223
71	Ditchers	396.3		71,728	29,589	101,316
72	Backhoes	396.4		104,497	(8,906)	95,591
73	Welders	396.5		21,495		21,495
74	Communication Equipme	397		18,299	9,944	28,244
75	Communication Equip	397.1		(33,231)	(2,688)	(35,919)
76	Communication Equip	397.2		(6,323)		(6,323)
77	Miscellaneous Equipme	398		634,185	38	634,223
78	Other Tangible Equipm	399		19,376		19,376
79	Servers Hardware	399.1		2,716		2,716
80	Servers Software	399.2		15,363		15,363
81	Network Hardware	399.3		32,742		32,742
82	Mainframe Hardware	399.5		1,231		1,231
83	Pc Hardware	399.6		560,869	15,269	576,138
84	Oth Tang Prop - PC So	399.7		10,757		10,757
85	Application Software	399.8		48,898		48,898
86	Total Direct General Plant		3,261	2,697,034	36,849	2,737,144
87	Retirement Work In Progress	RWIP		(1,341,518)	(289,406)	(1,630,924)
88	RWIP from KS Admin Div 80	WP 5-5		0		0
89	Reconciling Items		0	3		3
90	**Total Kansas Direct Accum. Deprec.**		$ 3,813,137	$ 80,444,679	$ 5,005,175	$ 89,262,991
91						
92	General Accum Deprec Alloc from Share	WP 5-2				3,706,732
93	General Accum Deprec Alloc from Custo	WP 5-3				6,087,258
94	General Accum Deprec Alloc from CO/K	WP 5-4				770,252
95						
96	**Total KS Direct and Allocated Accum. Deprec.**					$ 99,827,232
97						
98	Source: See Relied Files 1a, 1b, 1c, 2c (Provided in response to DR 1)					

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011
O&M

Line	Acct. No.	Description	Per Books O&M	Adjustments: Reclass	Labor	Benefits	AGA Dues	Charitable Contr	Rate Case	Exp Rpts-KS	Exp Rpts-SSU	Pen/Post Ret	Adjusted O&M
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	752	Gas Wells Expenses	39,461	(39,461)									0
2	764	Maintenance of Field Lines	0										0
3	767	Maintenance of Purification equipment	0										0
4	815	Maps and Records	0										0
5	816	Wells Expense	651,456	39,461									690,917
6	819	Compressor Station Fuel and Power	112,899										112,899
7	824	Other Expenses	21,090										21,090
8	825	Storage Well Royalties	61,209										61,209
9	830	Storage-Maintenance Supervision & Engineering	174										174
10	831	Storage-Maintenance of structures & improvemer	117										117
11	832	Maintenance of reservoirs and wells	3,432										3,432
12	834	Maintenance of compressor station equipment	18,289										18,289
13	836	Processing-Maintenance of purification equipmer	16										16
14	841	Operation Labor and Expense	28,502										28,502
15	850	Operation supervision and engineering	0										0
16	853	Compressor station labor and expenses	0										0
17	854	Gas for Compressor Station fuel	0										0
18	856	Mains Expense	490										490
19	857	Measuring & Regulating Station Equipment	3,209										3,209
20	860	Rents	0										0
21	861	Maintenance Supervision & Engineering	55										55
22	870	Supervision & Engineering	554,485		212,613					(17,753)			749,345
23	871	Load Dispatching	8,487										8,487
24	871.1	Odorization	25,956										25,956
25	874	Mains & Service Expenses	2,984,797							(1,113)			2,983,684
26	875	Meas. & Reg. Sta. Expenses - General	71,802										71,802
27	877	Meas. & Reg. Sta. Expenses - City Gate	828										828
28	878	Meter & House Reg. Expenses	448,638										448,638
29	879	Customer Installations Expenses	105,042										105,042
30	880	Other Expenses	325,159										325,159
31	881	Rents	91,123										91,123
32	885	Supervision & Engineering	242,085							(2,120)			239,966
33	886	Structures - Improvements	8,278										8,278
34	887	Mains	165,418							(554)			164,864
35	888	Maintenance of Compressor Station Equipment	0										0
36	889	Meas. & Reg. Sta. Equip. - General	102,374							(12)			102,362
37	890	Maintenance of Meas. & Reg. Sta Equip - Industr	462										462
38	892	Services	18,297										18,297
39	893	Meter & House Regulators	7,993										7,993
40	894	Maintenance of other equipment	129										129

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011
O&M

Line	Acct. No.	Description	Per Books O&M	Adjustments: Reclass	Labor	Benefits	AGA Dues	Charitable Contr	Rate Case	Exp Rpts-KS	Exp Rpts-SSU	Pen/Post Ret	Adjusted O&M
41	901	Supervision	54,396							(1,306)			53,090
42	902	Meter Reading Expenses	810,278							(110)			810,168
43	903	Customer Records & Collection Expenses	69,524										69,524
44	904	Uncollectible Accounts	662,680										662,680
45	905	Misc. Customer Accounts Expenses	8,608							(2,930)			5,678
46	907	Supervision	1,065										1,065
47	908	Customer Assistance Expenses	50										50
48	909	Informational Advertising	4,851										4,851
49	910	Miscellaneous Customer Service Expenses	429										429
50	911	Supervision	160										160
51	912	Demonstrating and Selling	2,232							(2,236)			(4)
52	916	Misc sales expenses	925										925
53	920	Administrative & general salaries	231,876										231,876
54	921	Office Supplies & Expense	18,360							(3,761)			14,600
55	922	Administrative Expense Transfer - Credit	8,472,671							(17,940)	(14,529)		8,440,201
56	923	Outside services employed	3,491										3,491
57	924	Property Insurance	109,159										109,159
58	925	Injuries and Damages	10,504										10,504
59	926	Employee Welfare and Pensions	1,513,913			82,670				(1,356)		69,534	1,664,760
60	928	Regulatory Commission Expense	0						210,000				210,000
61	930.2	Miscellaneous General Expense	11,373				(7,203)	78,707		(4,000)			78,878
62	931	Rents	19,995										19,995
63	932	Maintenance of General Plant	0										0
64													
65		Total	18,108,293	0	212,613	82,670	(7,203)	78,707	210,000	(55,191)	(14,529)		18,684,894

Line	Adjustments to O & M Expenses	Amount
66	Labor	212,613
67	Benefits	82,670
68	AGA Dues	(7,203)
69	50% of Charitable Contributions	78,707
70	Rate Case Expense	210,000
71	Expense Report Adjustment	(69,720)
72	Pen/Post Ret Benefits	69,534
73	Total Adjustments	576,601
74		
75	Total Adjusted O & M Expenses	$18,684,894

Data is obtained from Section 9, wp9-1 of the revenue requirements model

Atmos Energy Corporation - Kansas
Section 14 - Class Cost Allocation Study
For test year ended September 30, 2011
Volumes

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	Tot. Kansas	Sales Resid.	Sales Com/PA	Sales Schools	Sales Indus/Inter	Sales Irrigation	Transport Firm	Transport Interr.	Transport Firm Schools
1	Peak Month (February 2011) Ccf									
2	As adjusted	33,864,750	22,134,000	6,981,479	164,676	204,466	112,199	2,618,410	1,297,060	352,460
3										
4	Annual Delivery or Thru-put Ccf									
5	As adjusted	170,174,970	100,475,009	32,441,250	652,838	1,125,665	7,457,811	14,431,833	12,180,190	1,410,374
6										
7	Winter Volume Ccf excl. Transp. [1]									
8	As adjusted	116,837,006	86,744,002	26,932,215	609,090	870,699	1,681,000	-	-	-
9										
10	Annual Interruptible Sales Ccf					602,299				
11										
12	Peak Month Interuptible Sales Ccf					102,614				

[1] November through April
[2] Data from Section 17 and File "Adjusted TY volume by month.xls"
[3] The class for Transport Schools Interruptible was eliminated since there are no longer any such customers.

Atmos Energy Corporation
Kansas Distribution System
Summary of Other Rate Base Components
Test Year Twelve Months Ended September 30, 2011

Line No.	Description	Source	Total Kansas Juris. Direct & Alloc Amount	Total Kansas Juris. Adjusted Amount
	(a)	(b)	(c)	(d)
1	Construction Work in Progress	WP 14-1-1 / WP 14-1	$ 6,821,140	$ 18,782,485
2				
3	Rate Base Deductions:			
4	Customer Advances for Construction [1]	WP 14-2	$ (1,065,228)	$ (1,065,228)
5	Customer Deposits [1]	WP 14-3	(2,455,902)	(2,455,902)
6	Accumulated Deferred Income Tax	WP 14-4	(38,767,208)	(35,687,906)
7				
8	Total		$ (35,467,198)	$ (20,426,551)
9				
10	Note:			
11	[1] 13 month average.			

Atmos Energy Corporation
Kansas Distribution System
Computation of Work in Progress
As of September 30, 2011

Line No.	Description	Source	Total KS Juris	
	(a)	(b)	(c)	
1	Adjustments to CWIP			
2	Projects to close by 3/31/2012:			
3	Pflumm Line	WP 14-1-2	$ 2,699,459	
4	Non Pflumm Line	WP 14-1-2	2,428,742	
5	Projects related to Pflumm Line - Budget FY 2012	WP 14-1-2	8,393,421	
6	SSU projects closing by 3/31/2012	WP 14-1-2	378,854	
7	Kansas projects closing by 3/31/2012	WP 14-1-2	4,882,008	
8	Total Adjusted CWIP		$ 18,782,485	
9				
10	CWIP - Per Book	WP 14-1-1	$ 6,821,140	
11				
12	Adjustment to CWIP		$ 11,961,346	**RB-1**

Atmos Energy Corporation
Kansas Distribution Systems
Construction Work in Progress Acct 107
As of September 30, 2011

Line No.	Description	Book Amounts	Alloc %	Kansas Juris
	(a)	(b)	(c)	(d)
	Direct			
1	Liberty Div 79	$ 18,554		$ 18,554
2	Kansas Div 81	4,949,733		4,949,733
3	Southwest Div 86	101,636		101,636
4	Kansas Admin Div 80	58,279	100.00%	58,279
5				
6	Allocated			
7	Shared Services Div 02	$ 12,470,095	4.07%	$ 507,533
8	Customer Support Div 12	27,106,673	4.17%	1,130,348
9	CO/KS General Office Div 30	94,535	58.24%	55,057
10				
11	Total	$ 44,799,504		$ 6,821,140

Source: See Relied files 1a through 1g

WP 14-1-2
RB-1

Atmos Energy Corporation
Kansas Distribution Systems
CWIP Adjustment Acct 107
For the test year ended September 30, 2011

Line No.	Description		Kansas Div 79, 80 & 81	SSU Div 02	CSC DIV 12	Alloc. Rate	Kansas Jurisdictional
	(a)		(b)	(c)	(d)	(e)	(f)
1	Add for Pflumm Line:						
2	060.19376-Open CWIP relating to Pflumm Line Project		$ 2,699,459				$ 2,699,459
3	Add for non Pflumm Line:						
4	Projects not related to Pflumm Line Project closing in Spring 2012		2,428,742				2,428,742
5	Add for budgeted Pflumm Line:						
6	Budgeted 2012 spending related to Pflumm Line Project		8,393,421				8,393,421
7	Add for Kansas projects:						
8	Projects closing by 3/31/2012	[1]	4,882,008				4,882,008
9	Add for SSU projects:						
10	Projects closing by 3/31/2012	[1]		8,451,778		4.07%	343,987
11	Projects closing by 3/31/2012	[1]			836,140	4.17%	34,867
12							
13	Total Adjusted CWIP						$ 18,782,485
14							
15	Note:						
16	[1] Amounts shown above will close to plant by March 31, 2012						

Atmos Energy Corporation
Kansas Distribution System
Customer Advance for Construction 252
Thirteen Month Average Balance Ended September 30, 2011

Line No.	Month	Kansas Div DIV 81	SW KS Div DIV 86	Total
	(a)	(b)	(c)	(d)
1	Sep-10	$ (1,024,315)	$ (40,914)	$ (1,065,228)
2	Oct-10	(1,024,315)	(40,914)	(1,065,228)
3	Nov-10	(1,024,315)	(40,914)	(1,065,228)
4	Dec-10	(1,024,315)	(40,914)	(1,065,228)
5	Jan-11	(1,024,315)	(40,914)	(1,065,228)
6	Feb-11	(1,024,315)	(40,914)	(1,065,228)
7	Mar-11	(1,024,315)	(40,914)	(1,065,228)
8	Apr-11	(1,024,315)	(40,914)	(1,065,228)
9	May-11	(1,024,315)	(40,914)	(1,065,228)
10	Jun-11	(1,024,315)	(40,914)	(1,065,228)
11	Jul-11	(1,024,315)	(40,914)	(1,065,228)
12	Aug-11	(1,024,315)	(40,914)	(1,065,228)
13	Sep-11	(1,024,315)	(40,914)	(1,065,228)
14				
15	13 Month Average	$ (1,024,315)	$ (40,914)	$ (1,065,228)

Source: See Relied files 1b and 1c

Atmos Energy Corporation
Kansas Distribution System
Customer Deposits 235
Thirteen Month Average Balance Ended September 30, 2011

Line No.	Month	CoKs GO DIV 30	Kansas Div DIV 81	SW KS Div DIV 86	Total
	(a)	(b)	(c)	(d)	(e)
1	Sep-10	$ (17,804)	$ (2,388,867)	$ (138,236)	$ (2,544,906)
2	Oct-10	(17,804)	(2,396,856)	(139,019)	(2,553,678)
3	Nov-10	(17,804)	(2,447,265)	(139,954)	(2,605,022)
4	Dec-10	(17,804)	(2,447,698)	(140,314)	(2,605,815)
5	Jan-11	(17,804)	(2,441,166)	(140,203)	(2,599,172)
6	Feb-11	(17,804)	(2,412,314)	(140,368)	(2,570,485)
7	Mar-11	(17,804)	(2,376,964)	(137,549)	(2,532,316)
8	Apr-11	(17,804)	(2,315,446)	(136,127)	(2,469,376)
9	May-11	(17,804)	(2,275,429)	(133,251)	(2,426,483)
10	Jun-11	(17,804)	(2,235,544)	(132,917)	(2,386,265)
11	Jul-11	(17,804)	(2,209,074)	(132,902)	(2,359,779)
12	Aug-11	(17,804)	(2,045,951)	(127,167)	(2,190,922)
13	Sep-11	(17,804)	(2,034,525)	(126,832)	(2,179,161)
14					
15	13 Month Average	$ (17,804)	$ (2,309,777)	$ (135,756)	$ (2,463,337)
16					
17	Allocation Rate	58.24%			
18	Total KS	$ (10,369)	$ (2,309,777)	$ (135,756)	$ (2,455,902)

Source: See Relied files 1b, 1c and 1f

Atmos Energy Corporation
Kansas Distribution Systems
ADIT accts 1900, 2550, 2820, 2830
Balance as of September 30, 2011

Line No.	Description	1900	2550	2820	2830	Per Book Total	alloc %	Kansas Juris	Source
			Account # Numbers						
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Direct								
1	Liberty Div 79	$ -	$ -	$ -	$ -	$ -		$ -	
2	Kansas Div 81	(2,109,270)	0	(45,010,880)	(485,991)	(47,606,141)		($47,606,141)	
3	Southwest Div 86	0	0	0	0	0		0	
4									
5	Allocated								
6	Shared Services Div 02	$132,158,420	$ -	$ (17,229,565)	$ 2,161,090	$117,089,946	4.07%	$ 4,765,561	
7	Customer Support Div 12	(1,376,517)		(13,608,488)	(944,023)	(15,929,028)	4.17%	(664,240)	
8	CO/KS General Office Div 30	8,494,106	(278)	(316,907)	(42,282)	8,134,638	58.24%	4,737,613	
9									
10	**Total Unadjusted**							($38,767,208)	
11									
12	Adjustments from WP 14-1-1					Adjustments			
13	Liberty Div 79					$ -			WP 14-4-1 ADIT AD
14	Kansas Div 81					(156,811)			WP 14-4-1 ADIT AD
15	Southwest Div 86					0			WP 14-4-1 ADIT AD
16									
17	Allocated								
18	Shared Services Div 02					$ (71,805,664)			WP 14-4-1 ADIT AD
19	Customer Support Div 12					0			
20	CO/KS General Office Div 30					0			WP 14-4-1 ADIT AD
21									
22	Direct with Adjustments					Per Book with Adjustments			
23	Liberty Div 79					$ -		$0	
24	Kansas Div 81					(47,449,330)		($47,449,330)	
25	Southwest Div 86					0		$0	
26									
27	Allocated with Adjustments								
28	Shared Services Div 02					$188,895,610	4.07%	$ 7,688,051	
29	Customer Support Div 12					(15,929,028)	4.17%	(664,240)	
30	CO/KS General Office Div 30					8,134,638	58.24%	4,737,613	
31									
32	**Total Adjusted**							$ (35,687,906)	
33									
34	**Total Adjustment**							$ 3,079,302	**RB-2**

Source: See Relied files 1b, 1d, 1e and 1f Sect. 12 Allocations

Atmos Energy Corporation
Kansas Distribution Systems
ADIT
Adjustments as of September 30, 2011

Line No.	Description	SSU Div. 002	SSU Div. 012	CO/KS General Office	Kansas Div 81	Southwest Div 86
	(a)	(b)	(c)	(d)	(e)	(f)
1	Section 481(a) Cushion Gas	$ 556,809	$ -	$ -	$ -	$ -
2	Section 481(a) Line Pack Gas	67,557				
3	Regulatory Liability - Atmos 109	9,790				
4	Deferred Gas Costs	0			1,333,196	
5	Over Recoveries of PGA				(1,757,009)	
6	PGA - Amended Item					
7	FD - NOL Credit Carryforward - Non Reg	(194,703,517)				
8						
9	Total	$ (194,069,361)	$ -	$ -	$ (423,812)	$ -
10						
11	ADIT Computation Rate	37%	37%	37%	37%	37%
12						
13	Adjustment	$ (71,805,664)	$ -	$ -	$ (156,811)	$ -

Source: See Relied File 14-4 ADIT
\\Dfw1wn18\shsr_workgroups\CO-KS Div Rate Case\2011 Kansas Rate Case\Model\Relied Upons\Relied 14-4 (ADIT).xls

Section 14C
IS-13

Atmos Energy Corporation
Kansas Distribution System
Computation of Interest on Customer Deposits
For the test year ended September 30, 2011

Line No.	Description	Reference		Total Kansas
	(a)	(b)		(c)
1	Thirteen Month Average Customer Deposits	Section 14A	$	2,455,902
2				
3	KCC Approved Interest Rate Cal Yr 2012			0.12%
4				
5	Interest on Customer Deposits		$	2,947
6				
7	Test Year Interest on Customer Deposits		$	11,995
8				
9	Total Adjustment to Interest on Customer Deposits		$	(9,048) **IS-13**

Source: See relied KCC approved interest rate for 2012

Depreciation Study

The current depreciation rates booked for the assets in the Colorado/Kansas Business Unit office, which is located in Denver, CO, were approved in the Company's recent Colorado Rate Case Docket No. 09AL-507G. The depreciation study that supports the business unit depreciation rates can be found in Attachment 1 in response to Staff data request 1-08.

Not Applicable

Section 16

Audited Financial Statements

See Section 13

Atmos Energy Corporation
Kansas Distribution Systems
Summary of Revenue at Present and Proposed Rates
Twelve Months Ended September 30, 2011

Line No.	Description	Current Tariffs	Average Bills	Number of Bills	Volumes	IS-14 Adjustments to Bills	IS-14 Adjustments to Volumes	Existing WNA	Total # of Bills	Total Adjusted Volumes	Present Facilities Charge	Present Commodity Rates	Present Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**Kansas - 081 Div**												
2	Residential Sales Service (910)	910	113,862	1,366,349	97,446,713			(232,480)	1,366,349	97,214,233	$15.50	$0.12953	$ 33,770,569
3	Commercial Sales Service (915)	915	8,846	106,146	27,933,664	6	9,900	(64,658)	106,152	27,878,906	37.00	0.12953	7,538,779
4	Public Authority Sales Service (915)	915	341	4,089	1,266,935			(1,296)	4,089	1,265,640	37.00	0.12953	315,231
5	Industrial Sales Service (930)	930	18	211	521,301				211	521,301	70.00	0.12953	82,294
6	School Sales Service (920)	920	64	772	565,077				772	565,077	37.00	0.12953	101,758
7	School Sales Service (920)	920	18	213	87,761				213	87,761	37.00	0.12953	19,249
8	Small Generator Sales Service (940)	940	69	823	2,065				823	2,065	37.50	0.15000	31,172
9	Large Industrial Sales Serv - Interruptible (955) <20,001	955	2	24	343,565				24	343,565	275.00	0.07140	31,131
10	>20,000				258,734					258,734		0.06340	16,404
11	Subtotal			1,478,627	128,425,816	6	9,900	(298,434)	1,478,633	128,137,282			$41,906,587
12													
13	Interruptible Transportation Serv - Industrial (IT900) <20,001	IT 900	39	472	12,173,696		0		472	12,173,696	$275.00	$0.07140	$ 999,002
14	>20,000	IT 900			6,494		0			6,494		0.06340	412
15	Firm Transportation Serv Commercial (FT-900)	(FT-900)	255	3,063	12,726,703	(10)	(13,290)		3,053	12,713,413	70.00	0.12953	1,860,478
16													
17	Special Contract 1 - Interruptible Transportation <20,001		1	12	1,214,040				12	1,214,040	275.00	0.02000	27,581
18	>20,000				0					0		0.01200	0
19	Special Contract 2 - Ind Interruptible Transportation		1	12	221,930				12	221,930	275.00	0.12953	32,047
20	School Transportation Service (920)	920	56	675	700,714	67	709,660		742	1,410,374	70.00	0.12953	234,626
21											70.00	0.12953	0
22	Interruptible Ind Trans Serv -Special Contract (IT900)	(IT900)	8	96	32,126,540				96	32,126,540	275.00	0.01250	427,982
23	Subtotal Transportation			4,330	59,170,117	57	696,370	0	4,387	59,866,487			$3,582,128
24													
25	Kansas Other Revenues Adjusted												994,986
26													
27	Kansas (081) Total Revenues												$ 46,483,701
28													
29	**Southwest - 086 Div**												
30	Residential Sales Service (910)	910	4,007	48,087	3,262,865			(2,089)	48,087	3,260,776	$15.50	$0.12953	$ 1,167,717
31	Commercial Sales Service (915)	915	487	5,846	1,216,598			(414)	5,846	1,216,185	37.00	0.12953	373,834
32	Public Authority Sales Service (915)	915	134	1,610	901,154			(553)	1,610	900,601	37.00	0.12953	176,225
33	School Sales Service (920)	920									37.00	0.12953	0
34	Irrigation Engine Sales Service (965)	965	272	3,262	7,457,811				3,262	7,457,811	49.00	0.08045	759,819
35	Commercial Agricultural Sales Service (915)	915	16	193	1,179,918				193	1,179,918	37.00	0.12953	159,976
36	Subtotal			58,998	14,018,347	0	0	(3,056)	58,998	14,015,291			$2,637,571
37													
38	Special Contract 1 - Transportation		0	0	1,803,520				0	1,803,520	$0.00	$0.04200	$ 75,748
39	Firm Transportation Serv - Industrial (FT900) 1	(FT900)	4	52	672,310	32	589,350		84	1,261,660	70.00	0.12953	169,303
40	Firm Transportation Serv - Industrial (FT900) 2	(FT900)	2	24	456,760				24	456,760	70.00	0.12953	60,844
41	Subtotal Transportation			76	2,932,590	32	589,350	0	108	3,521,940			305,895
42													
43	Southwest Other Revenues Adjusted												$105,150
44													
45	Total Southwest (086) Kansas Margin												$3,048,616
46													
47	Total Sales Margin								1,537,631				$ 44,544,158
48													
49	Total Transportation Margin								4,495				$ 3,888,023
50													
51	Total Other Revenues Adjusted												$ 1,100,136
52													
53	Total Kansas Margin												$ 49,532,317

Atmos Energy Corporation
WNA Volume Adjustment
Twelve Months ended September 2011

Line No.	Description	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Adjustment WNA Volumes	Commodity Rate	Adjustment WNA Volumes	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
1	**UCG - Kansas - 081 Div**																
2	Residential Sales Service (910)	73,350	129,383	40,749	(125,843)	(172,095)	(112,319)	9,508	(12,205)	(54,984)	6,791	3,825	(18,641)	(232,480)	0.12953	$ (30,113)	
3	Commercial Sales Service (915)	17,735	34,495	15,121	(33,181)	(48,720)	(33,594)	1,961	275	(16,797)	1,965	860	(4,778)	(64,658)	0.12953	(8,375)	
4	Public Authority Sales Service (915)	1,501	2,071	979	(973)	(2,592)	(2,236)	461	340	(493)	157	73	(585)	(1,296)	0.12953	(168)	
5	Division 81 Total	92,585	165,950	56,849	(159,996)	(223,407)	(148,148)	11,931	(11,590)	(72,274)	8,912	4,758	(24,004)	(298,434)		$ (38,656)	
6																	
7	**UCG - Kansas - 086 Div**																
8	Residential Sales Service (910)	2,487	2,067	719	1,307	(4,195)	(6,412)	231	2,493	(922)	613	40	(517)	(2,089)	0.12953	$ (271)	
9	Commercial Sales Service (915)	921	797	362	541	(1,498)	(2,323)	143	935	(330)	218	16	(197)	(414)	0.12953	(54)	
10	Public Authority Sales Service (915)	713	596	206	388	(1,200)	(1,839)	59	743	(265)	177	11	(143)	(553)	0.12953	(72)	
11	Division 86 Total	4,122	3,459	1,287	2,237	(6,893)	(10,573)	433	4,171	(1,517)	1,008	67	(857)	(3,056)		$ (396)	
12	Division 81 & 86 Totals	96,707	169,409	58,136	(157,759)	(230,300)	(158,721)	12,363	(7,419)	(73,791)	9,921	4,825	(24,860)	(301,489)		$ (39,052)	IS-14

Atmos Energy Corporation
Kansas Operations
Other Revenues Adjusted

Line No.	Description (a)	Div 81 (b)	Div 86 (c)	Total (d)	
1	4870	$316,800	$29,995	$346,794	
2	4880	88,117	4,516	92,633	
3	4950	590,070	70,639	660,709	
4					
5	Total Other Revenues	$994,986	$105,150	$1,100,136	Section 17
6					
7	Less: FY 2011 Ad Valorem Surcharge	$594,236	$70,639	$664,875	
8	Plus: 2012 Ad Valorem Surcharge	$756,868	$89,972	$846,840	**Note 1**
9					
10	Other Revenues with New Surcharge	$1,157,618	$124,483	$1,282,101	
11	Changes in Proposed Svc Charges	$238,325	$10,890	$249,215	
12	Prop Other Revenues w/o Surcharge	$639,075	$45,401	$684,475	Section 17
13					
14	Per Book Ad Valorem Removed in RD	($594,236)	($70,639)	($664,875)	**Note 2**
15					
16					
17	2011 Ad Valorem Surcharge Detail by Month				
18					
19		Div 81	Div 86		
20	October	$ 8,109	$ 2,055		
21	November	17,670	2,634		
22	December	50,929	3,121		
23	January	134,278	5,916		
24	February	144,135	5,949		
25	March	98,714	7,022		
26	April	56,521	8,157		
27	May	30,673	6,595		
28	June	16,889	6,906		
29	July	12,279	8,534		
30	August	11,355	7,900		
31	September	12,685	5,849		
32	**12 months Ending September**	**$ 594,236**	**$ 70,639**		
33					

34 Notes:
35 1. 2010 Ad Valorem Surcharge is not reflected in other revenues because it is a
36 non-permanent rate, subject to annual reconciliation. The Company's base rates
37 are designed to recover the of Cost of Service reflected in Section 3 independent
38 of what the Ad Valorem surcharge rate is established at in the future.
39 2. The removal of per books Ad Valorem Surcharge is reflected in rate design only
40 to allow the deficiency to reflect the amount of additional revenue required
41 in base rates going forward.

Atmos Energy Corporation
Kansas Operations
Industrial Account Adjustments

Line No	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Firm Transportation Serv Commercial (FT-900)**						
2	Adjust per book volumes and counts for 3 meters. 2 meters switched to sales in January,						
3	the 3rd is out of business as of February.						
4		Per Book	Per Book	Revised	Revised	Adjustment	Adjustment
5		Count	Volume	Count	Volume	Count	Volume
6	October	3	1,170	0	0	(3)	(1,170)
7	November	3	2,850	0	0	(3)	(2,850)
8	December	3	8,550	0	0	(3)	(8,550)
9	January	1	720	0	0	(1)	(720)
10	February	0	0	0	0	0	0
11	March	0	0	0	0	0	0
12	April	0	0	0	0	0	0
13	May	0	0	0	0	0	0
14	June	0	0	0	0	0	0
15	July	0	0	0	0	0	0
16	August	0	0	0	0	0	0
17	September	0	0	0	0	0	0
18	Total	10	13,290	0	0	(10)	(13,290)
19	Current Rate					$70.00	$0.12953
20	$ Value of Adjustment					($700.00)	($1,721.45)
21							
22							
23	**Commercial Sales Service (915)**						
24	Adjust per book volumes and count for customer that switched from						
25	Firm Transportation Serv Commercial (FT-900) to Commercial Sales.						
26		Per Book	Per Book	Revised	Revised	Adjustment	Adjustment
27		Count	Volume	Count	Volume	Count	Volume
28	October	0	0	2	320	2	320
29	November	0	0	2	1,780	2	1,780
30	December	0	0	2	7,800	2	7,800
31	January	0	0	0	0	0	0
32	February	0	0	0	0	0	0
33	March	0	0	0	0	0	0
34	April	0	0	0	0	0	0
35	May	0	0	0	0	0	0
36	June	0	0	0	0	0	0
37	July	0	0	0	0	0	0
38	August	0	0	0	0	0	0
39	September	0	0	0	0	0	0
40	Total	0	0	6	9,900	6	9,900
41	Current Rate					$37.00	$0.12953
42	$ Value of Adjustment					$222.00	$1,282.35
43							

School Transportation Service Post '95 (920)

Adjust per book volumes for new customers

	Per Book Count	Per Book Volume	Revised Count	Revised Volume	Adjustment Count	Adjustment Volume
October	0	0	7	5,450	7	5,450
November	0	0	7	34,640	7	34,640
December	0	0	8	117,410	8	117,410
January	0	0	8	145,310	8	145,310
February	0	0	8	177,620	8	177,620
March	0	0	8	140,980	8	140,980
April	0	0	8	63,620	8	63,620
May	0	0	8	21,440	8	21,440
June	4	830	7	3,740	3	2,910
July	6	250	7	530	1	280
August	7	420	8	420	1	0
September	7	680	7	680	0	0
Total	24	2,180	91	711,840	67	709,660
Current Rate					$70.00	$0.12953
$ Value of Adjustment					$4,690.00	$91,922.26

Firm Transportation Serv - Industrial (FT900)

Adjust per book volumes for new customers

	Per Book Count	Per Book Volume	Revised Count	Revised Volume	Adjustment Count	Adjustment Volume
October	0	0	4	77,500	4	77,500
November	0	0	4	77,500	4	77,500
December	0	0	4	77,500	4	77,500
January	0	0	4	77,500	4	77,500
February	0	0	4	77,500	4	77,500
March	0	0	4	77,500	4	77,500
April	0	0	4	77,500	4	77,500
May	0	0	4	77,500	4	77,500
June	4	99,080	4	77,500	0	(21,580)
July	4	84,370	4	77,500	0	(6,870)
August	4	81,530	4	77,500	0	(4,030)
September	4	75,670	4	77,500	0	1,830
Total	16	340,650	48	930,000	32	589,350
Current Rate					$70.00	$0.12953
$ Value of Adjustment					$2,240.00	$76,338.51
				Total Adjs	$6,230.00	$166,539.31

IS-14

Atmos Energy Corporation
Kansas Distribution Systems
Summary of Revenue at Present and Proposed Rates
Twelve Months Ended September 30, 2011

Line No.	Description	Current Tariffs	Average Bills	Number of Bills	Volumes	Adjustments to Bills	Adjustments to Volumes	Existing WNA	Total # of Bills	Total Adjusted Volumes	Present Facilities Charge	Present Commodity Rates	Present Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(j)	(h)	(l)	(m)	(n)	(o)
1	**Kansas - 081 Div**												
2	Residential Sales Service (910)	910	113,862	1,366,349	97,446,713			(232,480)	1,366,349	97,214,233	$15.50	$0.12953	$ 33,770,569
3	Commercial Sales Service (915)	915	8,846	106,146	27,933,664	6	9,900	(64,658)	106,152	27,878,906	37.00	0.12953	7,538,779
4	Public Authority Sales Service (915)	915	341	4,089	1,266,935			(1,296)	4,089	1,265,640	37.00	0.12953	315,231
5	Industrial Sales Service (930)	930	18	211	521,301				211	521,301	70.00	0.12953	82,294
6	School Sales Service (920)	920	64	772	565,077				772	565,077	37.00	0.12953	101,758
7	School Sales Service (920)	920	18	213	87,761				213	87,761	37.00	0.12953	19,249
8	Small Generator Sales Service (940)	940	69	823	2,065				823	2,065	37.50	0.15000	31,172
9	Large Industrial Sales Serv - Interruptible (955) <20,001	955	2	24	343,565				24	343,565	275.00	0.07140	31,131
10	>20,000				258,734					258,734		0.06340	16,404
11	Subtotal			1,478,627	128,425,816	6	9,900	(298,434)	1,478,633	128,137,282			$41,906,587
12													
13	Interruptible Transportation Serv - Industrial (IT900) <20,001	IT 900	39	472	12,173,696		0		472	12,173,696	$275.00	$0.07140	$ 999,002
14	>20,000	IT 900			6,494		0			6,494		0.06340	412
15	Firm Transportation Serv Commercial (FT-900)	(FT-900)	255	3,063	12,726,703	(10)	(13,290)		3,053	12,713,413	70.00	0.12953	1,860,478
16													
17	Special Contract 1 - Interruptible Transportation <20,001		1	12	1,214,040				12	1,214,040	275.00	0.02000	27,581
18	>20,000				0				0	0		0.01200	0
19	Special Contract 2 - Ind Interruptible Transportation		1	12	221,930				12	221,930	275.00	0.12953	32,047
20	School Transportation Service Post '95 (920)	920	56	675	700,714	67	709,660		742	1,410,374	70.00	0.12953	234,626
21		(FT900)							0	0	70.00	0.12953	0
22	Interruptible Ind Trans Serv -Special Contract (IT900)	(IT900)	8	96	32,126,540				96	32,126,540	275.00	0.01250	427,982
23	Subtotal Transportation			4,330	59,170,117	57	696,370	0	4,387	59,866,487			$3,582,128
24													
25	Kansas Other Revenues Adjusted												994,986
26													
27	Kansas (081) Total Revenues												$ 46,483,701
28													
29	**Southwest - 086 Div**												
30	Residential Sales Service (910)	910	4,007	48,087	3,262,865			(2,089)	48,087	3,260,776	$15.50	$0.12953	$ 1,167,717
31	Commercial Sales Service (915)	915	487	5,846	1,216,598			(414)	5,846	1,216,185	37.00	0.12953	373,834
32	Public Authority Sales Service (915)	915	134	1,610	901,154			(553)	1,610	900,601	37.00	0.12953	176,225
33	School Sales Service (920)	920							0	0	37.00	0.12953	0
34	Irrigation Engine Sales Service (965)	965	272	3,262	7,457,811				3,262	7,457,811	49.00	0.08045	759,819
35	Commercial Agricultural Sales Service (915)	915	16	193	1,179,918				193	1,179,918	37.00	0.12953	159,976
36	Subtotal			58,998	14,018,347	0	0	(3,056)	58,998	14,015,291			$2,637,571
37													
38	Special Contract 1 - Transportation		0	0	1,803,520				0	1,803,520	$0.00	$0.04200	$ 75,748
39	Firm Transportation Serv - Industrial (FT900) 1	(FT900)	4	52	672,310	32	589,350		84	1,261,660	70.00	0.12953	169,303
40	Firm Transportation Serv - Industrial (FT900) 2	(FT900)	2	24	456,760				24	456,760	70.00	0.12953	60,844
41	Subtotal Transportation			76	2,932,590	32	589,350	0	108	3,521,940			305,895
42													
43	Southwest Other Revenues Adjusted												105,150
44													
45	Total Southwest (086) Kansas Margin												$3,048,616
46													
47	Total Sales Margin												$ 44,544,158
48													
49	Total Transportation Margin												$ 3,888,023
50													
51	Total Other Revenues Adjusted												$ 1,100,136
52													
53	Total Kansas Margin												$ 49,532,317
54													

Atmos Energy Corporation
Kansas Distribution Systems
Summary of Revenue at Present and Proposed Rates
Twelve Months Ended September 30, 2011

Line No.	Description (a)	Current Tariffs (b)	Average Bills (c)	Number of Bills (d)	Volumes (e)	Adjustments to Bills (f)	Adjustments to Volumes (g)	Existing WNA (j)	Total # of Bills (h)	Total Adjusted Volumes (l)	Present Facilities Charge (m)	Present Commodity Rates (n)	Present Revenue (o)
1	**Kansas - 081 Div**												
2	Residential Sales Service (910)	910	113,862	1,366,349	97,446,713			(232,480)	1,366,349	97,214,233	$15.50	$0.12953	$ 33,770,569
3	Commercial Sales Service (915)	915	8,846	106,146	27,933,664	6	9,900	(64,658)	106,152	27,878,906	37.00	0.12953	7,538,779
4	Public Authority Sales Service (915)	915	341	4,089	1,266,935			(1,296)	4,089	1,265,640	37.00	0.12953	315,231
5	Industrial Sales Service (930)	930	18	211	521,301				211	521,301	70.00	0.12953	82,294
6	School Sales Service (920)	920	64	772	565,077				772	565,077	37.00	0.12953	101,758
7	School Sales Service (925)	925	18	213	87,761				213	87,761	37.00	0.12953	19,249
8	Small Generator Sales Service (940)	940	69	823	2,065				823	2,065	37.50	0.15000	31,172
9	Large Industrial Sales Serv - Interruptible (955) <20,001	955	2	24	343,565				24	343,565	275.00	0.07140	31,131
10	>20,000				258,734					258,734		0.06340	16,404
11	Subtotal			1,478,627	128,425,816	6	9,900	(298,434)	1,478,633	128,137,282			$41,906,587
12													
13	Interruptible Transportation Serv - Industrial (IT900) <20,001	IT 900	39	472	12,173,696		0		472	12,173,696	$275.00	$0.07140	$ 999,002
14	>20,000	IT 900			6,494		0			6,494		0.06340	412
15	Firm Transportation Serv Commercial (FT-900)	(FT-900)	255	3,063	12,726,703	(10)	(13,290)		3,053	12,713,413	70.00	0.12953	1,860,478
16													
17	Special Contract 1 - Interruptible Transportation <20,001		1	12	1,214,040				12	1,214,040	275.00	0.02000	27,581
18	>20,000				0				0	0		0.01200	0
19	Special Contract 2 - Ind Interruptible Transportation		1	12	221,930				12	221,930	275.00	0.12953	32,047
20	School Transportation Service Post '95 (920)	925	56	675	700,714	67	709,660		742	1,410,374	70.00	0.12953	234,626
21		(FT900)							0	0	70.00	0.12953	0
22	Interruptible Ind Trans Serv -Special Contract (IT900)	(IT900)	8	96	32,126,540				96	32,126,540	275.00	0.01250	427,982
23	Subtotal Transportation			4,330	59,170,117	57	696,370	0	4,387	59,866,487			$3,582,128
24													
25	Kansas Other Revenues Adjusted												994,986
26													
27	Kansas (081) Total Revenues												$ 46,483,701
28													
29	**Southwest - 086 Div**												
30	Residential Sales Service (910)	910	4,007	48,087	3,262,865			(2,089)	48,087	3,260,776	$15.50	$0.12953	$ 1,167,717
31	Commercial Sales Service (915)	915	487	5,846	1,216,598			(414)	5,846	1,216,185	37.00	0.12953	373,834
32	Public Authority Sales Service (915)	915	134	1,610	901,154			(553)	1,610	900,601	37.00	0.12953	176,225
33	School Sales Service (920)	920							0	0	37.00	0.12953	0
34	Irrigation Engine Sales Service (965)	965	272	3,262	7,457,811				3,262	7,457,811	49.00	0.08045	759,819
35	Commercial Agricultural Sales Service (915)	915	16	193	1,179,918				193	1,179,918	37.00	0.12953	159,976
36	Subtotal			58,998	14,018,347	0	0	(3,056)	58,998	14,015,291			$2,637,571
37													
38	Special Contract 1 - Transportation		0	0	1,803,520				0	1,803,520	$0.00	$0.04200	$ 75,748
39	Firm Transportation Serv - Industrial (FT900) 1	(FT900)	4	52	672,310	32	589,350		84	1,261,660	70.00	0.12953	169,303
40	Firm Transportation Serv - Industrial (FT900) 2	(FT900)	2	24	456,760				24	456,760	70.00	0.12953	60,844
41	Subtotal Transportation			76	2,932,590	32	589,350	0	108	3,521,940			305,895
42													
43	Southwest Other Revenues Adjusted												105,150
44													
45	Total Southwest (086) Kansas Margin												$3,048,616
46													
47	Total Sales Margin												$ 44,544,158
48													
49	Total Transportation Margin												$ 3,888,023
50													
51	Total Other Revenues Adjusted												$ 1,100,136
52													
53	Total Kansas Margin												$ 49,532,317
54													

Atmos Energy Corporation
WNA Volume Adjustment

ıded September 30, 2011

Line No.	Description	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Adjustment WNA Volumes	Present Commodity Rate	Adjustment WNA Volumes
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	**UCG - Kansas - 081 Div**															
2	Residential Sales Service (910)	73,350	129,383	40,749	(125,843)	(172,095)	(112,319)	9,508	(12,205)	(54,984)	6,791	3,825	(18,641)	(232,480)	0.12953	$ (30,113)
3	Commercial Sales Service (915)	17,735	34,495	15,121	(33,181)	(48,720)	(33,594)	1,961	275	(16,797)	1,965	860	(4,778)	(64,658)	0.12953	(8,375)
4	Public Authority Sales Service (915)	1,501	2,071	979	(973)	(2,592)	(2,236)	461	340	(493)	157	73	(585)	(1,296)	0.12953	(168)
5	Division 81 Total	92,585	165,950	56,849	(159,996)	(223,407)	(148,148)	11,931	(11,590)	(72,274)	8,912	4,758	(24,004)	(298,434)		$ (38,656)
6																
7	**UCG - Kansas - 086 Div**															
8	Residential Sales Service (910)	2,487	2,067	719	1,307	(4,195)	(6,412)	231	2,493	(922)	613	40	(517)	(2,089)	0.12953	$ (271)
9	Commercial Sales Service (915)	921	797	362	541	(1,498)	(2,323)	143	935	(330)	218	16	(197)	(414)	0.12953	(54)
10	Public Authority Sales Service (915)	713	596	206	388	(1,200)	(1,839)	59	743	(265)	177	11	(143)	(553)	0.12953	(72)
11	Division 86 Total	4,122	3,459	1,287	2,237	(6,893)	(10,573)	433	4,171	(1,517)	1,008	67	(857)	(3,056)		$ (396)
12	Division 81 & 86 Totals	96,707	169,409	58,136	(157,759)	(230,300)	(158,721)	12,363	(7,419)	(73,791)	9,921	4,825	(24,860)	(301,489)		$ (39,052)

Atmos Energy Corporation
Kansas Operations
Other Revenues Adjusted

Line No.	Description		Div 81	Div 86	Total	Reference
	(a)		(b)	(c)	(d)	(e)
1		4870	$316,800	$29,995	$346,794	
2		4880	88,117	4,516	92,633	
3		4950	590,070	70,639	660,709	
4						
5	Total Other Revenues		$994,986	$105,150	$1,100,136	Section 17
6						
7	Less: FY 2011 Ad Valorem Surcharge		$594,236	$70,639	$664,875	
8	Plus: 2012 Ad Valorem Surcharge		$756,868	$89,972	$846,840	Note 1
9						
10	Other Revenues with New Surcharge		$1,157,618	$124,483	$1,282,101	
11	Changes in Proposed Svc Charges		$238,325	$10,890	$249,215	
12	Prop Other Revenues w/o Surcharge		$639,075	$45,401	$684,475	Section 17
13						
14	Per Book Ad Valorem Removed in RD		($594,236)	($70,639)	($664,875)	Note 2
15						
16						
17	2011 Ad Valorem Surcharge Detail by Month:					
18						
19			**Div 81**	**Div 86**		
20	October		$ 8,109	$ 2,055		
21	November		17,670	2,634		
22	December		50,929	3,121		
23	January		134,278	5,916		
24	February		144,135	5,949		
25	March		98,714	7,022		
26	April		56,521	8,157		
27	May		30,673	6,595		
28	June		16,889	6,906		
29	July		12,279	8,534		
30	August		11,355	7,900		
31	September		12,685	5,849		
32	**12 months Ending September**		$ 594,236	$ 70,639		

33
34 Notes:
35 1. 2010 Ad Valorem Surcharge is not reflected in other revenues because it is a
36 non-permanent rate, subject to annual reconciliation. The Company's base rates
37 are designed to recover the of Cost of Service reflected in Section 3 independent
38 of what the Ad Valorem surcharge rate is established at in the future.
39 2. The removal of per books Ad Valorem Surcharge is reflected in rate design only
40 to allow the deficiency to reflect the amount of additional revenue required
41 in base rates going forward.

Atmos Energy Corporation
Kansas Operations
Industrial Account Adjustments

Line No	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Firm Transportation Serv Commercial (FT-900)**						
2	Adjust per book volumes and counts for 3 meters. 2 meters switched to sales in January,						
3	the 3rd is out of business as of February.						
4							
5		Per Book	Per Book	Revised	Revised	Adjustment	Adjustment
6		Count	Volume	Count	Volume	Count	Volume
7	October	3	1,170	0	0	(3)	(1,170)
8	November	3	2,850	0	0	(3)	(2,850)
9	December	3	8,550	0	0	(3)	(8,550)
10	January	1	720	0	0	(1)	(720)
11	February	0	0	0	0	0	0
12	March	0	0	0	0	0	0
13	April	0	0	0	0	0	0
14	May	0	0	0	0	0	0
15	June	0	0	0	0	0	0
16	July	0	0	0	0	0	0
17	August	0	0	0	0	0	0
18	September	0	0	0	0	0	0
19	Total	10	13,290	0	0	(10)	(13,290)
20	Current Rate					$70.00	$0.12953
21	$ Value of Adjustment					($700.00)	($1,721.45)
22							
23							
24	**Commercial Sales Service (915)**						
25	Adjust per book volumes and count for customer that switched from						
26	Firm Transportation Serv Commercial (FT-900) to Commercial Sales.						
27							
28		Per Book	Per Book	Revised	Revised	Adjustment	Adjustment
29		Count	Volume	Count	Volume	Count	Volume
30	October	0	0	2	320	2	320
31	November	0	0	2	1,780	2	1,780
32	December	0	0	2	7,800	2	7,800
33	January	0	0	0	0	0	0
34	February	0	0	0	0	0	0
35	March	0	0	0	0	0	0
36	April	0	0	0	0	0	0
37	May	0	0	0	0	0	0
38	June	0	0	0	0	0	0
39	July	0	0	0	0	0	0
40	August	0	0	0	0	0	0
41	September	0	0	0	0	0	0
42	Total	0	0	6	9,900	6	9,900
43	Current Rate					$37.00	$0.12953
44	$ Value of Adjustment					$222.00	$1,282.35
45							

School Transportation Service Post '95 (920)

Adjust per book volumes for new customers

	Per Book Count	Per Book Volume	Revised Count	Revised Volume	Adjustment Count	Adjustment Volume
October	0	0	7	5,450	7	5,450
November	0	0	7	34,640	7	34,640
December	0	0	8	117,410	8	117,410
January	0	0	8	145,310	8	145,310
February	0	0	8	177,620	8	177,620
March	0	0	8	140,980	8	140,980
April	0	0	8	63,620	8	63,620
May	0	0	8	21,440	8	21,440
June	4	830	7	3,740	3	2,910
July	6	250	7	530	1	280
August	7	420	8	420	1	0
September	7	680	7	680	0	0
Total	24	2,180	91	711,840	67	709,660
Current Rate					$70.00	$0.12953
$ Value of Adjustment					$4,690.00	$91,922.26

Firm Transportation Serv - Industrial (FT900)

Adjust per book volumes for new customers

	Per Book Count	Per Book Volume	Revised Count	Revised Volume	Adjustment Count	Adjustment Volume
October	0	0	4	77,500	4	77,500
November	0	0	4	77,500	4	77,500
December	0	0	4	77,500	4	77,500
January	0	0	4	77,500	4	77,500
February	0	0	4	77,500	4	77,500
March	0	0	4	77,500	4	77,500
April	0	0	4	77,500	4	77,500
May	0	0	4	77,500	4	77,500
June	4	99,080	4	77,500	0	(21,580)
July	4	84,370	4	77,500	0	(6,870)
August	4	81,530	4	77,500	0	(4,030)
September	4	75,670	4	77,500	0	1,830
Total	16	340,650	48	930,000	32	589,350
Current Rate					$70.00	$0.12953
$ Value of Adjustment					$2,240.00	$76,338.51
				Total Adjs	$6,230.00	$166,539.32

Kansas Weather Normalization Adjustment Program
October-10

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,857	13.058	12	33	0.01072	134	207	0.00356	**1,167**	**901**
Anthony	Commercial Sales Service (915)	1.2953	248	25.945	12	33	0.02805	134	207	0.00721	**358**	**277**
Anthony	Public Authority Sales Service (915)	1.2953	32	80.597	12	33	0.05973	134	207	0.01473	**97**	**75**
Chanute	Residential Sales Service (910)	1.2953	6,514	12.48	19	46	0.00906	174	223	0.00493	**4,102**	**3,167**
Chanute	Commercial Sales Service (915)	1.2953	857	30.576	19	46	0.02223	174	223	0.00927	**1,171**	**904**
Chanute	Public Authority Sales Service (915)	1.2953	64	56.723	19	46	0.04786	174	223	0.0288	**224**	**173**
Council Grove Lake	Residential Sales Service (910)	1.2953	2,074	12.789	35	63	0.00772	198	287	0.00472	**1,709**	**1,320**
Council Grove Lake	Commercial Sales Service (915)	1.2953	257	134.495	35	63	0.02011	198	287	0.01758	**708**	**547**
Council Grove Lake	Public Authority Sales Service (915)	1.2953	51	53.63	35	63	0.04275	198	287	0.02167	**206**	**159**
Independence	Residential Sales Service (910)	1.2953	9,828	11.675	19	42	0.00856	186	200	0.00716	**3,782**	**2,920**
Independence	Commercial Sales Service (915)	1.2953	1,188	38.242	19	42	0.02598	186	200	0.02366	**1,429**	**1,103**
Independence	Public Authority Sales Service (915)	1.2953	0	NA	19	42	NA	186	200	NA	**NA**	
Lawrence	Residential Sales Service (910)	1.2953	5,717	15.468	24	43	0.00473	172	204	0.00742	**2,424**	**1,871**
Lawrence	Commercial Sales Service (915)	1.2953	332	49.593	24	43	0.01910	172	204	0.04689	**801**	**619**
Lawrence	Public Authority Sales Service (915)	1.2953	16	80.242	24	43	0.05811	172	204	0.07438	**72**	**56**
Leavenworth	Residential Sales Service (910)	1.2953	6,112	17.144	26	58	0.00987	186	265	0.00391	**4,946**	**3,818**
Leavenworth	Commercial Sales Service (915)	1.2953	378	127.58	26	58	0.04696	186	265	0.00575	**958**	**740**
Leavenworth	Public Authority Sales Service (915)	1.2953	20	26.2	26	58	0.06950	186	265	0.01399	**86**	**67**
Marion lake	Residential Sales Service (910)	1.2953	4,322	12.786	21	72	0.00804	183	293	0.00415	**4,851**	**3,745**
Marion lake	Commercial Sales Service (915)	1.2953	491	41.224	21	72	0.01698	183	293	0.0158	**1,656**	**1,279**
Marion lake	Public Authority Sales Service (915)	1.2953	118	231.02	21	72	0.03460	183	293	0.0481	**1,078**	**833**
Ness City	Residential Sales Service (910)	1.2953	962	15.522	15	53	0.01105	209	304	0.00144	**694**	**536**
Ness City	Commercial Sales Service (915)	1.2953	159	26.966	15	53	0.02183	209	304	0.00313	**232**	**179**
Ness City	Public Authority Sales Service (915)	1.2953	38	59.064	15	53	0.03854	209	304	0.01648	**149**	**115**
KC Downtown AP	Residential Sales Service (910)	1.2953	73,012	16.581	18	37	0.00959	133	217	0.00661	**69,742**	**53,843**
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,432	86.258	18	37	0.04406	133	217	0.02156	**15,203**	**11,737**
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	18	37	0.12163	133	217	0.06737	**31**	**24**
Sedan	Residential Sales Service (910)	1.2953	2,377	12.687	19	41	0.01034	145	211	0.00439	**1,592**	**1,229**
Sedan	Commercial Sales Service (915)	1.2953	328	57.523	19	41	0.04018	145	211	0.00283	**455**	**351**
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	19	41	NA	145	211	NA	**NA**	
Syracuse	Residential Sales Service (910)	1.2953	827	18.134	10	66	0.01075	251	322	0.00218	**811**	**626**
Syracuse	Commercial Sales Service (915)	1.2953	105	73.735	10	66	0.03565	251	322	0.0121	**388**	**300**
Syracuse	Public Authority Sales Service (915)	1.2953	42	64.034	10	66	0.06437	251	322	0.01166	**241**	**186**
Ulysses	Residential Sales Service (910)	1.2953	3,168	19.79	11	55	0.00990	234	280	0.0033	**2,410**	**1,861**
Ulysses	Commercial Sales Service (915)	1.2953	374	64.975	11	55	0.02846	234	280	0.00891	**805**	**622**
Ulysses	Public Authority Sales Service (915)	1.2953	92	200	11	55	0.09714	234	280	0.03167	**683**	**527**
											125,264	**96,707**

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	95,010	73,350
Commercial Sales Service (915)	22,972	17,735
Public Authority Sales Service (915)	1,944	1,501

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	3,221	2,487
Commercial Sales Service (915)	1,194	921
Public Authority Sales Service (915)	924	713
Total	125,264	96,707

Kansas Weather Normalization Adjustment Program
November-10

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month			Current Month			(Revenue/Excess)	Volume Adjustment
					Actual ADD	Normal ADD	HSF	Actual ADD	Normal ADD	HSF	Deficiency $	
Anthony	Residential Sales Service (910)	1.2953	1,860	13.058	134	207	0.01072	558	618	0.00356	2,400	1,853
Anthony	Commercial Sales Service (915)	1.2953	250	25.945	134	207	0.02805	558	618	0.00721	803	620
Anthony	Public Authority Sales Service (915)	1.2953	33	80.597	134	207	0.05973	558	618	0.01473	224	173
Chanute	Residential Sales Service (910)	1.2953	6,593	12.48	174	223	0.00906	490	598	0.00493	8,338	6,437
Chanute	Commercial Sales Service (915)	1.2953	870	30.576	174	223	0.02223	490	598	0.00927	2,356	1,819
Chanute	Public Authority Sales Service (915)	1.2953	65	56.723	174	223	0.04786	490	598	0.0288	459	355
Council Grove Lake	Residential Sales Service (910)	1.2953	2,082	12.789	198	287	0.00772	609	688	0.00472	2,859	2,207
Council Grove Lake	Commercial Sales Service (915)	1.2953	261	134.495	198	287	0.02011	609	688	0.01758	1,075	830
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	198	287	0.04275	609	688	0.02167	350	270
Independence	Residential Sales Service (910)	1.2953	9,902	11.675	186	200	0.00856	494	568	0.00716	8,333	6,433
Independence	Commercial Sales Service (915)	1.2953	1,191	38.242	186	200	0.02598	494	568	0.02366	3,262	2,518
Independence	Public Authority Sales Service (915)	1.2953	0	NA	186	200	NA	494	568	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	5,756	15.468	172	204	0.00473	562	604	0.00742	3,452	2,665
Lawrence	Commercial Sales Service (915)	1.2953	342	49.593	172	204	0.01910	562	604	0.04689	1,143	883
Lawrence	Public Authority Sales Service (915)	1.2953	16	80.242	172	204	0.05811	562	604	0.07438	103	80
Leavenworth	Residential Sales Service (910)	1.2953	6,137	17.144	186	265	0.00987	568	680	0.00391	9,679	7,473
Leavenworth	Commercial Sales Service (915)	1.2953	376	127.58	186	265	0.04696	568	680	0.00575	2,120	1,637
Leavenworth	Public Authority Sales Service (915)	1.2953	20	26.2	186	265	0.06950	568	680	0.01399	183	141
Marion lake	Residential Sales Service (910)	1.2953	4,338	12.786	183	293	0.00804	631	701	0.00415	6,602	5,097
Marion lake	Commercial Sales Service (915)	1.2953	489	41.224	183	293	0.01698	631	701	0.0158	1,884	1,454
Marion lake	Public Authority Sales Service (915)	1.2953	118	231.02	183	293	0.03460	631	701	0.0481	1,096	846
Ness City	Residential Sales Service (910)	1.2953	969	15.522	209	304	0.01105	706	734	0.00144	1,368	1,056
Ness City	Commercial Sales Service (915)	1.2953	157	26.966	209	304	0.02183	706	734	0.00313	440	339
Ness City	Public Authority Sales Service (915)	1.2953	39	59.064	209	304	0.03854	706	734	0.01648	208	161
KC Downtown AP	Residential Sales Service (910)	1.2953	73,346	16.581	133	217	0.00959	536	607	0.00661	121,119	93,507
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,474	86.258	133	217	0.04406	536	607	0.02156	30,319	23,407
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	133	217	0.12163	536	607	0.06737	58	45
Sedan	Residential Sales Service (910)	1.2953	2,406	12.687	145	211	0.01034	469	565	0.00439	3,440	2,656
Sedan	Commercial Sales Service (915)	1.2953	338	57.523	145	211	0.04018	469	565	0.00283	1,280	988
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	145	211	NA	469	565	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	837	18.134	251	322	0.01075	685	750	0.00218	981	757
Syracuse	Commercial Sales Service (915)	1.2953	105	73.735	251	322	0.03565	685	750	0.0121	451	348
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	251	322	0.06437	685	750	0.01166	283	218
Ulysses	Residential Sales Service (910)	1.2953	3,174	19.79	234	280	0.00990	716	703	0.0033	1,696	1,309
Ulysses	Commercial Sales Service (915)	1.2953	376	64.975	234	280	0.02846	716	703	0.00891	581	449
Ulysses	Public Authority Sales Service (915)	1.2953	93	200	234	280	0.09714	716	703	0.03167	489	377
											219,436	169,409

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	167,590	129,383
Commercial Sales Service (915)	44,682	34,495
Public Authority Sales Service (915)	2,683	2,071

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	2,677	2,067
Commercial Sales Service (915)	1,032	797
Public Authority Sales Service (915)	772	596
Total	**219,436**	**169,409**

Kansas Weather Normalization Adjustment Program
December-10

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,877	13.058	558	618	0.01072	948	966	0.00356	1,720	1,328
Anthony	Commercial Sales Service (915)	1.2953	253	25.945	558	618	0.02805	948	966	0.00721	594	459
Anthony	Public Authority Sales Service (915)	1.2953	32	80.597	558	618	0.05973	948	966	0.01473	160	123
Chanute	Residential Sales Service (910)	1.2953	6,665	12.48	490	598	0.00906	1008	947	0.00493	5,851	4,517
Chanute	Commercial Sales Service (915)	1.2953	877	30.576	490	598	0.02223	1008	947	0.00927	2,085	1,610
Chanute	Public Authority Sales Service (915)	1.2953	65	56.723	490	598	0.04786	1008	947	0.0288	287	222
Council Grove Lake	Residential Sales Service (910)	1.2953	2,108	12.789	609	688	0.00772	1076	1067	0.00472	1,549	1,196
Council Grove Lake	Commercial Sales Service (915)	1.2953	262	134.495	609	688	0.02011	1076	1067	0.01758	485	375
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	609	688	0.04275	1076	1067	0.02167	202	156
Independence	Residential Sales Service (910)	1.2953	10,005	11.675	494	568	0.00856	967	918	0.00716	3,662	2,827
Independence	Commercial Sales Service (915)	1.2953	1,203	38.242	494	568	0.02598	967	918	0.02366	1,189	918
Independence	Public Authority Sales Service (915)	1.2953	0	NA	494	568	NA	967	918	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	5,806	15.468	562	604	0.00473	1035	971	0.00742	-2,077	(1,604)
Lawrence	Commercial Sales Service (915)	1.2953	353	49.593	562	604	0.01910	1035	971	0.04689	-1,005	(776)
Lawrence	Public Authority Sales Service (915)	1.2953	16	80.242	562	604	0.05811	1035	971	0.07438	-48	(37)
Leavenworth	Residential Sales Service (910)	1.2953	6,145	17.144	568	680	0.00987	1076	1054	0.00391	8,114	6,264
Leavenworth	Commercial Sales Service (915)	1.2953	385	127.58	568	680	0.04696	1076	1054	0.00575	2,560	1,976
Leavenworth	Public Authority Sales Service (915)	1.2953	20	26.2	568	680	0.06950	1076	1054	0.01399	194	150
Marion lake	Residential Sales Service (910)	1.2953	4,382	12.786	631	701	0.00804	1052	1054	0.00415	3,242	2,503
Marion lake	Commercial Sales Service (915)	1.2953	496	41.224	631	701	0.01698	1052	1054	0.0158	784	605
Marion lake	Public Authority Sales Service (915)	1.2953	118	231.02	631	701	0.03460	1052	1054	0.0481	385	297
Ness City	Residential Sales Service (910)	1.2953	974	15.522	706	734	0.01105	1022	1041	0.00144	425	328
Ness City	Commercial Sales Service (915)	1.2953	158	26.966	706	734	0.02183	1022	1041	0.00313	137	106
Ness City	Public Authority Sales Service (915)	1.2953	39	59.064	706	734	0.03854	1022	1041	0.01648	70	54
KC Downtown AP	Residential Sales Service (910)	1.2953	73,600	16.581	536	607	0.00959	1034	975	0.00661	27,733	21,410
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,632	86.258	536	607	0.04406	1034	975	0.02156	11,137	8,598
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	536	607	0.12163	1034	975	0.06737	18	14
Sedan	Residential Sales Service (910)	1.2953	2,423	12.687	469	565	0.01034	951	911	0.00439	2,564	1,980
Sedan	Commercial Sales Service (915)	1.2953	334	57.523	469	565	0.04018	951	911	0.00283	1,620	1,251
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	469	565	NA	951	911	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	826	18.134	685	750	0.01075	952	1060	0.00218	1,000	772
Syracuse	Commercial Sales Service (915)	1.2953	107	73.735	685	750	0.03565	952	1060	0.0121	502	388
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	685	750	0.06437	952	1060	0.01166	289	223
Ulysses	Residential Sales Service (910)	1.2953	3,175	19.79	716	703	0.00990	967	1001	0.0033	-68	(52)
Ulysses	Commercial Sales Service (915)	1.2953	386	64.975	716	703	0.02846	967	1001	0.00891	-34	(26)
Ulysses	Public Authority Sales Service (915)	1.2953	93	200	716	703	0.09714	967	1001	0.03167	-22	(17)
											75,304	58,136

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	52,783	40,749
Commercial Sales Service (915)	19,586	15,121
Public Authority Sales Service (915)	1,268	979

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	932	719
Commercial Sales Service (915)	469	362
Public Authority Sales Service (915)	267	206
Total	75,304	58,136

Kansas Weather Normalization Adjustment Program
January-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,889	13.058	948	966	0.01072	1086	1057	0.00356	220	169
Anthony	Commercial Sales Service (915)	1.2953	256	25.945	948	966	0.02805	1086	1057	0.00721	98	76
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	948	966	0.05973	1086	1057	0.01473	25	19
Chanute	Residential Sales Service (910)	1.2953	6,686	12.48	1008	947	0.00906	1163	1062	0.00493	-9,099	(7,024)
Chanute	Commercial Sales Service (915)	1.2953	870	30.576	1008	947	0.02223	1163	1062	0.00927	-2,583	(1,994)
Chanute	Public Authority Sales Service (915)	1.2953	66	56.723	1008	947	0.04786	1163	1062	0.0288	-498	(385)
Council Grove Lake	Residential Sales Service (910)	1.2953	2,119	12.789	1076	1067	0.00772	1265	1204	0.00472	-981	(757)
Council Grove Lake	Commercial Sales Service (915)	1.2953	264	134.495	1076	1067	0.02011	1265	1204	0.01758	-429	(331)
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	1076	1067	0.04275	1265	1204	0.02167	-108	(84)
Independence	Residential Sales Service (910)	1.2953	10,058	11.675	967	918	0.00856	1098	1040	0.00716	-10,875	(8,396)
Independence	Commercial Sales Service (915)	1.2953	1,215	38.242	967	918	0.02598	1098	1040	0.02366	-4,163	(3,214)
Independence	Public Authority Sales Service (915)	1.2953	0	NA	967	918	NA	1098	1040	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	5,806	15.468	1035	971	0.00473	1238	1089	0.00742	-10,591	(8,177)
Lawrence	Commercial Sales Service (915)	1.2953	352	49.593	1035	971	0.01910	1238	1089	0.04689	-3,743	(2,890)
Lawrence	Public Authority Sales Service (915)	1.2953	16	80.242	1035	971	0.05811	1238	1089	0.07438	-307	(237)
Leavenworth	Residential Sales Service (910)	1.2953	6,178	17.144	1076	1054	0.00987	1259	1191	0.00391	-3,865	(2,984)
Leavenworth	Commercial Sales Service (915)	1.2953	393	127.58	1076	1054	0.04696	1259	1191	0.00575	-725	(560)
Leavenworth	Public Authority Sales Service (915)	1.2953	20	26.2	1076	1054	0.06950	1259	1191	0.01399	-64	(50)
Marion lake	Residential Sales Service (910)	1.2953	4,393	12.786	1052	1054	0.00804	1218	1179	0.00415	-829	(640)
Marion lake	Commercial Sales Service (915)	1.2953	500	41.224	1052	1054	0.01698	1218	1179	0.0158	-377	(291)
Marion lake	Public Authority Sales Service (915)	1.2953	119	231.02	1052	1054	0.03460	1218	1179	0.0481	-278	(215)
Ness City	Residential Sales Service (910)	1.2953	973	15.522	1022	1041	0.01105	1153	1143	0.00144	246	190
Ness City	Commercial Sales Service (915)	1.2953	160	26.966	1022	1041	0.02183	1153	1143	0.00313	79	61
Ness City	Public Authority Sales Service (915)	1.2953	39	59.064	1022	1041	0.03854	1153	1143	0.01648	29	22
KC Downtown AP	Residential Sales Service (910)	1.2953	73,680	16.581	1034	975	0.00959	1221	1108	0.00661	-125,285	(96,723)
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,657	86.258	1034	975	0.04406	1221	1108	0.02156	-30,377	(23,452)
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	1034	975	0.12163	1221	1108	0.06737	-57	(44)
Sedan	Residential Sales Service (910)	1.2953	2,457	12.687	951	911	0.01034	1075	1030	0.00439	-1,945	(1,502)
Sedan	Commercial Sales Service (915)	1.2953	338	57.523	951	911	0.04018	1075	1030	0.00283	-759	(586)
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	951	911	NA	1075	1030	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	833	18.134	952	1060	0.01075	1152	1136	0.00218	1,215	938
Syracuse	Commercial Sales Service (915)	1.2953	108	73.735	952	1060	0.03565	1152	1136	0.0121	512	395
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	952	1060	0.06437	1152	1136	0.01166	359	277
Ulysses	Residential Sales Service (910)	1.2953	3,198	19.79	967	1001	0.00990	1141	1074	0.0033	478	369
Ulysses	Commercial Sales Service (915)	1.2953	394	64.975	967	1001	0.02846	1141	1074	0.00891	189	146
Ulysses	Public Authority Sales Service (915)	1.2953	94	200	967	1001	0.09714	1141	1074	0.03167	144	111
											(204,345)	(157,759)

UCG - Kansas - 081 Div Summary		
Residential Sales Service (910)	(163,004)	(125,843)
Commercial Sales Service (915)	(42,979)	(33,181)
Public Authority Sales Service (915)	(1,260)	(973)

UCG - Kansas - 086 Div Summary		
Residential Sales Service (910)	1,694	1,307
Commercial Sales Service (915)	701	541
Public Authority Sales Service (915)	503	388
Total	(204,345)	(157,759)

Kansas Weather Normalization Adjustment Program
February-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,888	13.058	1086	1057	0.01072	910	786	0.00356	-1,840	(1,420)
Anthony	Commercial Sales Service (915)	1.2953	254	25.945	1086	1057	0.02805	910	786	0.00721	-562	(434)
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	1086	1057	0.05973	910	786	0.01473	-138	(107)
Chanute	Residential Sales Service (910)	1.2953	6,719	12.48	1163	1062	0.00906	977	796	0.00493	-15,730	(12,144)
Chanute	Commercial Sales Service (915)	1.2953	866	30.576	1163	1062	0.02223	977	796	0.00927	-4,401	(3,397)
Chanute	Public Authority Sales Service (915)	1.2953	65	56.723	1163	1062	0.04786	977	796	0.0288	-846	(653)
Council Grove Lake	Residential Sales Service (910)	1.2953	2,112	12.789	1265	1204	0.00772	1038	921	0.00472	-2,799	(2,161)
Council Grove Lake	Commercial Sales Service (915)	1.2953	265	134.495	1265	1204	0.02011	1038	921	0.01758	-1,127	(870)
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	1265	1204	0.04275	1038	921	0.02167	-326	(252)
Independence	Residential Sales Service (910)	1.2953	10,078	11.675	1098	1040	0.00856	908	781	0.00716	-18,351	(14,168)
Independence	Commercial Sales Service (915)	1.2953	1,214	38.242	1098	1040	0.02598	908	781	0.02366	-7,095	(5,477)
Independence	Public Authority Sales Service (915)	1.2953	0	NA	1098	1040	NA	908	781	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	5,827	15.468	1238	1089	0.00473	993	819	0.00742	-15,064	(11,630)
Lawrence	Commercial Sales Service (915)	1.2953	354	49.593	1238	1089	0.01910	993	819	0.04689	-5,046	(3,896)
Lawrence	Public Authority Sales Service (915)	1.2953	16	80.242	1238	1089	0.05811	993	819	0.07438	-448	(346)
Leavenworth	Residential Sales Service (910)	1.2953	6,173	17.144	1259	1191	0.00987	944	907	0.00391	-6,523	(5,036)
Leavenworth	Commercial Sales Service (915)	1.2953	395	127.58	1259	1191	0.04696	944	907	0.00575	-1,743	(1,345)
Leavenworth	Public Authority Sales Service (915)	1.2953	20	26.2	1259	1191	0.06950	944	907	0.01399	-136	(105)
Marion lake	Residential Sales Service (910)	1.2953	4,387	12.786	1218	1179	0.00804	1052	912	0.00415	-5,083	(3,924)
Marion lake	Commercial Sales Service (915)	1.2953	499	41.224	1218	1179	0.01698	1052	912	0.0158	-1,858	(1,434)
Marion lake	Public Authority Sales Service (915)	1.2953	119	231.02	1218	1179	0.03460	1052	912	0.0481	-1,246	(962)
Ness City	Residential Sales Service (910)	1.2953	978	15.522	1153	1143	0.01105	1028	879	0.00144	-412	(318)
Ness City	Commercial Sales Service (915)	1.2953	157	26.966	1153	1143	0.02183	1028	879	0.00313	-139	(107)
Ness City	Public Authority Sales Service (915)	1.2953	39	59.064	1153	1143	0.03854	1028	879	0.01648	-144	(111)
KC Downtown AP	Residential Sales Service (910)	1.2953	73,797	16.581	1221	1108	0.00959	915	835	0.00661	-154,135	(118,995)
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,633	86.258	1221	1108	0.04406	915	835	0.02156	-40,229	(31,058)
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	1221	1108	0.12163	915	835	0.06737	-74	(57)
Sedan	Residential Sales Service (910)	1.2953	2,458	12.687	1075	1030	0.01034	876	769	0.00439	-2,977	(2,298)
Sedan	Commercial Sales Service (915)	1.2953	332	57.523	1075	1030	0.04018	876	769	0.00283	-908	(701)
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	1075	1030	NA	876	769	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	837	18.134	1152	1136	0.01075	959	856	0.00218	-430	(332)
Syracuse	Commercial Sales Service (915)	1.2953	107	73.735	1152	1136	0.03565	959	856	0.0121	-252	(194)
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	1152	1136	0.06437	959	856	0.01166	-118	(91)
Ulysses	Residential Sales Service (910)	1.2953	3,181	19.79	1141	1074	0.00990	981	814	0.0033	-5,004	(3,863)
Ulysses	Commercial Sales Service (915)	1.2953	384	64.975	1141	1074	0.02846	981	814	0.00891	-1,689	(1,304)
Ulysses	Public Authority Sales Service (915)	1.2953	94	200	1141	1074	0.09714	981	814	0.03167	-1,436	(1,109)
											(298,308)	(230,300)

UCG - Kansas - 081 Div Summary		
Residential Sales Service (910)	(222,914)	(172,095)
Commercial Sales Service (915)	(63,107)	(48,720)
Public Authority Sales Service (915)	(3,358)	(2,592)

UCG - Kansas - 086 Div Summary		
Residential Sales Service (910)	(5,434)	(4,195)
Commercial Sales Service (915)	(1,940)	(1,498)
Public Authority Sales Service (915)	(1,555)	(1,200)
Total	(298,308)	(230,300)

Kansas Weather Normalization Adjustment Program
March-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month			Current Month			(Revenue/Excess)	Volume Adjustment
					Actual ADD	Normal ADD	HSF	Actual ADD	Normal ADD	HSF	Deficiency $	
Anthony	Residential Sales Service (910)	1.2953	1,887	13.058	910	786	0.01072	547	602	0.00356	-2,770	(2,139)
Anthony	Commercial Sales Service (915)	1.2953	259	25.945	910	786	0.02805	547	602	0.00721	-1,034	(798)
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	910	786	0.05973	547	602	0.01473	-256	(198)
Chanute	Residential Sales Service (910)	1.2953	6,700	12.48	977	796	0.00906	578	571	0.00493	-14,531	(11,218)
Chanute	Commercial Sales Service (915)	1.2953	876	30.576	977	796	0.02223	578	571	0.00927	-4,639	(3,582)
Chanute	Public Authority Sales Service (915)	1.2953	66	56.723	977	796	0.04786	578	571	0.0288	-758	(585)
Council Grove Lake	Residential Sales Service (910)	1.2953	2,110	12.789	1038	921	0.00772	689	681	0.00472	-2,572	(1,986)
Council Grove Lake	Commercial Sales Service (915)	1.2953	267	134.495	1038	921	0.02011	689	681	0.01758	-862	(666)
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	1038	921	0.04275	689	681	0.02167	-328	(254)
Independence	Residential Sales Service (910)	1.2953	10,109	11.675	908	781	0.00856	554	568	0.00716	-12,922	(9,976)
Independence	Commercial Sales Service (915)	1.2953	1,208	38.242	908	781	0.02598	554	568	0.02366	-4,644	(3,586)
Independence	Public Authority Sales Service (915)	1.2953	0	NA	908	781	NA	554	568	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	5,844	15.468	993	819	0.00473	657	581	0.00742	-10,499	(8,105)
Lawrence	Commercial Sales Service (915)	1.2953	348	49.593	993	819	0.01910	657	581	0.04689	-3,104	(2,397)
Lawrence	Public Authority Sales Service (915)	1.2953	16	80.242	993	819	0.05811	657	581	0.07438	-327	(252)
Leavenworth	Residential Sales Service (910)	1.2953	6,174	17.144	944	907	0.00987	688	693	0.00391	-2,764	(2,134)
Leavenworth	Commercial Sales Service (915)	1.2953	395	127.58	944	907	0.04696	688	693	0.00575	-874	(675)
Leavenworth	Public Authority Sales Service (915)	1.2953	22	26.2	944	907	0.06950	688	693	0.01399	-71	(55)
Marion lake	Residential Sales Service (910)	1.2953	4,397	12.786	1052	912	0.00804	689	682	0.00415	-6,576	(5,077)
Marion lake	Commercial Sales Service (915)	1.2953	504	41.224	1052	912	0.01698	689	682	0.0158	-1,624	(1,254)
Marion lake	Public Authority Sales Service (915)	1.2953	119	231.02	1052	912	0.03460	689	682	0.0481	-799	(617)
Ness City	Residential Sales Service (910)	1.2953	974	15.522	1028	879	0.01105	735	707	0.00144	-2,128	(1,643)
Ness City	Commercial Sales Service (915)	1.2953	157	26.966	1028	879	0.02183	735	707	0.00313	-679	(524)
Ness City	Public Authority Sales Service (915)	1.2953	39	59.064	1028	879	0.03854	735	707	0.01648	-313	(242)
KC Downtown AP	Residential Sales Service (910)	1.2953	73,960	16.581	915	835	0.00959	614	592	0.00661	-87,429	(67,497)
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,671	86.258	915	835	0.04406	614	592	0.02156	-24,196	(18,680)
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	915	835	0.12163	614	592	0.06737	-44	(34)
Sedan	Residential Sales Service (910)	1.2953	2,465	12.687	876	769	0.01034	544	561	0.00439	-3,294	(2,543)
Sedan	Commercial Sales Service (915)	1.2953	337	57.523	876	769	0.04018	544	561	0.00283	-1,856	(1,433)
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	876	769	NA	544	561	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	835	18.134	959	856	0.01075	683	691	0.00218	-1,179	(910)
Syracuse	Commercial Sales Service (915)	1.2953	108	73.735	959	856	0.03565	683	691	0.0121	-500	(386)
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	959	856	0.06437	683	691	0.01166	-347	(268)
Ulysses	Residential Sales Service (910)	1.2953	3,194	19.79	981	814	0.00990	686	665	0.0033	-7,127	(5,502)
Ulysses	Commercial Sales Service (915)	1.2953	392	64.975	981	814	0.02846	686	665	0.00891	-2,508	(1,936)
Ulysses	Public Authority Sales Service (915)	1.2953	93	200	981	814	0.09714	686	665	0.03167	-2,034	(1,571)
											(205,592)	(158,721)

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	(145,487)	(112,319)
Commercial Sales Service (915)	(43,514)	(33,594)
Public Authority Sales Service (915)	(2,896)	(2,236)

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	(8,305)	(6,412)
Commercial Sales Service (915)	(3,008)	(2,323)
Public Authority Sales Service (915)	(2,381)	(1,839)
Total	(205,592)	(158,721)

Kansas Weather Normalization Adjustment Program
April-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,873	13.058	547	602	0.01072	204	298	0.00356	2,242	1,731
Anthony	Commercial Sales Service (915)	1.2953	256	25.945	547	602	0.02805	204	298	0.00721	736	568
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	547	602	0.05973	204	298	0.01473	181	140
Chanute	Residential Sales Service (910)	1.2953	6,710	12.48	578	571	0.00906	244	274	0.00493	734	567
Chanute	Commercial Sales Service (915)	1.2953	867	30.576	578	571	0.02223	244	274	0.00927	138	106
Chanute	Public Authority Sales Service (915)	1.2953	66	56.723	578	571	0.04786	244	274	0.0288	45	35
Council Grove Lake	Residential Sales Service (910)	1.2953	2,123	12.789	689	681	0.00772	306	346	0.00472	349	270
Council Grove Lake	Commercial Sales Service (915)	1.2953	268	134.495	689	681	0.02011	306	346	0.01758	188	145
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	689	681	0.04275	306	346	0.02167	33	26
Independence	Residential Sales Service (910)	1.2953	10,038	11.675	554	568	0.00856	223	268	0.00716	5,748	4,437
Independence	Commercial Sales Service (915)	1.2953	1,216	38.242	554	568	0.02598	223	268	0.02366	2,250	1,737
Independence	Public Authority Sales Service (915)	1.2953	0	NA	554	568	NA	223	268	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	5,815	15.468	657	581	0.00473	261	273	0.00742	-2,037	(1,573)
Lawrence	Commercial Sales Service (915)	1.2953	345	49.593	657	581	0.01910	261	273	0.04689	-397	(307)
Lawrence	Public Authority Sales Service (915)	1.2953	16	80.242	657	581	0.05811	261	273	0.07438	-73	(56)
Leavenworth	Residential Sales Service (910)	1.2953	6,197	17.144	688	693	0.00987	311	357	0.00391	1,840	1,420
Leavenworth	Commercial Sales Service (915)	1.2953	395	127.58	688	693	0.04696	311	357	0.00575	255	197
Leavenworth	Public Authority Sales Service (915)	1.2953	18	26.2	688	693	0.06950	311	357	0.01399	23	18
Marion lake	Residential Sales Service (910)	1.2953	4,399	12.786	689	682	0.00804	299	359	0.00415	1,098	848
Marion lake	Commercial Sales Service (915)	1.2953	491	41.224	689	682	0.01698	299	359	0.0158	527	407
Marion lake	Public Authority Sales Service (915)	1.2953	121	231.02	689	682	0.03460	299	359	0.0481	414	320
Ness City	Residential Sales Service (910)	1.2953	976	15.522	735	707	0.01105	350	386	0.00144	-326	(251)
Ness City	Commercial Sales Service (915)	1.2953	156	26.966	735	707	0.02183	350	386	0.00313	-101	(78)
Ness City	Public Authority Sales Service (915)	1.2953	40	59.064	735	707	0.03854	350	386	0.01648	-25	(19)
KC Downtown AP	Residential Sales Service (910)	1.2953	73,945	16.581	614	592	0.00959	246	280	0.00661	1,318	1,017
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,646	86.258	614	592	0.04406	246	280	0.02156	-1,422	(1,098)
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	614	592	0.12163	246	280	0.06737	-1	(1)
Sedan	Residential Sales Service (910)	1.2953	2,445	12.687	544	561	0.01034	209	266	0.00439	1,349	1,042
Sedan	Commercial Sales Service (915)	1.2953	334	57.523	544	561	0.04018	209	266	0.00283	365	282
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	544	561	NA	209	266	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	827	18.134	683	691	0.01075	293	399	0.00218	340	262
Syracuse	Commercial Sales Service (915)	1.2953	107	73.735	683	691	0.03565	293	399	0.0121	217	168
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	683	691	0.06437	293	399	0.01166	93	72
Ulysses	Residential Sales Service (910)	1.2953	3,183	19.79	686	665	0.00990	319	379	0.0033	-41	(32)
Ulysses	Commercial Sales Service (915)	1.2953	387	64.975	686	665	0.02846	319	379	0.00891	-32	(24)
Ulysses	Public Authority Sales Service (915)	1.2953	94	200	686	665	0.09714	319	379	0.03167	-17	(13)
											16,014	12,363

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	12,316	9,508
Commercial Sales Service (915)	2,540	1,961
Public Authority Sales Service (915)	598	461

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	299	231
Commercial Sales Service (915)	186	143
Public Authority Sales Service (915)	76	59
Total	16,014	12,363

Kansas Weather Normalization Adjustment Program
May-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,868	13.058	204	298	0.01072	109	81	0.00356	2,197	1,696
Anthony	Commercial Sales Service (915)	1.2953	255	25.945	204	298	0.02805	109	81	0.00721	804	621
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	204	298	0.05973	109	81	0.01473	202	156
Chanute	Residential Sales Service (910)	1.2953	6,598	12.48	244	274	0.00906	157	93	0.00493	-374	(288)
Chanute	Commercial Sales Service (915)	1.2953	858	30.576	244	274	0.02223	157	93	0.00927	82	63
Chanute	Public Authority Sales Service (915)	1.2953	66	56.723	244	274	0.04786	157	93	0.0288	-35	(27)
Council Grove Lake	Residential Sales Service (910)	1.2953	2,110	12.789	306	346	0.00772	157	125	0.00472	431	333
Council Grove Lake	Commercial Sales Service (915)	1.2953	264	134.495	306	346	0.02011	157	125	0.01758	83	64
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	306	346	0.04275	157	125	0.02167	65	50
Independence	Residential Sales Service (910)	1.2953	9,935	11.675	223	268	0.00856	146	79	0.00716	-1,216	(939)
Independence	Commercial Sales Service (915)	1.2953	1,211	38.242	223	268	0.02598	146	79	0.02366	-653	(504)
Independence	Public Authority Sales Service (915)	1.2953	0	NA	223	268	NA	146	79	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	5,833	15.468	261	273	0.00473	136	91	0.00742	-2,094	(1,617)
Lawrence	Commercial Sales Service (915)	1.2953	340	49.593	261	273	0.01910	136	91	0.04689	-828	(639)
Lawrence	Public Authority Sales Service (915)	1.2953	16	80.242	261	273	0.05811	136	91	0.07438	-55	(42)
Leavenworth	Residential Sales Service (910)	1.2953	6,188	17.144	311	357	0.00987	164	113	0.00391	2,041	1,576
Leavenworth	Commercial Sales Service (915)	1.2953	390	127.58	311	357	0.04696	164	113	0.00575	943	728
Leavenworth	Public Authority Sales Service (915)	1.2953	18	26.2	311	357	0.06950	164	113	0.01399	58	45
Marion lake	Residential Sales Service (910)	1.2953	4,339	12.786	299	359	0.00804	144	125	0.00415	2,268	1,751
Marion lake	Commercial Sales Service (915)	1.2953	497	41.224	299	359	0.01698	144	125	0.0158	463	357
Marion lake	Public Authority Sales Service (915)	1.2953	117	231.02	299	359	0.03460	144	125	0.0481	176	136
Ness City	Residential Sales Service (910)	1.2953	969	15.522	350	386	0.01105	183	140	0.00144	422	325
Ness City	Commercial Sales Service (915)	1.2953	156	26.966	350	386	0.02183	183	140	0.00313	132	102
Ness City	Public Authority Sales Service (915)	1.2953	40	59.064	350	386	0.03854	183	140	0.01648	35	27
KC Downtown AP	Residential Sales Service (910)	1.2953	73,864	16.581	246	280	0.00959	158	76	0.00661	-20,662	(15,952)
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,585	86.258	246	280	0.04406	158	76	0.02156	-1,603	(1,237)
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	246	280	0.12163	158	76	0.06737	-5	(4)
Sedan	Residential Sales Service (910)	1.2953	2,431	12.687	209	266	0.01034	131	82	0.00439	1,179	910
Sedan	Commercial Sales Service (915)	1.2953	335	57.523	209	266	0.04018	131	82	0.00283	934	721
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	209	266	NA	131	82	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	821	18.134	293	399	0.01075	190	161	0.00218	1,145	884
Syracuse	Commercial Sales Service (915)	1.2953	108	73.735	293	399	0.03565	190	161	0.0121	480	370
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	293	399	0.06437	190	161	0.01166	344	266
Ulysses	Residential Sales Service (910)	1.2953	3,187	19.79	319	379	0.00990	175	148	0.0033	2,084	1,609
Ulysses	Commercial Sales Service (915)	1.2953	385	64.975	319	379	0.02846	175	148	0.00891	732	565
Ulysses	Public Authority Sales Service (915)	1.2953	96	200	319	379	0.09714	175	148	0.03167	618	477
											(9,610)	(7,419)

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	(15,809)	(12,205)
Commercial Sales Service (915)	356	275
Public Authority Sales Service (915)	441	340

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	3,229	2,493
Commercial Sales Service (915)	1,211	935
Public Authority Sales Service (915)	963	743
Total	(9,610)	(7,419)

Kansas Weather Normalization Adjustment Program
June-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,857	13.058	109	81	0.01072	0	6	0.00356	-671	(518)
Anthony	Commercial Sales Service (915)	1.2953	256	25.945	109	81	0.02805	0	6	0.00721	-246	(190)
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	109	81	0.05973	0	6	0.01473	-62	(48)
Chanute	Residential Sales Service (910)	1.2953	6,546	12.48	157	93	0.00906	0	6	0.00493	-4,666	(3,602)
Chanute	Commercial Sales Service (915)	1.2953	856	30.576	157	93	0.02223	0	6	0.00927	-1,516	(1,170)
Chanute	Public Authority Sales Service (915)	1.2953	66	56.723	157	93	0.04786	0	6	0.0288	-247	(191)
Council Grove Lake	Residential Sales Service (910)	1.2953	2,095	12.789	157	125	0.00772	0	13	0.00472	-504	(389)
Council Grove Lake	Commercial Sales Service (915)	1.2953	266	134.495	157	125	0.02011	0	13	0.01758	-143	(110)
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	157	125	0.04275	0	13	0.02167	-69	(53)
Independence	Residential Sales Service (910)	1.2953	9,891	11.675	146	79	0.00856	0	5	0.00716	-6,889	(5,319)
Independence	Commercial Sales Service (915)	1.2953	1,204	38.242	146	79	0.02598	0	5	0.02366	-2,530	(1,953)
Independence	Public Authority Sales Service (915)	1.2953	0	NA	146	79	NA	0	5	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	2,918	15.468	136	91	0.00473	0	5	0.00742	-664	(513)
Lawrence	Commercial Sales Service (915)	1.2953	125	49.593	136	91	0.01910	0	5	0.04689	-101	(78)
Lawrence	Public Authority Sales Service (915)	1.2953	9	80.242	136	91	0.05811	0	5	0.07438	-26	(20)
Leavenworth	Residential Sales Service (910)	1.2953	5,670	17.144	164	113	0.00987	0	7	0.00391	-3,496	(2,699)
Leavenworth	Commercial Sales Service (915)	1.2953	368	127.58	164	113	0.04696	0	7	0.00575	-1,122	(867)
Leavenworth	Public Authority Sales Service (915)	1.2953	18	26.2	164	113	0.06950	0	7	0.01399	-80	(62)
Marion lake	Residential Sales Service (910)	1.2953	4,323	12.786	144	125	0.00804	0	14	0.00415	-530	(409)
Marion lake	Commercial Sales Service (915)	1.2953	488	41.224	144	125	0.01698	0	14	0.0158	-64	(49)
Marion lake	Public Authority Sales Service (915)	1.2953	119	231.02	144	125	0.03460	0	14	0.0481	2	2
Ness City	Residential Sales Service (910)	1.2953	968	15.522	183	140	0.01105	1	19	0.00144	-563	(435)
Ness City	Commercial Sales Service (915)	1.2953	155	26.966	183	140	0.02183	1	19	0.00313	-177	(137)
Ness City	Public Authority Sales Service (915)	1.2953	40	59.064	183	140	0.03854	1	19	0.01648	-70	(54)
KC Downtown AP	Residential Sales Service (910)	1.2953	77,322	16.581	158	100	0.00959	0	6	0.00661	-51,736	(39,941)
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,779	86.258	158	100	0.04406	0	6	0.02156	-15,018	(11,594)
KC Downtown AP	Public Authority Sales Service (915)	1.2953	10	44.997	158	100	0.12163	0	6	0.06737	-86	(67)
Sedan	Residential Sales Service (910)	1.2953	2,413	12.687	131	82	0.01034	0	6	0.00439	-1,501	(1,159)
Sedan	Commercial Sales Service (915)	1.2953	332	57.523	131	82	0.04018	0	6	0.00283	-839	(648)
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	131	82	NA	0	6	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	822	18.134	190	161	0.01075	3	16	0.00218	-302	(233)
Syracuse	Commercial Sales Service (915)	1.2953	102	73.735	190	161	0.03565	3	16	0.0121	-116	(89)
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	190	161	0.06437	3	16	0.01166	-91	(70)
Ulysses	Residential Sales Service (910)	1.2953	3,210	19.79	175	148	0.00990	0	16	0.0033	-892	(689)
Ulysses	Commercial Sales Service (915)	1.2953	385	64.975	175	148	0.02846	0	16	0.00891	-312	(241)
Ulysses	Public Authority Sales Service (915)	1.2953	92	200	175	148	0.09714	0	16	0.03167	-252	(195)
											(95,581)	(73,791)

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	(71,220)	(54,984)
Commercial Sales Service (915)	(21,758)	(16,797)
Public Authority Sales Service (915)	(638)	(493)

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	(1,194)	(922)
Commercial Sales Service (915)	(428)	(330)
Public Authority Sales Service (915)	(343)	(265)
Total	(95,581)	(73,791)

Kansas Weather Normalization Adjustment Program
July-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,833	13.058	0	6	0.01072	0	0	0.00356	153	118
Anthony	Commercial Sales Service (915)	1.2953	253	25.945	0	6	0.02805	0	0	0.00721	55	43
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	0	6	0.05973	0	0	0.01473	14	11
Chanute	Residential Sales Service (910)	1.2953	6,448	12.48	0	6	0.00906	0	0	0.00493	454	351
Chanute	Commercial Sales Service (915)	1.2953	831	30.576	0	6	0.02223	0	0	0.00927	144	111
Chanute	Public Authority Sales Service (915)	1.2953	65	56.723	0	6	0.04786	0	0	0.0288	24	19
Council Grove Lake	Residential Sales Service (910)	1.2953	2,083	12.789	0	13	0.00772	0	0	0.00472	271	209
Council Grove Lake	Commercial Sales Service (915)	1.2953	259	134.495	0	13	0.02011	0	0	0.01758	88	68
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	0	13	0.04275	0	0	0.02167	35	27
Independence	Residential Sales Service (910)	1.2953	9,665	11.675	0	5	0.00856	0	0	0.00716	536	414
Independence	Commercial Sales Service (915)	1.2953	1,154	38.242	0	5	0.02598	0	0	0.02366	194	150
Independence	Public Authority Sales Service (915)	1.2953	0	NA	0	5	NA	0	0	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	2,908	15.468	0	5	0.00473	0	0	0.00742	89	69
Lawrence	Commercial Sales Service (915)	1.2953	110	49.593	0	5	0.01910	0	0	0.04689	14	11
Lawrence	Public Authority Sales Service (915)	1.2953	9	80.242	0	5	0.05811	0	0	0.07438	3	3
Leavenworth	Residential Sales Service (910)	1.2953	5,600	17.144	0	7	0.00987	0	0	0.00391	501	387
Leavenworth	Commercial Sales Service (915)	1.2953	359	127.58	0	7	0.04696	0	0	0.00575	153	118
Leavenworth	Public Authority Sales Service (915)	1.2953	17	26.2	0	7	0.06950	0	0	0.01399	11	8
Marion lake	Residential Sales Service (910)	1.2953	4,250	12.786	0	14	0.00804	0	0	0.00415	620	478
Marion lake	Commercial Sales Service (915)	1.2953	472	41.224	0	14	0.01698	0	0	0.0158	145	112
Marion lake	Public Authority Sales Service (915)	1.2953	112	231.02	0	14	0.03460	0	0	0.0481	70	54
Ness City	Residential Sales Service (910)	1.2953	964	15.522	1	19	0.01105	0	0	0.00144	248	192
Ness City	Commercial Sales Service (915)	1.2953	156	26.966	1	19	0.02183	0	0	0.00313	79	61
Ness City	Public Authority Sales Service (915)	1.2953	40	59.064	1	19	0.03854	0	0	0.01648	36	28
KC Downtown AP	Residential Sales Service (910)	1.2953	76,931	16.581	0	6	0.00959	0	0	0.00661	5,734	4,427
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,594	86.258	0	6	0.04406	0	0	0.02156	1,573	1,214
KC Downtown AP	Public Authority Sales Service (915)	1.2953	10	44.997	0	6	0.12163	0	0	0.06737	9	7
Sedan	Residential Sales Service (910)	1.2953	2,372	12.687	0	6	0.01034	0	0	0.00439	191	147
Sedan	Commercial Sales Service (915)	1.2953	321	57.523	0	6	0.04018	0	0	0.00283	100	77
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	0	6	NA	0	0	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	821	18.134	3	16	0.01075	0	0	0.00218	149	115
Syracuse	Commercial Sales Service (915)	1.2953	102	73.735	3	16	0.03565	0	0	0.0121	61	47
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	3	16	0.06437	0	0	0.01166	44	34
Ulysses	Residential Sales Service (910)	1.2953	3,143	19.79	0	16	0.00990	0	0	0.0033	645	498
Ulysses	Commercial Sales Service (915)	1.2953	376	64.975	0	16	0.02846	0	0	0.00891	222	171
Ulysses	Public Authority Sales Service (915)	1.2953	92	200	0	16	0.09714	0	0	0.03167	185	143
											12,850	9,921

UCG - Kansas - 081 Div Summary		
Residential Sales Service (910)	8,796	6,791
Commercial Sales Service (915)	2,545	1,965
Public Authority Sales Service (915)	203	157

UCG - Kansas - 086 Div Summary		
Residential Sales Service (910)	793	613
Commercial Sales Service (915)	283	218
Public Authority Sales Service (915)	230	177
Total	12,850	9,921

Kansas Weather Normalization Adjustment Program
August-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,834	13.058	0	0	0.01072	0	2	0.00356	17	13
Anthony	Commercial Sales Service (915)	1.2953	252	25.945	0	0	0.02805	0	2	0.00721	5	4
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	0	0	0.05973	0	2	0.01473	1	1
Chanute	Residential Sales Service (910)	1.2953	6,482	12.48	0	0	0.00906	0	3	0.00493	124	96
Chanute	Commercial Sales Service (915)	1.2953	842	30.576	0	0	0.02223	0	3	0.00927	30	23
Chanute	Public Authority Sales Service (915)	1.2953	65	56.723	0	0	0.04786	0	3	0.0288	7	6
Council Grove Lake	Residential Sales Service (910)	1.2953	2,082	12.789	0	0	0.00772	0	8	0.00472	102	79
Council Grove Lake	Commercial Sales Service (915)	1.2953	255	134.495	0	0	0.02011	0	8	0.01758	46	36
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	0	0	0.04275	0	8	0.02167	11	8
Independence	Residential Sales Service (910)	1.2953	9,806	11.675	0	0	0.00856	0	2	0.00716	182	140
Independence	Commercial Sales Service (915)	1.2953	1,219	38.242	0	0	0.02598	0	2	0.02366	75	58
Independence	Public Authority Sales Service (915)	1.2953	0	NA	0	0	NA	0	2	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	2,930	15.468	0	0	0.00473	0	5	0.00742	141	109
Lawrence	Commercial Sales Service (915)	1.2953	122	49.593	0	0	0.01910	0	5	0.04689	37	29
Lawrence	Public Authority Sales Service (915)	1.2953	9	80.242	0	0	0.05811	0	5	0.07438	4	3
Leavenworth	Residential Sales Service (910)	1.2953	5,689	17.144	0	0	0.00987	0	6	0.00391	173	133
Leavenworth	Commercial Sales Service (915)	1.2953	365	127.58	0	0	0.04696	0	6	0.00575	16	13
Leavenworth	Public Authority Sales Service (915)	1.2953	19	26.2	0	0	0.06950	0	6	0.01399	2	2
Marion lake	Residential Sales Service (910)	1.2953	4,303	12.786	0	0	0.00804	0	8	0.00415	185	143
Marion lake	Commercial Sales Service (915)	1.2953	499	41.224	0	0	0.01698	0	8	0.0158	82	63
Marion lake	Public Authority Sales Service (915)	1.2953	121	231.02	0	0	0.03460	0	8	0.0481	60	47
Ness City	Residential Sales Service (910)	1.2953	959	15.522	0	0	0.01105	0	4	0.00144	7	6
Ness City	Commercial Sales Service (915)	1.2953	154	26.966	0	0	0.02183	0	4	0.00313	2	2
Ness City	Public Authority Sales Service (915)	1.2953	40	59.064	0	0	0.03854	0	4	0.01648	3	3
KC Downtown AP	Residential Sales Service (910)	1.2953	77,528	16.581	0	0	0.00959	0	6	0.00661	3,983	3,075
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,873	86.258	0	0	0.04406	0	6	0.02156	817	630
KC Downtown AP	Public Authority Sales Service (915)	1.2953	10	44.997	0	0	0.12163	0	6	0.06737	5	4
Sedan	Residential Sales Service (910)	1.2953	2,377	12.687	0	0	0.01034	0	3	0.00439	41	31
Sedan	Commercial Sales Service (915)	1.2953	319	57.523	0	0	0.04018	0	3	0.00283	4	3
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	0	0	NA	0	3	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	811	18.134	0	0	0.01075	0	5	0.00218	11	9
Syracuse	Commercial Sales Service (915)	1.2953	102	73.735	0	0	0.03565	0	5	0.0121	8	6
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	0	0	0.06437	0	5	0.01166	3	2
Ulysses	Residential Sales Service (910)	1.2953	3,160	19.79	0	0	0.00990	0	3	0.0033	41	31
Ulysses	Commercial Sales Service (915)	1.2953	372	64.975	0	0	0.02846	0	3	0.00891	13	10
Ulysses	Public Authority Sales Service (915)	1.2953	92	200	0	0	0.09714	0	3	0.03167	11	9
											6,250	4,825

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	4,954	3,825
Commercial Sales Service (915)	1,114	860
Public Authority Sales Service (915)	95	73

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	52	40
Commercial Sales Service (915)	21	16
Public Authority Sales Service (915)	14	11
Total	6,250	4,825

Kansas Weather Normalization Adjustment Program
September-11

Weather Station	Tariff Group	Margin Rate	Customer Count	Base Load	Prior Month Actual ADD	Prior Month Normal ADD	Prior Month HSF	Current Month Actual ADD	Current Month Normal ADD	Current Month HSF	(Revenue/Excess) Deficiency $	Volume Adjustment
Anthony	Residential Sales Service (910)	1.2953	1,818	13.058	0	2	0.01072	64	33	0.00356	-209	(162)
Anthony	Commercial Sales Service (915)	1.2953	256	25.945	0	2	0.02805	64	33	0.00721	-56	(43)
Anthony	Public Authority Sales Service (915)	1.2953	30	80.597	0	2	0.05973	64	33	0.01473	-13	(10)
Chanute	Residential Sales Service (910)	1.2953	6,453	12.48	0	3	0.00906	96	46	0.00493	-1,833	(1,415)
Chanute	Commercial Sales Service (915)	1.2953	833	30.576	0	3	0.02223	96	46	0.00927	-428	(331)
Chanute	Public Authority Sales Service (915)	1.2953	66	56.723	0	3	0.04786	96	46	0.0288	-111	(86)
Council Grove Lake	Residential Sales Service (910)	1.2953	2,077	12.789	0	8	0.00772	122	63	0.00472	-583	(450)
Council Grove Lake	Commercial Sales Service (915)	1.2953	258	134.495	0	8	0.02011	122	63	0.01758	-293	(226)
Council Grove Lake	Public Authority Sales Service (915)	1.2953	49	53.63	0	8	0.04275	122	63	0.02167	-59	(46)
Independence	Residential Sales Service (910)	1.2953	9,705	11.675	0	2	0.00856	92	42	0.00716	-4,285	(3,308)
Independence	Commercial Sales Service (915)	1.2953	1,204	38.242	0	2	0.02598	92	42	0.02366	-1,764	(1,362)
Independence	Public Authority Sales Service (915)	1.2953	0	NA	0	2	NA	92	42	NA	NA	
Lawrence	Residential Sales Service (910)	1.2953	5,776	15.468	0	5	0.00473	142	43	0.00742	-5,319	(4,106)
Lawrence	Commercial Sales Service (915)	1.2953	324	49.593	0	5	0.01910	142	43	0.04689	-1,908	(1,473)
Lawrence	Public Authority Sales Service (915)	1.2953	17	80.242	0	5	0.05811	142	43	0.07438	-156	(120)
Leavenworth	Residential Sales Service (910)	1.2953	6,155	17.144	0	6	0.00987	157	58	0.00391	-2,614	(2,018)
Leavenworth	Commercial Sales Service (915)	1.2953	385	127.58	0	6	0.04696	157	58	0.00575	-143	(111)
Leavenworth	Public Authority Sales Service (915)	1.2953	18	26.2	0	6	0.06950	157	58	0.01399	-23	(17)
Marion lake	Residential Sales Service (910)	1.2953	4,250	12.786	0	8	0.00804	131	72	0.00415	-994	(767)
Marion lake	Commercial Sales Service (915)	1.2953	476	41.224	0	8	0.01698	131	72	0.0158	-491	(379)
Marion lake	Public Authority Sales Service (915)	1.2953	116	231.02	0	8	0.03460	131	72	0.0481	-385	(297)
Ness City	Residential Sales Service (910)	1.2953	967	15.522	0	4	0.01105	72	53	0.00144	21	16
Ness City	Commercial Sales Service (915)	1.2953	156	26.966	0	4	0.02183	72	53	0.00313	6	4
Ness City	Public Authority Sales Service (915)	1.2953	39	59.064	0	4	0.03854	72	53	0.01648	-8	(6)
KC Downtown AP	Residential Sales Service (910)	1.2953	73,693	16.581	0	6	0.00959	58	37	0.00661	-7,758	(5,989)
KC Downtown AP	Commercial Sales Service (915)	1.2953	4,519	86.258	0	6	0.04406	58	37	0.02156	-1,103	(851)
KC Downtown AP	Public Authority Sales Service (915)	1.2953	3	44.997	0	6	0.12163	58	37	0.06737	-3	(2)
Sedan	Residential Sales Service (910)	1.2953	2,342	12.687	0	3	0.01034	91	41	0.00439	-572	(441)
Sedan	Commercial Sales Service (915)	1.2953	326	57.523	0	3	0.04018	91	41	0.00283	-9	(7)
Sedan	Public Authority Sales Service (915)	1.2953	0	NA	0	3	NA	91	41	NA	NA	
Syracuse	Residential Sales Service (910)	1.2953	812	18.134	0	5	0.01075	120	66	0.00218	-67	(52)
Syracuse	Commercial Sales Service (915)	1.2953	103	73.735	0	5	0.03565	120	66	0.0121	-63	(49)
Syracuse	Public Authority Sales Service (915)	1.2953	41	64.034	0	5	0.06437	120	66	0.01166	-16	(13)
Ulysses	Residential Sales Service (910)	1.2953	3,129	19.79	0	3	0.00990	109	55	0.0033	-602	(465)
Ulysses	Commercial Sales Service (915)	1.2953	374	64.975	0	3	0.02846	109	55	0.00891	-192	(148)
Ulysses	Public Authority Sales Service (915)	1.2953	92	200	0	3	0.09714	109	55	0.03167	-169	(131)
											(32,202)	(24,860)

UCG - Kansas - 081 Div Summary

Residential Sales Service (910)	(24,146)	(18,641)
Commercial Sales Service (915)	(6,189)	(4,778)
Public Authority Sales Service (915)	(757)	(585)

UCG - Kansas - 086 Div Summary

Residential Sales Service (910)	(669)	(517)
Commercial Sales Service (915)	(255)	(197)
Public Authority Sales Service (915)	(185)	(143)
Total	(32,202)	(24,860)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 8 Sheets

Field Code Changed

SCHEDULE I - GENERAL TERMS AND CONDITIONS FOR SERVICE

SECTION 1 - DEFINITIONS

SECTION 2 - APPLICATION FOR SERVICE

SECTION 3 - CREDIT AND SECURITY DEPOSIT REGULATIONS

Issued: ~~May~~ January ~~12~~26, ~~2008~~2012
(Month) (Day) (Year)

Effective: ~~July 8, 2008~~Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 2 of 8 Sheets

Field Code Changed

SECTION 4 - BILLING AND PAYMENT

SHEET

SECTION 5 - DISCONTINUANCE OF SERVICE

SECTION 6 – CUSTOMER'S SERVICE OBLIGATIONS

Issued: ~~May~~ January ~~12~~26, ~~2008~~2012
(Month) (Day) (Year)

Effective: ~~July 8, 2008~~Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Field Code Changed

Issued: ~~May~~ January ~~12~~26, ~~2008~~2012
(Month) (Day) (Year)

Effective: ~~July 8, 2008~~Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Field Code Changed

Issued: ~~May~~ January ~~12~~26, ~~2008~~2012
(Month) (Day) (Year)

Effective: ~~July 8, 2008~~Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Field Code Changed

Formatted: Font: Arial, 10 pt, Underline

Formatted: Font: Arial, 10 pt, Underline

Formatted: Indent: Left: 0.5", First line: 0"

Formatted: Normal, Left, Line spacing: single

Formatted: Font: Times New Roman, No underline

SCHEDULE II - SCHEDULE OF SERVICE FEES

SHEET

SCHEDULE III - SCHEDULE OF CUSTOMER ADVANCES FOR CONSTRUCTION OF MAINS AND COMPANY SERVICE LINES

SCHEDULE IV - SALES AND TRANSPORTATION RATES

Issued: ~~May~~ January ~~12~~26, ~~2008~~2012
(Month) (Day) (Year)

Effective: ~~July 8, 2008~~ Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Field Code Changed

Issued: ~~May~~ January ~~12~~26, ~~2008~~2012
(Month) (Day) (Year)

Effective: ~~July 8, 2008~~Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 7 of 8 Sheets

Field Code Changed

Issued: ~~May~~ January ~~12~~26, ~~2008~~2012
(Month) (Day) (Year)

Effective: ~~July~~ ~~8,~~ ~~2008~~Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding
shall modify the tariff as shown hereon.

Sheet 8 of 8 Sheets

Field Code Changed

SCHEDULE VI - WEATHER NORMALIZATION ADJUSTMENT (WNA)

SCHEDULE VII - AD VALOREM TAX SURCHARGE

SCHEDULE VIII – GAS SYSTEM RELIABILITY SURCHARGE RATE

SCHEDULE IX – CUSTOMER RATE STABILIZATION

Formatted: Font color: Auto

Issued:	~~May~~ January ~~12~~26,	~~2008~~2012	
	(Month)	(Day)	(Year)
Effective:	~~July~~ ~~8,~~ ~~2008~~Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)		(Title)

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Formatted: Left: 0.75", Right: 0.5"

Formatted: Left

SECTION 13 – INTERCONNECTION AGREEMENT

INTERCONNECT AGREEMENT

Re: Interconnect Agreement
AE-IA# ; [Company Name] Tap & Measuring Station located in town of , State of Project #

On this day of , 20 , ("Interconnector or Company Name"), a corporation and Atmos Energy Corporation, a Texas and Virginia corporation ("Atmos") sometimes referred to herein individually as a "Party" and collectively as the "Parties," Enter into this Interconnect Agreement ("Agreement")AE-IA# .

WHEREAS, desires to interconnect with Atmos; and

WHEREAS, the Parties desire to set forth their understanding regarding the design, construction, installation, operation, maintenance, and ownership of certain interconnecting facilities to connect the Interconnector's , located in County/Parish, , to Atmos' natural gas pipeline system located at .

NOW, THEREFORE, in consideration of the mutual covenants and agreements contained herein, the adequacy and sufficiency of which are acknowledged, the Parties agree as follows:

I. CONSTRUCTION AND INSTALLATION OF THE FACILITIES

A. Interconnector's Responsibilities.

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

1. Interconnector shall design, construct, install, and may replace at its sole expense, any upstream interconnecting pipeline(s), measuring facility as described on Exhibit "A", gas monitoring equipment, and telemetry, including but not limited to meters, regulators, valves, gas analyzers, shut-in valves, separators, filters, odorizers and such other equipment (collectively, "Measurement Facilities") necessary to connect Interconnector's well (s) to Atmos' Tap Facilities (defined below). All components shall be approved by Atmos. Interconnector will be solely responsible for supplying at its sole expense, electric service to its Measurement Facilities and Atmos' Tap Facilities.

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

2. Prior to construction of the Measurement Facilities, Interconnector will provide design drawings, sealed by a professional engineer licensed in the state which the Measurement Facilities will be installed, to Atmos for review, and Interconnector will not begin construction until acceptance of the design drawings is received from Atmos. Drawings as shown in Exhibit "B provided by Atmos Energy are conceptual in nature only and are not to be used for final construction".
3. Upon completion of construction of the Measurement Facilities, Interconnector will promptly provide sealed as-built drawings (piping, instrumentation and control) and code compliance documentation to Atmos.

B. **Atmos' Responsibilities.**

Formatted: Bullets and Numbering

1. Atmos shall design, construct, install, own, operate, and maintain, at Interconnector's expense "Tap Facilities" consisting of a ___ inch hot tap and valve, a riser containing a riser block valve, check valve and insulating flange which will be used to denote the Division of Ownership between Atmos and Interconnector with regards to piping, telemetry/SCADA equipment and other equipment installed by both parties located at ________________________________.

Formatted: Bullets and Numbering

2. Atmos will review in a timely manner all design drawings provided by Interconnector for Atmos' review in accordance with the provisions of this Agreement.

C. **General Items.**

Formatted: Bullets and Numbering

1. All of the design and construction activities of Atmos and/or Interconnector described in this Agreement will be in accordance with "Material and Construction Specifications for Facilities Constructed by non-Atmos Contractors and Third Parties" which are incorporated herein by reference and are available to Interconnector, as they may change from time to time, on ATMOS' Web Site at :

Formatted: Bullets and Numbering

https://www.atmosenergy.com/cs/interconnect/index.html

by using Interconnector's special assigned ID and Password set out in Exhibit "C," which is incorporated herein by reference. In the event such specifications do not set forth details specific enough for Interconnector to carry out any of the design or construction activities described in this Agreement, Interconnector will obtain a written clarification or exception from the applicable division's Atmos Technical Services Department before taking action. All ID's and Passwords are valid for limited periods of time and ATMOS will provide a new ID and Password upon email request as provided in Exhibit "C."

2. Due to the accelerated time schedule for the installation of the Measurement Facilities, Atmos and Interconnector both recognize that certain specified types of equipment may not be available during the initial installation of the Facilities. If a temporary substitution of equipment for the measuring station is desired by Interconnector during the initial construction of the Measurement Facilities, then Interconnector will notify the Atmos Technical Services Department of the nature of the temporary substitution and will obtain Atmos' written permission for an approved substitution. As soon as practicable thereafter the Measurement Facilities' in-service date, Interconnector will advise Atmos when the originally specified equipment is available and will

Formatted: Bullets and Numbering

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

coordinate activities with Atmos so that the temporary equipment may be removed and the originally specified equipment may be installed. All costs associated with the change-out of said equipment will be borne solely by Interconnector. Ownership of the temporary equipment will remain with the Party supplying such equipment.

3. Notwithstanding any provision of this Agreement, or any other agreement between the Parties, to the contrary, no compressor shall be physically located within 100 feet of the Measurement Facilities. Applicable pulsation attenuation devices will be required if the Measurement Facilities are connected, directly or indirectly, to a compressor by less than 1000 feet of pipe. Requirements for pulsation attenuation devices for direct or indirect connections of the Measurement Facilities to a compressor by more than 1000 feet of pipe will be evaluated by the applicable division's Atmos Technical Services Department. Furthermore, in the event that vibration or noise originating from the Measurement Facilities, any upstream Interconnector's equipment, or any third-party source results in measurement inaccuracy, or additional gas quality monitoring, or the range of control or measurement is insufficient for accurate control or measurement, then Interconnector agrees to remedy such issue to Atmos' reasonable satisfaction at the sole cost and expense of the Interconnector. Notwithstanding anything herein to the contrary, no upstream or downstream facilities (including, but not limited to, compression, dehydration, separation, pigging, processing and/or treating) shall be located within 100 feet of the Measurement Facilities without the written consent of Atmos.

II. OWNERSHIP AND OPERATION OF THE MEASUREMENT FACILITIES

A. **Interconnector's Responsibilities.**

1. Upon completion of the construction and installation of the Measurement Facilities and Tap Facilities, Interconnector will own the Measurement Facilities, including any separating and over-pressure protection equipment installed by Interconnector.
2. Interconnector will own and operate all piping and equipment upstream of the Measurement Facilities.
3. Interconnector will be responsible for acquiring all operating, regulatory, and environmental permits in its name that are necessary for the construction, operation, and maintenance of the Measurement Facilities.

Formatted: Bullets and Numbering

B. **Atmos' Responsibilities.**

1. Upon completion of the construction and installation of the Measurement Facilities and Tap Facilities, Atmos shall own the Tap Facilities. Atmos shall also operate and maintain, at Interconnector's expense, the Measurement Facilities.
2. Atmos will test, calibrate, and commission the Measurement Facilities.
3. ATMOS will be solely responsible for all daily operational activities performed in connection with the Tap Facilities and Measurement Facilities, including, but not limited to, operation, testing, calibration, adjusting and maintenance necessary for the utilization of the Tap Facilities, the Measurement Facilities, and telemetry associated therewith.

Formatted: Bullets and Numbering

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION (Name of Issuing Utility)

SCHEDULE I – Rules and Regulations

ENTIRE SERVICE AREA (Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 114 of Sheets

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

III. PAYMENT

A. **Advance Payment.**

1. Upon execution of this Agreement, Interconnector shall pay Atmos ($) (the "Advance Payment") representing the estimated cost for Atmos' installation of the Tap Facilities, Atmos' review of the design drawings and Atmos' expenses, including, but not limited to, inspection expenses, related to the Measurement Facilities' construction, start-up and commissioning.
2. The estimated cost for construction and installation of the Tap Facilities and other Atmos costs shall include, but not be limited to, the cost of material, supplies, labor (Atmos and contractor), vehicles, gas loss, tax gross-up, interest carrying charges (CIAC gross-up), franchise fees, and overhead.

Formatted: Bullets and Numbering

B. **Actual Cost.**

1. After all costs have been determined, Atmos shall submit to Interconnector a final invoice setting forth the actual costs incurred by Atmos (the "Actual Cost"). If the Actual Cost is less than the Advance Payment, Atmos shall refund the difference to Interconnector together with the final invoice. If the Actual cost is greater than the Advance Payment, Interconnector shall pay Atmos the difference within thirty (30) days of Interconnector's receipt of the final invoice.
2. Actual Cost shall include, but not be limited to, the cost of material, supplies, labor (Atmos and contractor), vehicles, gas loss, tax gross-up, interest carrying charges (CIAC gross-up), franchise fees, and overhead.

Formatted: Bullets and Numbering

C. **Monthly Routine Maintenance Payment.**

1. For the performance of Routine Maintenance, as defined in Article VI, Section A below, Atmos shall charge Interconnector an estimated monthly fee of $ 325 . The monthly fee may be adjusted annually, upward or downward.

Formatted: Bullets and Numbering

Formatted: Not Highlight

D. **Terms.**

1. If the amount of any invoice is not paid within 30 days, interest on all unpaid amounts will accrue at the rate of 1½% per month, or the highest rate allowed by law, whichever is less, from the date such amount is due Atmos; provided, however, no interest will accrue on unpaid amounts when failure to make payment is the result of a bona fide dispute between the Parties regarding such amounts (and Interconnector timely pays all amounts not in dispute), unless and until it is ultimately determined that Interconnector owes such disputed amounts, whereupon Interconnector will pay Atmos that amount, plus interest computed back to the original payment due date, immediately upon such determination.

Formatted: Bullets and Numbering

Issued: January 26, 2012
(Month) (Day) (Year)

Effective: Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

2. If Interconnector fails to pay invoices for service within thirty (30) days from the invoice date or otherwise defaults under this Agreement, Atmos may suspend service and deliveries of gas and such suspension will not prevent enforcement by Atmos of any of its legal rights
3. It is further agreed that upon the event that Interconnector fails to pay Atmos any of the monies described in this Agreement within thirty (30) days of the date of Atmos' invoice and the collection of any such amounts is placed in the hands of an attorney for collection, or suit is brought on the same, or same is collected through bankruptcy or probate proceedings, then Interconnector additionally agrees to pay all of Atmos' court costs and attorney's fees, which shall be added to the amounts due to Atmos hereunder.
4. In addition, notwithstanding any other provision in this Agreement, or any other agreement between the Parties to the contrary, in the event that Interconnector fails to pay Atmos any of the monies due to Atmos pursuant to this Agreement within thirty (30) days of the date of Atmos' invoice therefore, in addition to any other rights or remedies available to Atmos, Atmos will have the right to suspend or terminate all performance under this Agreement as hereinafter defined, and suspend or terminate all receipt and/or delivery of gas for or on behalf of Interconnector through the gas facilities constructed under this Agreement until such sums are paid to Atmos.
5. Each Party will have the right at all reasonable times to examine the records of the other Party, or its agent/designee if any, to the extent necessary to verify the accuracy of any statement, charge, computation or demand made under or pursuant to any of the provisions in this Agreement. If any such examination reveals any inaccuracy in a statement, the necessary adjustments to such statement will be made; provided, however, no adjustments for any statement will be made for any inaccuracy claimed unless written notice of such claim for adjustment is furnished to the other Party within six (6) months from the rendition of the statement for which such adjustment is requested.

IV. NOTICES

All notices, requests, demands, statements and payments provided for in this Agreement must be given in writing directed to the Party to whom given, and mailed to or delivered at such Party's address set forth below, and will be deemed properly and sufficiently given when: (i) delivered in person with receipt acknowledged in writing by the receiving Party; (ii) sent by registered or certified mail, return receipt requested, to the address specified below; (iii) received at the electronic mail address, if any, specified below; or (iv) sent by telephonic document transfer to the fax number, if any, specified below:

"Interconnector"

(Notices) (Invoices)

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Attention: Contract Administration
Fax:
E-mail -

Attention: Accounting Department
Fax:
E-mail -

"Atmos"

(Notices)
Atmos Energy

Attn:
Fax:
E-mail –

V. LAND RIGHTS

1. Interconnector will procure any easement, lease or other property right for the location of the Measurement Facilities , along with those Tap Facilities not to be located on an existing Atmos easement, lease, or other property right, as well as an all-weather road providing access for Atmos to the Tap Facilities and the Measurement Facilities. Any easement, lease, or other property right that is acquired by Interconnector for the installation, operation, maintenance, and replacement of Tap Facilities, shall be assigned to Atmos including the surface easement or surface lease and right of ingress or egress to Atmos, its assign, or its successors prior to the Tap Facilities' in-service date. Should the contract be terminated or the Interconnector abandons its facilities or removes them, Atmos shall continue to have the right to have its facilities in place and Interconnector shall wholly assign its easement or surface lease to Atmos.

Formatted: Bullets and Numbering

2. Prior to negotiating or procuring any easement, lease, or other property right (the "Property Rights") associated with any equipment to be installed, operated, or owned by Atmos hereunder, Interconnector must obtain written approval from Atmos of the format and content of the documents (including a plat of the location of the Property Rights) used to secure the Property Rights (the "Instruments"). No Instrument will deviate from Atmos' standard templates used to acquire Property Rights with regard to, but not by way of limitation,

easement width, access rights, term, multiple-line rights, or above-ground rights, liability and indemnification without the prior written approval of Atmos. Copies of Atmos standard templates will be provided to Interconnector upon request. Licenses or permits will not be acceptable substitutes for the Instruments, except with the prior written approval of Atmos.

3. All pipeline easements, if applicable, will be at least fifty-feet (50') wide and the measuring station site will be at least one-hundred feet (100') by one-hundred feet (100') in size, unless the Parties mutually agree in writing to smaller sizes.

VI. OPERATION AND MAINTENANCE

A. Routine Maintenance

1. Atmos shall perform all of its obligations set forth above. Interconnector will be responsible for all costs associated with the maintenance, repair and replacement costs of the Tap Facilities, telemetry and Measurement Facilities associated therewith.

Formatted: Bullets and Numbering

2. All operations will be performed in accordance with Atmos' Inspection, Operation and Maintenance Manual and all of the personnel performing covered tasks related to the tap, measuring station and telemetry associated therewith will be qualified under Atmos' Operator Qualification Program.
3. Any individual maintenance, repair(s) or replacement(s) costing $5,000.00 or less, and any emergency maintenance, repair(s) or replacement(s) may be made by Atmos within its discretion without approval by Interconnector.
4. If Atmos determines that any necessary maintenance, repair or replacement of equipment, other than an emergency maintenance, repair or replacement, will exceed $5,000.00, then Atmos will seek to obtain written approval from Interconnector prior to making such maintenance, repair or replacement.
5. In the event Interconnector does not provide Atmos with its timely approval of any repair or replacement of equipment costing in excess of $5,000.00 deemed necessary by Atmos, in its own reasonable discretion, Atmos may, by notice to Interconnector, suspend the receipt of gas from Interconnector through the Tap Facilities until the Parties mutually agree upon a repair, replacement or other course of action.
6. After Atmos performs any maintenance, repair or replacement of equipment pursuant to the terms of this Article VI, Atmos will forward to Interconnector a statement setting forth the total costs attributable to such maintenance, repair or replacement, and payment will be made by Interconnector to Atmos as provided in Article III.
7. If additional telemetry or telecommunication links must be installed to: (a) establish or maintain safe, prudent or economic operating conditions, or (b) accurately monitor the flow of gas to Atmos at the Tap Facilities, in Atmos sole reasonable opinion, Atmos will install such facilities and Interconnector will reimburse Atmos for the actual cost incurred.
8. If additional equipment is required to ensure consistent delivery of gas meeting Atmos' gas quality specifications as stated in Exhibit "D", Atmos may require Interconnector to purchase and install promptly, at

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Interconnector's sole cost and expense, additional equipment as may be necessary to meet the gas quality specifications.

9. If, in Atmos' sole opinion: (a) the flow turndown or range on the meter installed at the measuring station is insufficient for accurate measurement on a day-to-day or an hour-to-hour basis; (b) the flow turndown or range on the regulator(s) or control valve(s) installed at the measuring station is insufficient for stable and accurate flow or pressure control; or (c) the existing monitoring and shut-in equipment is not adequate and that additional monitoring equipment and/or automatic shutdown equipment are necessary at the measuring station, Atmos may require Interconnector to purchase and install promptly, at Interconnector's sole cost and expense, additional equipment that meets Atmos' standards for measurement, stability, and control at the measuring station.
10. If, in Atmos' sole opinion, pulsation originating from a compressor, or associated facilities, upstream of the measuring station is responsible for either an intermittent or continuous measurement inaccuracy at the measuring station, Interconnector agrees to remedy such pulsation to Atmos' reasonable satisfaction at Interconnector's sole expense
11. Interconnector will, at the request of Atmos, assign such permits and regulatory and/or court approvals to Atmos to the extent they apply to facilities or equipment owned by Atmos during or after termination of this Agreement.
12. If after notification to Interconnector by Atmos regarding failure to comply with any of the terms and conditions of this Agreement, Atmos shall have the right to cease taking gas through the Measuring Facilities. Atmos reserves the right to cease taking gas immediately without prior notification if at any time the gas fails to meet the required gas quality specifications. Atmos shall have the right to cease taking gas immediately if at any time the warranty of ownership of such gas is contested.

VII. MISCELLANEOUS

Formatted: Bullets and Numbering

1. As between the Parties, Atmos will act as, and be deemed to be, an independent contractor with respect to the installation of any equipment by Atmos and any other act or omission related to this Agreement. Atmos will have the sole right to control and directly supervise the method, manner and details of the installation of such facilities and Atmos may, in its sole discretion, employ or use third parties, including, without limitation, contractors, subcontractors or materials men, to install all or any part of such facilities.
2. As between the Parties, Interconnector will act as, and be deemed to be, an independent contractor with respect to the installation of any equipment by it and any other act or omission related to this Agreement. Interconnector will have the sole right to control and directly supervise the method, manner and details of the installation of such facilities and Interconnector may, in its sole discretion, employ or use third parties, including, without limitation, contractors, subcontractors or materials men, to install all or any part of such facilities.
3. A waiver by either Party of any breach of this Agreement, or the failure of either Party to enforce any provision of this Agreement, will not in any way affect, limit or waive that Party's right to thereafter enforce and compel strict compliance with the same or other provisions of this Agreement.

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

4. In the event either Party is rendered unable, wholly or in part, by force majeure to carry out its obligations under this Agreement, except the obligation to pay monies due hereunder, it is agreed that, on such Party's giving notice concisely describing the cause of such force majeure, in writing or by fax, email, electronic transfer or telecopy, to the other Party within a reasonable time after the occurrence of the cause relied on, the obligations of the Party giving such notice, to the extent they are affected by such force majeure, will be suspended during the continuance of any inability so caused, but for no longer period, and such cause will, so far as possible, be remedied with all reasonable dispatch. The inability, or the failure of a Party perform a duty or obligation under this Agreement due to force majeure may not be the basis of claims for damages sustained by either Party or for breach of contract.
    a. The term "force majeure" as employed herein shall mean, but not by way of limitation, acts of God, the elements, strikes, lockouts or other labor or industrial disturbances, acts of the public enemy, arrests, wars, blockades, insurrections, riots, civil disturbances, criminal act, vandalism, terrorism or a terrorist act or acts and epidemics; landslides, lightning, earthquakes, fires, hurricanes, storms, floods and washouts; arrests, orders, directives, restraints and requirements, priority limitation or restraining orders of any government or governmental agencies, whether federal, state, civil or military; accident or obstructions involving a pipeline, machinery or lines of pipe; repairs or outages (shutdowns) of power plant equipment or lines of pipe for inspection, maintenance, change or repair; freezing of lines of pipe; tests, maintenance, or repairs to machinery, equipment, lines of pipe or other facilities; freezing of equipment, lines of pipe or other facilities; inability to obtain, or unavoidable delay in obtaining, material, equipment, rights-of-way or permits; and any other causes, whether of the kind herein enumerated or otherwise, not reasonably within the control of the Party claiming suspension. Further, it is agreed that that the handling of litigation with third parties of any fact or issue and the settlement of strikes or lockouts will be entirely within the discretion and control of the Party involved, and that the above reasonable dispatch will not require any particular action or the settlement of strikes or lockouts by acceding to the demand of the opposing third party when such course is deemed to be inadvisable or inappropriate in the discretion of the Party involved.
5. Atmos shall have the right to curtail, interrupt or discontinue service in whole or in part on all or part of its system from time to time. This may be in order to perform repair, maintenance, replacement or miscellaneous construction on the system as necessary to maintain operational capability or comply with applicable governmental regulations or for other reasons as deemed necessary by Atmos and shall not be liable to INTERCONNECTOR in any manner due to any such curtailment, interruption or discontinuance of service. ATMOS shall exercise due diligence to schedule such activities so as to minimize interruptions or disruption of services and shall provide reasonable advance notice of same.
6. Nothing in this Agreement will create, or be construed as creating; any express or implied rights in any person or entity other than Atmos and Interconnector.
7. The term of this Agreement will be for a primary term of ___ years beginning ____________ and having a termination date of ____________, and then year to year thereafter, until cancelled by either Party giving written notice at least 90 days prior to the end of the primary term or any year thereafter. Within one year after the termination of this Agreement, Interconnector will have the right, upon at least 30 days prior written notice to Atmos, to remove its measuring station, but will continue to indemnify Atmos pursuant to the

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

provisions of this Agreement for Interconnector's activities prior to and during such removal. Notwithstanding any provision of this Agreement to the contrary, all obligations and duties of Atmos under this Agreement will be suspended until and commence after: (a) Atmos receives two (2) originals of the form of this Agreement; (b) Atmos receives the Advance Payment from Seller described in Article III; and (c) Atmos executes the two (2) originals of the form of this Agreement that have been fully executed by INTERCONNECTOR

8. THIS AGREEMENT WILL BE CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, NOTWITHSTANDING ANY CONFLICT OF LAW PRINCIPLES THAT MIGHT REQUIRE THE APPLICATION OF THE LAWS OF ANOTHER JURISDICTION. This Agreement is made, and is performable, in County (Parish), . This Agreement is subject to all applicable state and federal laws, and all orders, directives, rules and regulations of any governmental body, official or agency having jurisdiction.
9. The Parties agree that the rates and terms of this Agreement have been reached through arms length negotiations and that neither Party had an unfair advantage during the negotiations thereof.
10. EXCEPT IN REGARD TO DAMAGES TO THIRD PARTIES FOR WHICH ONE PARTY MAY BE INDEMNIFIED BY THE OTHER PARTY, IN THE EVENT ONE PARTY IS LIABLE TO THE OTHER PARTY DUE TO ANYTHING RELATED TO THIS AGREEMENT, WHETHER ARISING IN CONTRACT, EQUITY OR TORT (INCLUDING WITHOUT LIMITATION ANY CLAIM FOR NEGLIGENCE OR STRICT LIABILITY,), THE AMOUNT OF DAMAGES RECOVERABLE WILL NOT INCLUDE ANY AMOUNT FOR SPECIAL, CONTINUING, EXEMPLARY, PRESUMPTIVE, INCIDENTAL, INDIRECT OR CONSEQUENTIAL DAMAGES (WHICH TERMS SHALL INCLUDE LOST PROFITS, LOST INCOME AND LOST SAVINGS), OR FOR ANY AMOUNT RELATED TO CLAIMS AGAINST THE ONE PARTY BY ANY THIRD PARTY OR PARTIES, EXCEPT THOSE DAMAGES TO A THIRD PARTY OR PARTIES FOR WHICH THE ONE PARTY MAY BE INDEMNIFIED BY THE OTHER PARTY, AS PROVIDED FOR IN THIS AGREEMENT.
11. This Agreement will be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns; provided, however, that Interconnector may not assign any of its rights or obligations under this Agreement without the express, written consent of ATMOS, which consent will not be unreasonably withheld. No assignment will relieve the assigning Party of any of its duties or obligations under this Agreement.
12. Except as required by law, regulation, or order of government authority (including, but not limited to, any filings required by the Securities and Exchange Commission in the normal conduct of either party's business), order of a court or arbitrator(s), or upon written consent of the other party, each party and its respective agents, employees, affiliates, officers, directors, and attorneys, auditors and other representatives shall keep and maintain this agreement and the terms or provisions thereof in strict confidence, and shall not transmit, reveal, disclose or otherwise communicate any of the terms and provisions of this agreement to any person without first obtaining the consent of the other party, which consent shall not be unreasonably withheld. This section shall not apply to any required reporting by Atmos or Interconnector pursuant to orders or regulations of any regulatory authority with proper jurisdiction.
13. This Agreement constitutes the entire agreement between the Parties covering the subject matter hereof, and there are no agreements, modifications, conditions or understandings, written or oral, express or implied, pertaining to the subject matter hereof that are not contained herein.

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

14. Each and every term or obligation in this Agreement is separate and independent from every other term or obligation, and the breach of any term or obligation will in no way or manner discharge or relieve the performance of any other term or obligation. Each and all of the rights and remedies given to either Party by this Agreement, or by law or in equity, are cumulative, and the exercise of any such right or remedy by either Party will not impair such Party's right to exercise any other right or remedy available to such Party, under this Agreement, or by law or in equity.
15. If any provision of this Agreement is held invalid by any court or regulatory authority, then such provision will be deemed severable and the remainder of this Agreement will continue in full force and effect.
16. Notwithstanding any other provision of this Agreement or any other agreement of the Parties, any and all electronic versions of this Agreement and any amendments thereto shall be considered to be drafts and the only effective version of this Agreement or any amendment hereto shall be a written, hard copy executed by both Parties.
17. This Agreement is not an agreement to transport, buy or sell gas. Any transportation, sale or purchase of gas through the Measurement Facilities described in, upgraded, installed or constructed under this Agreement will be performed under the terms and conditions of one or more separate written agreements. No sale, purchase, receipt, delivery or transportation of gas will be performed under the terms of this Agreement. Further, the Parties agree that this Agreement does not waive any gas quality specifications in any agreement.

VIII. INDEMNITY

Notwithstanding any other provision in this Agreement, each Party ("Indemnifying Party") agrees to protect, defend, indemnify and hold the other Party ("Indemnified Party"), its directors, officers, employees, attorneys-in-fact, agents, partners and affiliated companies, free and harmless from and against any and all losses, claims, liens, demands, and causes of action of every kind and character, including, but not limited to, the amounts of judgments, penalties, interest, court costs, investigation expenses and costs and attorney's fees incurred by the Indemnified Party, its directors, officers, employees, attorneys-in-fact, agents, partners and affiliated companies, in defense of same arising in favor of any governmental agencies, third parties, contractors or subcontractors, on account of taxes claims, liens, debts, personal injuries, death or damages to property, and all other claims or demands of every character occurring or in any way incident to, in connection with, or arising out of the Indemnifying Party's or its contractor's or subcontractor's negligence, gross negligence or willful misconduct solely related to activities performed under this agreement, except to the extent that any such liability, loss, claim, damage, cost or expense is caused by the actions, omissions, negligence, gross negligence, willful misconduct, fault or breach of the other Party. This Section will survive the termination of this Agreement.

ACCEPTED AND AGREED TO THIS ___ DAY OF ______, 20__.	ACCEPTED AND AGREED TO THIS ___ DAY OF ______, 20__.
[Interconnector]	ATMOS ENERGY CORPORATION

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE I – Rules and Regulations

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 122 of Sheets

By: By:

Name: Name:

Title: Title:

Issued: January 26, 2012
(Month) (Day) (Year)

Effective: Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE I – Rules and Regulations

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 123 of Sheets

EXHIBIT "A"

(i) a " orifice meter; (ii) a " ultrasonic meter; (iii) a control valve, with control valve panel; (iv) overpressure protection with automatic shut-in valve; (v) a check valve, (vi) an electronic flow measurement device, and appurtenances with a communication interface (collectively, the "EFM"); (vii) an ATMOS approved gas chromatograph ("GC") with appropriate shut-in capabilities; (viii) a hydrogen sulphide ("H2S") monitor(s), with an automatic shut-in valve (with the capability to shut off and prevent the flow of any gas that does not meet the Applicable Gas Quality Specifications into ATMOS' facilities), related tubing, manifolds and hand valves, that will constantly monitor all gas that flows into ATMOS' facilities, as well as electric power for the H2S monitor, instrumentation and tubing; (ix)an odorizer and appropriately sized odorant tank (together the "Odorizer"); (x) a moisture monitor with an automatic shut-in valve; (xi) a drip pot with level switch and appropriate liquids monitoring and shut-in equipment; (capable of preventing the flow of gas into ATMOS' facilities that does not meet the Applicable Gas Quality Specifications); (xii)an equipped telemetry building, and all related instrumentation and tubing not provided by ATMOS under Section 2; (xiii) oxygen monitor with automatic shut-in valve; and (xiv) electric power and telephone service for the operation of the facilities described above

Issued: January 26, 2012
(Month) (Day) (Year)

Effective: Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

EXHIBIT "B"

Drawings

3rd Party Receipt into an Atmos Distribution Line -- drawing number PD 11985 sheets 1 through 5

- Sheet 1 of 5 – Piping and Instrumentation Diagram
- Sheet 2 of 5 – Standard P & ID Legend
- Sheet 3 of 5 – Typical 2" Measuring Station Lot Layout
- Sheet 4 of 5 - Plans, Sections and Details
- Sheet 5 of 5 –2" Regulator and Meter Spools

Formatted: Bullets and Numbering

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE I – Rules and Regulations

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 125 of Sheets

EXHIBIT "C"

To that Certain Interconnect Agreement dated ____________, 2008, BETWEEN Atmos ____________, a division of Atmos Energy Corporation and ________________

__________'s USER ID and PASSWORD to ATMOS' INTERNET WEB SITE

Internet Web Address:

https://www.atmosenergy.com/cs/interconnect/index.html

User IED: ________________ **
Password: ________________ **

**** The above ID and Password are valid until ________________.**

Issued:	January	26,	2012
	(Month)	(Day)	(Year)
Effective:	Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)		(Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE I – Rules and Regulations

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 126 of Sheets

EXHIBIT "D"

Gas Quality Specifications

The gas to be delivered hereunder by Seller at the Point of Delivery shall comply at all times with the following quality specifications:

Heating Value: The gas shall have a total (gross) heating value of not less than nine hundred fifty (950) Btu's per cubic foot and not more than one thousand one hundred (1,100) Btu's per cubic foot, each being expressed on a "dry basis" at 14.65 psi.

Hydrogen Sulfide: The hydrogen sulfide content shall not exceed one-quarter (1/4) grain per one hundred (100) cubic feet of gas.

Mercaptans: The mercaptan sulphur content shall not exceed one (1) grain per one hundred (100) cubic feet of gas.

Total Sulphur: The total sulphur content, including hydrogen sulfide and mercaptans, shall not exceed twenty (20) grains per one hundred (100) cubic feet of gas.

Total Non-Hydrocarbon Gas: The total of all non-hydrocarbon gases shall not exceed 4.0%.

Carbon Dioxide: The carbon dioxide content shall not exceed three percent (3%) by volume.

Oxygen: The oxygen content shall not exceed one-tenth of one percent (0.1 of 1%) by volume, and Seller shall make every reasonable effort to maintain the gas totally free from oxygen.

Nitrogen & Helium: The combined nitrogen and helium content shall not exceed three percent (3%) by volume.

Other: The gas shall contain no carbon monoxide, halogens or unsaturated hydrocarbons and no more than 0.04% of hydrogen.

Liquids: The gas shall be free from water and hydrocarbons in liquid form at the temperature and pressure at which the gas is delivered and, further provided, the gas shall not contain any hydrocarbons which may condense to liquid state under normal pipeline operating conditions and shall in no event contain water vapor in excess of seven (7) pounds per one million (1,000,000) cubic feet of gas.

Issued: January 26, 2012
(Month) (Day) (Year)

Effective: Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE I – Rules and Regulations

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Freedom From Objectionable Matter: The gas shall be commercially free from PCB's, objectionable odors, sand, dust, gums or other solid, liquid or gaseous matters including any additives or diluents which may be injurious to conventional pipeline materials or which may otherwise interfere with the transmission, distribution or commercial utilization of said gas.

Temperature: The gas shall not be at a temperature of less than forty degrees (40°) Fahrenheit nor more than one hundred twenty degrees (120°) Fahrenheit.

Negative Pressure: The gas shall not be produced at or encounter before delivery a pressure of less than atmospheric pressure.

Heavier Hydrocarbons: The heavier hydrocarbon content shall not exceed 0.05 gallons/Mcf of C_6 and heavier hydrocarbons.

Hydrocarbons Dewpoint: The hydrocarbon dewpoint shall not exceed 5° F at delivery pressures or lower. Note that maximum hydrocarbon dew point may be lower if downstream delivery contracts include lower maximum hydrocarbon dew point requirements.

Bacteria: The gas shall be free of bacteria.

Radon Gas: The Gamma radiation in the gas shall not exceed 50 microroentgens/hr.

Lead: The Lead 210 content shall not exceed 30 PCi/gram.

Other Heavy Metals: All other heavy metals shall not exceed 150 Pi/gram. Arsenic, Mercury, Silver, Barium, Cadmium, Chromium and Selenium shall be less than 5 mg/Liter.

All gas shall be free from objectionable odors, PCB's, dust, hydrocarbon liquids, water or other solid or liquid matters, any microbiological organism, gum, gum-causing constituents, active bacteria or bacterial agent capable of contributing to or causing corrosion and/or operational and/or other problems. Microbiological organisms, bacteria or bacterial agents include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (APB).

Issued:	January	26,	2012
	(Month)	(Day)	(Year)
Effective:	Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)		(Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE II. Schedule of Service Fees

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding
shall modify the tariff as shown hereon.

Sheet 1 of 3 Sheets

SCHEDULE II - SCHEDULE OF SERVICE FEES

Applicability: Service Fees may be collected by Company from its Customers under the circumstances and in the amount hereinafter set forth:

A. METER READING FEE

In the event the Customer does not furnish a required meter reading for two (2) consecutive billing periods, the Company may read the Meter and the Company will require a Meter Reading fee of $5.00.

B. WORTHLESS CHECK CHARGE

The Company may require for each Customer check returned for insufficient funds a Worthless Check Charge not to exceed the amount provided by K. S. A. 21-3707 or as thereinafter amended ($30.00).

C. INSUFFICIENT FUNDS CHARGE (ELECTRONIC TRANSACTION)

The Company may require for each Customer's electronic transaction reversed due to a lack of funds available an Insufficient Funds Charge not to exceed $30.00.

D. COLLECTION CHARGE

When collection is made at the Customer's premises to avoid disconnection of Gas Service or Gas Service is discontinued because of non-payment of a Gas Service bill, the Company will require a Collection Charge of $8.00.

E. DISCONNECTION CHARGE ~~DURING NORMAL BUSINESS HOURS~~

When Gas Service is disconnected for any of the reasons stated in Schedule I, Section 5, A. 1. of the Company Rules and Regulations, except when requested by the Customer, the Company will require a Disconnection Charge of $~~8~~15.00 During Normal Business Hours/$20.00 Other Than Normal Business Hours, but not both a collection charge and a disconnection charge.

F. INITIATE OR RECONNECT CHARGES~~RECONNECTION CHARGES~~ DURING NORMAL BUSINESS HOURS

Issued:	~~May~~ 26~~12~~,	January 20~~08~~12	
	(Month)	(Day)	(Year)
Effective:	~~July~~ ~~2008~~Upon Commission Approval	~~8,~~	
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)		(Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE II. Schedule of Service Fees

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

When Gas Service is initiated or reconnected, the Company will require a charge of $20.00 During Normal Business Hours/$25.00 Other Than Normal Business Hours.~~When Gas Service is reconnected during normal business hours, except when disconnected pursuant to Customer=s request, the Company will require a Reconnection Charge of $15.00.~~

G. INITIATE OR RECONNECT CHARGES~~RECONNECTION CHARGE~~-MULTIPLE UNIT BUILDING OR MULTI-FAMILY DWELLING UNITS

When Gas Service is reconnected, except when disconnected pursuant to Customer's request, to multiple unit buildings or multi-family dwelling units served by one Meter, a reconnection charge shall be made which shall be the greater of a) $20.00 During Normal Business Hours/$25.00 Other Than Normal Business hours (b) $4.00 During Normal Business Hours/$5.00 Other Than Normal Business Hours, per building or family dwelling unit.

Formatted: Indent: Left: 1"

~~When Gas Service is reconnected, except when disconnected pursuant to Customer=s request, to multiple unit buildings or multi-family dwelling units served by one Meter, a reconnection charge shall be made which shall be the greater of (a) $15.00, or (b) $3.00 per building or family dwelling unit.~~

H. METER TEST CHARGES

The Company, upon written request by a Customer, shall test the accuracy of the Meter used by the Customer provided the Meter has not been tested by the Company within one year previous to such test. The Customer will be required by the Company to make an advance deposit to cover the cost of the Meter test, which shall be in the following amounts:

1. Diaphragm displacement meters having a rated capacity of 300 cubic feet per hour or less $10.00.

2. Diaphragm displacement meters have a rated capacity of exceeding 300 cubic feet per hour and not exceeding 1,000 cubic feet per hour $37.50.

3. Diaphragm displacement meters having a rated capacity exceeding 1,000 cubic feet per hour $50.00.

4. Rotary displacement meters-No charge.

5. Orifice meters-No charge.

Issued: ~~May~~ January ~~26~~12, ~~2008~~12
(Month) (Day) (Year)

Effective: ~~July 8, 2008~~Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE II. Schedule of Service Fees

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

I. TEMPORARY SERVICE FEE

Upon request of a Customer, the Company will provide a temporary service and a minimum charge of not less than $25.00 shall be paid for such temporary service

J. CREDIT/DEBIT/ATM CARDS

The Authorized Pay Agent may charge the customer an additional fee of $3.95 per $500 for the use of credit/debit/ATM cards.

K. TRIP CHARGE

When Company personnel and equipment have been utilized for non-emergency type services, a $30.00 Trip Charge will be required.

L. ELECTRONIC MEASUREMENT TRIP CHARGE

When Company personnel and equipment have been utilized in responding to electronic measurement services, a $30.00 Trip Charge will be required.

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Issued: ~~May~~ January ~~26~~12, ~~2008~~12
(Month) (Day) (Year)

Effective: ~~July~~ ~~8,~~ ~~2008~~Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 24 Sheets

Field Code Changed

SECTION 1 – GENERAL

A. COUNTIES/COMMUNITIES SERVED:

County	City
Allen	Elsmore
Allen	Savonburg
Barber	Hazelton
Bourbon	Fort Scott
Bourbon	Fulton
Bourbon	Hammond
Bourbon	Redfield
Chase	Cottonwood Falls
Chase	Strong City
Chautauqua	Cedar Vale
Chautauqua	Chautauqua
Chautauqua	Elgin
Chautauqua	Hewins
Chautauqua	Niotaze
Chautauqua	Peru
Chautauqua	Sedan
Coffey	Burlington
Coffey	LeRoy
Coffey	New Strawn
Crawford	McCune
Dickinson	Herington
Douglas	Eudora
Douglas	Lawrence
Elk	Elk Falls
Elk	Grenola
Elk	Longton

Formatted: Right

Issued: ~~July~~ January ~~126,~~ ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August~~ ~~1,~~ ~~2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 2 of 24 Sheets

Field Code Changed

Elk	Moline

County	City
Grant	Hickock
Grant	Ulysses
Greenwood	Eureka
Greenwood	Fall River
Greenwood	Hamilton
Greenwood	Neal
Hamilton	Kendall
Hamilton	Syracuse
Harper	Anthony
Harper	Danville
Johnson	De Soto
Johnson	Gardner
Johnson	Lenexa
Johnson	New Century
Johnson	Olathe
Johnson	Overland Park
Johnson	Shawnee
Johnson	Spring Hill
Labette	Bartlett
Labette	Chetopa
Labette	Edna
Labette	Mound Valley
Leavenworth	Basehor
Leavenworth	Easton
Leavenworth	Jarbalo
Leavenworth	Leavenworth
Leavenworth	Linwood

Formatted: Right

Issued: ~~July 126, 2010~~ January 2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~ Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Field Code Changed

Linn	Mound City
Linn	Pleasanton
Linn	Prescott

County	City
Marion	Aulne
Marion	Florence
Marion	Hillsboro
Marion	Lincolnville
Marion	Lost Springs
Marion	Marion
Marion	Marion Lake
Marion	Peabody
Marion	Pilsen
Marion	Ramona
Marion	Tampa
Miami	Hillsdale
Montgomery	Caney
Montgomery	Coffeyville
Montgomery	Dearing
Montgomery	Elk City
Montgomery	Havana
Montgomery	Independence
Montgomery	Liberty
Montgomery	Sycamore
Montgomery	Tyro
Morris	Council Grove
Morris	Delavan
Morris	White City
Morris	Wilsey

Formatted: Right

Issued: ~~July~~ January ~~126,~~ ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF	Index No.
THE STATE CORPORATION COMMISSION OF KANSAS	
ATMOS ENERGY CORPORATION (Name of Issuing Utility)	SCHEDULE IV: Sales and Transportation Rates
ENTIRE SERVICE AREA (Territory to which Schedule is applicable)	
No Supplement or separate understanding shall modify the tariff as shown hereon.	Sheet 4 of 24 Sheets

Field Code Changed

Morton	Unincorporated Irrigation
Neosho	Galesburg
Neosho	Morehead
Neosho	Stark
Neosho	Thayer

County	City
Ness	Bazine
Ness	Ness City
Rush	Alexander
Rush	McCracken
Stanton	Johnson City
Stanton	Manter
Stevens	Unincorporated Irrigation
Sumner	Caldwell
Sumner	Hunnewell
Sumner	South Haven
Wilson	Altoona
Wilson	Benedict
Wilson	Buffalo
Wilson	Fredonia
Wilson	LaFontaine
Wilson	Neodesha
Woodson	Toronto
Woodson	Yates Center
Wyandotte	Bonner Springs
Wyandotte	Edwardsville
Wyandotte	Kansas City

B. COUNTIES SERVED AT WHOLESALE: NONE

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 5 of 24 Sheets

Field Code Changed

C. RATES APPLICABLE TO WHOLESALE CUSTOMERS: NONE

Formatted: Right

Issued:	~~July~~ January ~~1~~26,	~~2010~~2012	
	(Month)	(Day)	(Year)
Effective:	~~August~~ ~~1,~~ ~~2010~~Upon Commission Approval		
	(Month)	(Day)	(Year)
By:	~~Karen P. Wilkes~~ VP-Reg & Public Affairs		
	(Signature of Officer)		(Title)

Field Code Changed

SECTION 2 – FIRM SALES SERVICE

A. Residential Sales Service (Rate Schedule 910)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to residential customers at a single location.

2. MONTHLY BILL

a. Facilities Charge: $19.00~~$15.50~~ per month

b. Commodity Charge: $0.15576~~.12953~~ per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA, WNA Schedules, and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

5. 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 service, the Company

Formatted: Right

Field Code Changed

may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

Formatted: Right

Field Code Changed

B. Commercial/Public Authority (General) Sales Service (Rate Schedule 915)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to commercial and public authority customers at a single location.

2. MONTHLY BILL

a. Facilities Charge: $$44.00~~37.00~~ per month

b. Commodity Charge: $0.15576~~.12953~~ per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA, WNA Schedules and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas

5. 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 service, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

Formatted: Right

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 9 of 24 Sheets

Field Code Changed

C. School Sales Service (Rate Schedule 920)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to state, county, city and private educational institutions or universities constructed before January 1, 1995 at a single location.

2. MONTHLY BILL

a. Facilities Charge: $44.00~~37.00~~ per month

b. Commodity Charge: $0.15576~~.12953~~ per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA, WNA Schedules and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Field Code Changed

D. Industrial Sales Service (Rate Schedule 930)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to industrial customers at a single location.

2. MONTHLY BILL

a. Facilities Charge: $90.00~~70.00~~ per month

b. Commodity Charge: $0.15576~~.12953~~ per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA Schedules and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 11 of 24 Sheets

Field Code Changed

E. Small Generator Sales Service (Rate Schedule 940)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to commercial customers, at a single location, for separately metered electric generators of less than 20 kilowatts of capacity.

2. MONTHLY BILL

a. Facilities Charge: $44.00~~37.50~~ per month

b. Commodity Charge: $0.15576~~.1500~~ per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA Schedules.

The minimum bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF	Index No.
THE STATE CORPORATION COMMISSION OF KANSAS	
ATMOS ENERGY CORPORATION (Name of Issuing Utility)	SCHEDULE IV: Sales and Transportation Rates
ENTIRE SERVICE AREA (Territory to which Schedule is applicable)	
No Supplement or separate understanding shall modify the tariff as shown hereon.	Sheet 12 of 24 Sheets

Field Code Changed

F. Irrigation Engine Sales Service (Rate Schedule 965)

1. APPLICABILITY

   Available in and around the communities specified in the Section 1 A. to engine irrigation customers at a single location.

2. MONTHLY BILL
   a. Facilities Charge: $60.00~~49.00~~ per month
   b. Commodity Charge: $0.09600~~.08100~~ per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA Schedules and Customer Utilization Adjustment.

   The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

   Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

   Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Issued:	~~July~~ January ~~1~~26,	~~2010~~2012	
	(Month)	(Day)	(Year)
Effective:	~~August~~	~~1,~~	
	~~2010~~Upon Commission Approval		
	(Month)	(Day)	(Year)
By:	~~Karen P. Wilkes~~	VP-Reg & Public Affairs	
	(Signature of Officer)	(Title)	

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 13 of 24 Sheets

Field Code Changed

SECTION 3 - INTERRUPTIBLE GAS SALES SERVICE

A. Large Industrial Sales Service (Rate Schedule 955)

1. APPLICABILITY

a. This rate schedule is available at the Company's option to any large volume user using at least 220,000 Ccf annually or customers using 1,000 Ccf per day during off peak periods. Customer shall have and maintain adequate standby facilities and fuel in order that gas deliveries may be curtailed in whole or in part at any time upon thirty minutes notice.

b. Those customers who were transporting gas on the Company's Rate Schedule 960 prior to September 1, 1995 will be grandfathered to this rate schedule.

c. Customers electing this service after September 1, 1995 must use at least 220,000 Ccf annually to continue service under this schedule. The Company may waive this condition if unusual circumstances exist. If the same customer uses less than 220,000 Ccf annually after the second year of service, the customer will be changed to Rate Schedule 930 or Rate Schedule 950.

2. CHARACTER OF SERVICE

a. Natural gas, with a heating value of approximately 100,000 BTU per Ccf, supplied through a single meter, at standard equipment utilization pressure, or such higher delivery pressure as approved by Company.

b. "Optional Gas" is the quantity of gas Customer agrees to purchase and Company agrees to deliver in any one day when Company has gas available and when Company's distribution system is suitable for such delivery.

c. "Firm Gas" is the daily quantity of gas delivered to a customer within that Customer's contract demand quantity, if any. Customers electing to receive firm gas under this rate schedule shall contract for a minimum of 500 Ccf per day. Customers served under Rate Schedule 950 prior to September 1, 1995 with a quantity of less than 500 Ccf shall be grandfathered. Firm gas is not subject to curtailment, except as described under the Priority of Service section of this rate schedule, and only then if all optional gas service has been curtailed first.

Formatted: Right

Issued:	~~July~~ January ~~1~~26,	~~2010~~2012	
	(Month)	(Day)	(Year)
Effective:	~~August~~ ~~1,~~ ~~2010~~Upon Commission Approval		
	(Month)	(Day)	(Year)
By:	~~Karen P. Wilkes~~ VP-Reg & Public Affairs		
	(Signature of Officer)		(Title)

Field Code Changed

d. Company is also relieved of its obligation to deliver any gas under this schedule in the event of force majeure. Any curtailments which may be necessary under this rate schedule shall be made only after having given at least 30 minutes notice by telephone or otherwise unless due to reasons of force majeure.

3. INTERRUPTION AND CURTAILMENT OF OPTIONAL SERVICE:

a. Optional gas deliveries to customers served on this schedule may be interrupted or curtailed at any time such interruption or curtailment is necessary in order for Company to continue to supply the gas requirements of its other customers at such time. The Company will endeavor to notify in advance customers served on this schedule whenever a curtailment or interruption is required, and each such customer shall curtail his use of gas at the time and to the extent requested by the Company. Interruptions and curtailments may vary from time to time among customers, but shall be as equally apportioned as practicable.

b. "Unauthorized Use" is defined as the taking of any volume of optional gas by Customer during any period when the use of optional gas is curtailed in accordance with notice given by Company. Company shall bill, and Customer shall pay $2.50 per Ccf for all volumes of unauthorized use gas in addition to the rate billed under this schedule.

4. CONTRACT

a. Customer shall contract for service hereunder for a term of not less than one (1) year. Upon the expiration of any contract term, the contract shall be automatically renewed for a period of one (1) year. At any time following the first contract year, service may be terminated by either party following at least six (6) months notice to the other party.

b. A day, as used herein, shall be defined as a period of 24 consecutive hours designated by Company to coincide with applicable pipeline contract.

5. RATE

a.	Facilities Charge	$325.00~~275.00~~	per month
b.	Commodity Charge	$0.08200 ~~.07140~~	First 20,000 Ccf per month
		$0.07400 ~~.06340~~	All over 20,000 Ccf per month

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Field Code Changed

6. DEMAND RATE

a.	Demand Rate	The sum of the reservation costs for which the Company has contracted with Southern Star Central Gas Pipeline, Inc., per Ccf of Contract Demand.
b.	Daily Demand Rate	The Demand Rate divided by 30.4 days, per Ccf per day for all gas in excess of the Contract Demand level.

a.	Demand Rate	The sum of the reservation costs for which the Company has contracted with Southern Star Central Gas Pipeline, Inc., per Ccf of Contract Demand.
b.	Daily Demand Rate	The Demand Rate divided by 30.4 days, per Ccf per day for all gas in excess of the Contract Demand level.

7. MONTHLY BILL

The minimum monthly bill applicable at single address or location shall be the sum of the Facility Charge and the Demand Charge, Daily Demand Charge and the Commodity Charge as follows:

a. The Demand Charge shall be the product of the demand level nominated by the Customer and the Demand Rate.

b. The Daily Demand Charge shall be the product of the unauthorized volumes taken by Customer when curtailed by Company under this rate schedule on each day during the billing period in excess of the demand level nominated by the Customer and the Daily Demand Rate.

Formatted: Right

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 16 of 24 Sheets

Field Code Changed

c. The Commodity Charge shall be the product of all volumes delivered under this rate during the billing period and the Commodity Rate.

Formatted: Right

Issued:	~~July~~ January ~~1~~26,	~~2010~~2012	
	(Month)	(Day)	(Year)
Effective:	~~August~~ ~~1,~~ ~~2010~~Upon Commission Approval		
	(Month)	(Day)	(Year)
By:	~~Karen P. Wilkes~~ VP-Reg & Public Affairs		
	(Signature of Officer)		(Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 17 of 24 Sheets

Field Code Changed

8. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

9. PURCHASED GAS ADJUSTMENT

The above rate is subject to increase or decrease to reflect changes in purchased gas costs in accordance with the provisions of the Company's non-firm PGA.

10. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Issued: ~~July~~ January ~~12~~6, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Field Code Changed

B. Economic Development Sales Service (Rate Schedule 960)

1. APPLICABILITY

a. Service under this Schedule is available to customers engaged in the manufacturing process at discounted or incentive rates. Customers engaged in retailing goods and services to the public are not eligible for this service. To be eligible for service under this schedule certain conditions must be met by the customer. Existing customers served under another rate schedule to be eligible for service under this rate schedule must contract for sufficient natural gas demand to produce an increase in consumption of 135,000 Ccf annually. New customers served under this rate schedule to be eligible must contract for at least 270,000 Ccf annually. Customers served under this Rate Schedule must demonstrate increased employment.

b. This Schedule is intended to allow the Company to offer incentive or discount type rates designed to enhance the Company's system utilization while encouraging industrial development within the Company's service areas.

2. SPECIAL TERMS AND CONDITIONS

a. A contract shall be executed by the customer for a minimum of 4 years. The contract shall specify the customer's natural gas requirements.

b. To receive service under this rate schedule, the customer's written application to the Company shall include sufficient information to permit the Company to determine the customer's eligibility.

c. Qualifying consumption shall result from an increase in business activity and not merely from the resumption of normal operations following a period of abnormal operating conditions. If in the Company's opinion an abnormal operating period has occurred as a result of strike, equipment failure, or any other abnormal condition during the twelve (12) month period prior to the date of the application by the customer for service under this rate schedule, the Company shall adjust the customer's consumption to eliminate any abnormal condition. The Company through use of historical data shall determine "Base Load" for existing customers. Volumes used in excess of "Base Load" shall be considered "Qualifying Consumption" and eligible under this Schedule. Loads which are or have been served by the Company during all or part of the twelve (12) month period prior to service under this rate

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Field Code Changed

schedule, and which are relocated to another metering point within the Company's service area, shall not qualify for this rate schedule.

d. The existing facilities of the Company must be adequate in the judgment of the Company to supply the new or expanded natural gas requirements. If construction of new or expanded local facilities by the Company is required, the customer may be required to make a Contribution in Aid of Construction for the installed cost of such facilities. The Company will evaluate the customer's request for service and determine the necessity of a contribution for construction of facilities based on the Extension of Service provisions of the General Terms and Conditions of the Company's filed tariff. The Company shall review the Customer's consumption each year to determine whether the Customer has fulfilled their projected usage requirement to remain eligible for service under this rate schedule.

3. FACILITY CHARGE

a. A monthly facility charge equal to the otherwise applicable companion rate schedule is payable regardless of the usage of gas.

b. The following adjustment factors will be applied to the "Qualifying Consumption" and based on the rate schedule which would apply to the Customer absent this rate schedule. The Customer may elect to begin service under this Schedule on the 1st month or 13th month of service with the Company

Billing Months In Contract Year	Adjustment Factor
1st Through 12th	75%
13th Through 24th	75%
25th Through 36th	75%
37th Through 48th	75%
After 48 Months	100%

4. MINIMUM MONTHLY BILL

The minimum monthly bill shall be the monthly Facility Charge plus the Monthly Demand Charge, if any.

Formatted: Right

Field Code Changed

5. PURCHASED GAS ADJUSTMENT

The above rate is subject to increase or decrease to reflect changes in purchased gas costs in accordance with the provisions of the Company's firm or non-firm PGA, whichever is the companion to the otherwise applicable sales rate.

6. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 21 of 24 Sheets

Field Code Changed

SECTION 4 - TRANSPORTATION SERVICE

A. General Service Firm Transportation Service (Rate Schedule FT900)

1. AVAILABILITY

See Schedule I, Section 12 A – Transportation Services

2. MONTHLY BILL

Companion Sales Schedule	Facility Charge	Commodity Charge
915, 920	$90.00 ~~70.00~~	$0.15576~~.12953~~ / ccf + take-or-pay costs set for on Sheet 1 of 1
~~925~~	~~$90.00 70.00~~	~~$0.15576.12953 / ccf + take-or-pay costs set for on Sheet 1 of 1~~
930	$90.00 ~~70.00~~	$0.15576~~.12953~~ / ccf + take-or-pay costs set for on Sheet 1 of 1

The minimum monthly bill shall be the facility charge and the demand charge, if any.

3. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the applicable companion sales rate schedule conditions and to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Constructions of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 22 of 24 Sheets

Field Code Changed

B. Interruptible Transportation Service (Rate Schedule IT900)

1. AVAILABILITY

See Schedule I, Section 12 A – Transportation Services

2. MONTHLY BILL

Companion Sales Schedule	Facility Charge	Commodity Charge
955	$325.00~~275.00~~	$0.08200 ~~.07140~~/ ccf, first 20,000 $0.07400 ~~.06340~~/ ccf, greater than 20,000 + take-or-pay costs set for on Sheet 1 of 1

The minimum monthly bill shall be the facility charge and the demand charge, if any.

3. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the applicable companion sales rate schedule conditions and to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Constructions of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Issued:	~~July~~ January ~~1~~26, ~~2010~~2012		
	(Month)	(Day)	(Year)
Effective:	~~August~~ ~~1,~~ ~~2010~~Upon Commission Approval		
	(Month)	(Day)	(Year)
By:	~~Karen P. Wilkes~~ VP-Reg & Public Affairs		
	(Signature of Officer)		(Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 23 of 24 Sheets

Field Code Changed

C. Interruptible Negotiated Transportation Service (Rate Schedule IT-NEG)

1. AVAILABILITY

a. Gas service under this rate schedule is available to those customers having alternate fuel capability at the Company's discretion. This rate schedule is designed to permit the Company to meet alternate fuel and/or gas to gas competition. Service under this rate schedule shall be fully optional and subject to curtailment prior to optional customers.

b. The intent of this rate schedule is to provide the Company flexibility to provide service at negotiated rates when the otherwise applicable tariff rates are noncompetitive. The Company will make every effort to maximize recovery of base margins and fixed components of the purchased gas adjustment.

c. The Company's decision to enter into a discounted service agreement and the amount of the discount will be subject to review by the Commission at the Company's next rate case for the purpose of setting future rates. Discounted service agreements shall be granted only to retain or obtain a Customer who has a credible competitive alternative available. The amount of the discount from the maximum approved tariff rate shall be the least necessary to retain or obtain the customer.

d. In situations where the discounted service agreement involves a company affiliate, Company shall file with the Commission a copy of the agreement with all supporting documentation and worksheets, within 10 days of the date of the agreement.

2. MONTHLY BILL

a. Facilities Charge $325.00~~275.00~~ per month
b. Commodity Charge

The rates charged under this rate schedule shall be negotiated on a per customer basis. The Company may require supporting documents from the end-user certifying that the cost of available alternate supply is less than the otherwise applicable tariff rate. The maximum charge shall not exceed the sales rate schedule under which the customer would otherwise be charged. In no event shall the price negotiated be less than the incremental costs of serving the Customer plus $0.001/Ccf.

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August 1, 2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Field Code Changed

The minimum monthly bill shall be the monthly facility charge.

3. UNAUTHORIZED GAS

"Unauthorized Use" is defined as the taking of any volume of optional gas by Customer during any period when the use of optional gas is curtailed in accordance with notice given by Company. Company shall bill, and Customer shall pay $2.50 per Ccf for all volumes of unauthorized use gas in addition to the rate billed under this schedule.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Formatted: Right

Issued: ~~July~~ January ~~1~~26, ~~2010~~2012
(Month) (Day) (Year)

Effective: ~~August~~ ~~1,~~ ~~2010~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF **THE STATE CORPORATION COMMISSION OF KANSAS** ATMOS ENERGY CORPORATION (Name of Issuing Utility) ENTIRE SERVICE AREA (Territory to which Schedule is applicable)	Index No. SCHEDULE V: Purchased Gas Adjustment (PGA)
No Supplement or separate understanding shall modify the tariff as shown hereon.	Sheet 1 of 6 Sheets

Field Code Changed

SCHEDULE V – PURCHASED GAS ADJUSTMENT (PGA)

SECTION 1 - PURCHASED GAS COST ADJUSTMENT PROCEDURE

A. RATE SCHEDULES COVERED

All of the Company's sales rate schedules shall be subject to a purchased gas cost adjustment:

Description	Combined Kansas Rate Division and Southwest Kansas Rate Division
Firm Sales Service including: Residential, Commercial, Public Authority, School, Irrigation Engine, Agricultural Service, and Small Industrial.	910, 915, 920, 930, 940, 960, 965
Interruptible Sales Service including: School, Small Industrial, Large Industrial, and Economic Development.	955, 960

B. COMPUTATION FORMULA

1. The Company's rates for gas service are subject to adjustment for change in the average cost of gas from all sources of supply purchased. At the end of the twelve-month period ending August, the Company will project the average cost of gas for the twelve months ending August 31 of the following year. If at any time during this twelve month period the Company experiences a change or changes in supplier rates or in sources of supply, the cumulative effect of which change or changes is to produce an increase or decrease in the new projected effective rate for purchased gas from all suppliers of at least $.010 per Ccf, then an adjusted average rate shall be determined. The annual cost of gas projection and any revised projections throughout the year will be computed using the following formula:

$$\frac{P + E + S + C}{V} = \text{Adjustment}$$

Where:

P = The estimated total dollar cost of purchased gas to be sold calculated by summing the products of the most recent unit cost of purchased gas from each supplier and the estimated unit purchases from each supplier for the twelve month period ending August 31. In the event that changes in the rates paid for purchased gas will take place within the current twelve month period ending August 31, as specified by

Formatted: Right

Issued:	~~May~~ January	~~12~~6,	~~2008~~2012
	(Month)	(Day)	(Year)
Effective:	~~November~~	~~1,~~	~~2008~~Upon Commission Approval
	(Month)	(Day)	(Year)
By:	~~Karen P. Wilkes~~		VP-Reg & Public Affairs
	(Signature of Officer)		(Title)

Field Code Changed

contract provisions currently in effect, the estimated average unit cost of purchased gas from each supplier for the current twelve month period ending August 31, may be used in the calculation in place of the most recent unit cost.

E = Estimated net cost (positive or negative) arising from exchange gas transactions that are expected to occur during the twelve month period ending August 31 (Account 806), not including storage gas transactions.

S = Estimated cost of stored gas to be withdrawn from storage (Account 808) and sold.

V = The estimated sales volume in Ccf for the twelve month period ending August 31. (If the actual sales volume reflects a line loss factor greater than the limit value, restatement of sales volume, based on the limit value for line loss, shall be required.)

C = Cost of Company owned storage facilities. Cost shall be estimated and recovered based on the latest twelve months actual O&M, Depreciation ~~n~~and return on investment (return calculated based on last rate case factors).

Volumes sold under Rate Schedule 955, and 960 shall not be billed the demand costs, or its equivalent, contained in the PGA computed in accordance with the above-stated formula, but shall be billed the remaining costs contained in the PGA formula. In addition to the PGA less demand costs, or its equivalent, Rate Schedule 955 and 960 shall also have applied to the volumes sold the sum of the Southern Star Central Gas Pipeline, Inc.'s maximum ITS-P and ITS-M commodity rates, adjusted for fuel reimbursement percentages, as set forth in Southern Star Central Gas Pipeline, Inc.'s tariff on file with the Federal Energy Regulatory Commission.

C. COMPUTATION PERIOD

The computation period shall be the subsequent twelve month period ending August 31.

D. COMPUTATION FREQUENCY

The computation shall be made annually or each time a change or changes occur in supplier rates or sources of supply, the cumulative effect of which change or changes is to produce an increase or decrease in the new effective rate paid for purchased gas by at least $.010/Ccf.

E. COSTS INCLUDED

Formatted: Right

Field Code Changed

The formula includes only costs which are properly included in FERC Accounts 800, 801, 802, 803, 804, 858, applicable to Kansas; 805, 806, 808, and 809.

F. SETTLEMENT PROVISIONS

Subsequent to the effective date of this clause, the Company shall maintain a continuing monthly comparison of the actual (as billed) cost of gas as shown on the books and records of the Company, exclusive of refunds, and the cost recovery for the same month calculated by applying to the volumes sold during said month the purchased gas cost adjustments calculated pursuant to these purchased gas cost adjustment provisions. For each twelve month period ended August 31, the differences of the comparisons described above including any balance or credit for the previous year shall be accumulated to produce a cumulative balance of over-recovered or under-recovered costs.

An "Actual Cost Adjustment" (ACA) shall be computed by dividing the cumulative balance of under-recovered or over-recovered costs by the volume of total sales during the twelve month period ending on that date. This adjustment shall be rounded to the nearest $.0001 per Ccf and applied to sales billed on or after the first day of the month following the month in which the adjustment has been approved by the Commission. The "Actual Cost Adjustments" shall remain in effect until superseded by subsequent "Actual Cost Adjustments" calculated according to this provision.

The Gas Cost portion of uncollectible accounts is recoverable through the ACA. The cumulative balance of over-recovered or under-recovered costs shall include the Gas Cost portion of uncollectible PGA customer accounts billed under this Schedule during the preceding Computation Year and which remain unpaid. The uncollectible amounts included in the annual ACA computation shall not contain interest or collection fees or charges. This sub-component of the ACA will be a separate line item on Sheet 1 of the Purchased Gas Adjustment.

G. CAPACITY RELEASE

The Company shall forecast, on a monthly basis, the capacity release credits expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly Capacity Release Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total Capacity Release Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual capacity release credits received and the capacity release credits distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated Capacity Release Balance, that is, a cumulative balance of under or over distributed credits. An Accumulated Capacity Release Factor will be calculated annually by dividing the accumulated balance of under or over distributed credits by the volume of

Formatted: Right

Field Code Changed

actual sales during the twelve month period ending August 31. The Accumulated Capacity Release Factor will be added to the Monthly Capacity Release Factor to equal the Total Capacity Release Factor. The Accumulated Capacity Release Balance will be adjusted by the monthly capacity release under/over disbursements.

H. OVERRUN PENALTIES

Overrun penalties applicable to the Company's Kansas jurisdiction shall be separately accumulated and shall be administered in compliance with the provisions contained in the Commission Order in Docket No. 190,061-U. The Company shall maintain a continuing monthly comparison of the actual penalties received (applicable to its Kansas jurisdiction) and the amount recovered from its customers. The differences of the comparisons described above shall be accumulated to produce an Accumulated Penalty Balance, that is, a cumulative balance of under or over recovered penalties. An Accumulated Penalty Recovery Factor will be calculated annually by dividing the accumulated balance of under or over recovered penalties by the volume of actual sales during the twelve month period ending August 31. The Accumulated Penalty Recovery Factor will be applied to the Purchased Gas Cost Factor each month. The Accumulated Penalty Balance will be adjusted by the monthly penalty under/over recovery.

I. REPORTING REQUIREMENTS

The Company shall submit to the Commission purchased gas cost filings at least 15 days before the filing is to be effective. Purchased gas cost filings and cost adjustment reports shall use the format prescribed by the Commission.

J. LINE LOSS LIMITATIONS

The Company shall compute one actual line loss for the entire State of Kansas . In the event that the actual line loss (unaccounted for gas) statistic for the computation period exceeds the line loss limit of 4%, the Company will compute the purchased gas adjustment using the limit value rather than the actual operating statistic value.

SECTION 2 - PURCHASED GAS COST REFUND ADJUSTMENT PROCEDURE

A. REFUND PROVISION

1. For the purpose hereof, unless the Kansas Corporation Commission shall otherwise order, refunds or a balance in the refund account in excess of $.002 per Ccf for purchased gas

Formatted: Right

Field Code Changed

from all suppliers (including interest from the suppliers) in a rate area received by Company from charges paid for natural gas resold to its customers, shall be refunded to such customers as a reduction in the Purchased Gas Adjustment. Within ninety (90) days of the receipt of a refund in excess of $.002 per Ccf for purchased gas from any supplier or the balance of the refund account reaching the equivalent of $.002 per Ccf for purchased gas from all suppliers, the Company shall file with the Commission and propose to make effective, the appropriate Purchased Gas Adjustment reflecting the decrease and an associated statement showing the computation of the refund adjustment.

2. The refund adjustment per Ccf shall be determined by dividing the appropriate refund amount by the estimated Ccf sales to the rate area as shown on Line 6, Sheet KCC Form PGA-1. The amount of the unit refund adjustment shall be computed to the nearest $.00001 per Ccf.

3. The length of the refund period shall generally be twelve (12) months, except that each refund period may be lengthened or shortened by the Company to avoid a refund materially above or below the refundable amount.

4. After the refunding period is completed, the difference between the refund(s) received from the Company's suppliers and the amount refunded to the respective rate area customers shall be determined and said difference retained in the refund account until such time as a subsequent refund is received from such suppliers. The balance in said refund account shall be added to any subsequent refund before computing a new refund adjustment.

5. In the event any refund received from the Company's supplier is less than the equivalent of $.002 per Ccf for purchased gas for a rate area, said refund shall be credited to the refund account. The credit balance in said account, exclusive of those amounts which have been included in the calculation of refunds then in progress, shall be accumulated to the equivalent of $.002 per Ccf for purchased gas before commencing a subsequent refund as hereinabove provided.

SECTION 3 - PURCHASED GAS COST SURCHARGES

A. Gas Hedge Program

The Company shall operate its Gas Hedge Program pursuant to the relevant order in Docket No. 05-ATMG-617-HED. Costs and revenues associated with any purchase or sale of straight call options, and other alternative risk management strategies, such as call spreads, the net balance of which shall not exceed approved annual budget amount. The estimated net balance shall be

Formatted: Right

Form RF	Index No.
THE STATE CORPORATION COMMISSION OF KANSAS	
ATMOS ENERGY CORPORATION (Name of Issuing Utility)	SCHEDULE V: Purchased Gas Adjustment (PGA)
ENTIRE SERVICE AREA (Territory to which Schedule is applicable)	
No Supplement or separate understanding shall modify the tariff as shown hereon.	Sheet 6 of 6 Sheets

Field Code Changed

recovered as a separate cost component during the months of April through October each year from all PGA customers except irrigation. Any over or under recovery, and any of the allowed budget amount not used by the Company over the course of the Hedge Program year, shall be reflected in the Company's next ACA filing. Costs and revenues generated from the settlement of all financial derivatives shall be flowed back as a separate component during the months of November through March to all PGA customers except irrigation. This settlement component shall be a volumetric charge or credit that is calculated each month from November to March by dividing the monthly estimated hedge payoff amount by the sales volume projected to occur during that respective month. The estimated payoff amount shall be adjusted to the actual payoff amount in the following month's calculation of the settlement component. No settlement component will be added if it is less ~~that~~ than $.002 per Ccf, rather the amount will be accumulated until the component results in a rate more than $.002 per Ccf.

Formatted: Right

Issued:	~~May~~ January	~~1~~26,	~~2008~~2012
	(Month)	(Day)	(Year)
Effective:	~~November~~	~~1,~~	~~2008~~Upon Commission Approval
	(Month)	(Day)	(Year)
By:	~~Karen P. Wilkes~~ VP-Reg & Public Affairs		
	(Signature of Officer)		(Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE VIII GSRS Rider

Formatted: Underline

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 1 Sheets

GAS SYSTEM RELIABILITY SURCHARGE RIDER

APPLICABILITY

This rider is applicable to every bill for service provided under each of the Company's sales and transportation rate schedules except where not permitted under a separately negotiated contract with a customer.

RATE

The Gas System Reliability Surcharge (GSRS) shall be applied to each monthly bill. The surcharge shall be as follows:

Residential:	$0.40 per meter per month
Commercial and Public Authority:	$1.29 per meter per month
Schools:	$1.29 per meter per month
Industrial Firm:	$5.78 per meter per month
Small Generator Service:	$5.78 per meter per month
Irrigation Engine:	$3.64 per meter per month
Industrial Interruptible:	$5.78 per meter per month
Transportation:	$17.15 per meter per month

DEFINITIONS AND CONDITIONS

1 The GSRS is intended to recover charges for natural gas public utility plant projects pursuant to K.S.A. 66-2001 through 66-2204.
2 The monthly GSRS charge shall be allocated among customers in the same manner as approved in Docket No. 08-ATMG-280-RTS.
3 The GSRS shall be charged to customers as a monthly fixed charge and not based on volumetric consumption. Such monthly charge shall not Increase more than $0.40 per residential customer over the base rates In effect for the initial filing of a GSRS. Thereafter, each filing shall not Increase the monthly charge for more than $0.40 per residential customer over the most recent filing of a GSRS.
4 At the end of each twelve-month calendar period the GSRS is in effect, the utility shall reconcile the differences between the revenues resulting from a GSRS and the appropriate pretax revenues as found by the Commission for that period and shall submit the reconciliation and a proposed GSRS adjustment to the Commission for approval to recover or refund the difference through adjustments of the GSRS charge.
5 All provisions of this rider are subject to changes made by order of the Commission.

Formatted: Right

Issued: January 26, 2012
(Month) (Day) (Year)

Effective: ~~December 11, 2009~~Upon Commission Approval
(Month) (Day) (Year)

By: ~~Karen P. Wilkes~~ VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IX Customer Rate Stabilization

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 3 Sheets

SCHEDULE IX – CUSTOMER RATE STABILIZATION

APPLICABILITY

This rider is applicable to every bill for service provided under each of the Company's sales and transportation rate schedules except where not permitted under a separately negotiated contract with a customer.

PURPOSE

This mechanism is designed to provide annual earnings transparency. If, through the implementation of the provisions of this mechanism, it is determined that rates should be decreased or increased, then rates will be adjusted accordingly in the manner as set forth herein. The rate adjustments implemented under this mechanism will reflect annual changes in the Company's cost of service and rate base.

DEFINITIONS

1. The **Annual Evaluation Date** shall be the date Company will make its annual filing under this mechanism. The Annual Evaluation Date shall be no later than October 1of each year. This filing shall be made in electronic form where practicable.
2. The **Evaluation Period** is defined as the twelve month period ending June 30 of each year.
3. The **Rate Effective Period** is defined as the twelve month period in which rates determined under this mechanism shall be in effect. The Rate Effective Period shall run from January 1 to December 31.

RATE MECHANISM FILING

The Company shall file with the Commission the schedules specified below for the twelve month period ending June 30 of each year (the "Evaluation Period"), with the filing to be made no later than October 1. The schedules will include the following:

Section 3 - Summary of Rate Base, Operating Income and Rate of Return
Section 4 – Plant in Service
Section 5 - Accumulated Provision for Depreciation and Amortization
Section 6 – Working Capital
Section 7 – Capital and Cost of Money
Section 9 – Test Year and Pro Forma Income Statements
Section 10 – Depreciation and Amortization
Section 11 – Taxes
Section 12 – Allocation Rates
Section 14 – Rate Base Offsets
Section 17 - Revenue, Sales, Customer Data
Section 18 – Proposed Tariffs

Issued:	January	26,	2012
	(Month)	(Day)	(Year)
Effective:	Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)		(Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IX Customer Rate Stabilization

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

The schedules will provide the Company's actual net plant in service, construction work in progress, accumulated deferred income taxes, inventory, working capital, and other rate base components. The schedules shall also show the utility's depreciation expense, operating and maintenance expense, income taxes, taxes other than income taxes, and other components of income for return, its revenues, and its capital structure (based on a 13-month average), cost of debt, overall cost of capital, and return on common equity as approved in the Company's latest general rate case by the Commission.

A. The Company shall establish a regulatory asset to record all costs incurred in connection with the acquisition, installation operation (including related depreciation) for the following natural gas utility plant projects:
   1) Mains, valves, service lines, regulator stations, vaults and other pipeline system components installed to comply with state or federal safety requirements as replacements for existing facilities; main relining projects, service line insertion projects, joint encapsulation projects and other similar projects extending the useful life or enhancing the integrity of pipeline system components undertaken to comply with state or federal safety requirements; and

   2) facility relocations required due to construction or improvement of a highway, road, street, public way or other public work by or on behalf of the United States, this state, a political subdivision of this state or another entity having the power of eminent domain provided that the costs related to such projects have not been reimbursed to the natural gas public utility.

   The Company may record interest on the balance in the regulatory asset account based on the pretax cost of capital last approved for the utility until such amounts are included in and recovered through rates established in a subsequent rate mechanism filing.

B. The filing will include all applicable accounting and pro forma adjustments historically permitted or required by the Commission for the Company.

C. The filing will include pro-forma adjustments to annualize costs and revenue billing determinants for the Rate Effective Period.

D. The filing will include pro-forma or other adjustments required to properly account for atypical, unusual, or nonrecurring events.

E. The filing will include other information from the Company's books and records similar to that provided in response to initial discovery requests issued by Commission staff in a general rate case proceeding.

F. The Company also shall provide a schedule demonstrating the "proof of revenues" relied upon to calculate the proposed rate for the Rate Effective Period. The proposed rates shall conform as nearly as is practicable to the revenue allocation principles approved in the most recent proceeding. The Company shall also include all costs incurred by the Citizens' Utility Ratepayer Board ("CURB") office and the Commission

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Formatted: Indent: Left: 0.75"

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Bullets and Numbering

Formatted: Font: Arial, 10 pt

Formatted: Bullets and Numbering

Issued:	January (Month)	26, (Day)	2012 (Year)
Effective:	Upon Commission Approval (Month)	(Day)	(Year)
By:	(Signature of Officer)		VP-Reg & Public Affairs (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IX Customer Rate Stabilization

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 3 of 3 Sheets

Staff in their review of these annual filings under this mechanism. These costs will be included in the company's operating and maintenance costs.

G. These schedules shall identify the rate adjustments necessary for the Rate Effective Period.
   1) If Company's earnings during the Evaluation Period exceed the latest allowed return on common equity, the Company shall calculate an adjustment to rates to refund the revenue required to achieve a return on equity for the Evaluation Period equal to the return established in the last general rate order.
   2) If Company's earnings are below the allowed return on common equity established in the latest general rate order, the Company shall calculate an adjustment in rates to collect the additional revenue required to increase its return on equity for the Evaluation Period to the allowed percentage.

VERIFICATION

A sworn statement shall be filed by Company's Vice President, Regulatory Affairs for Kansas Operations affirming that the filed schedules are in compliance with the provisions of this mechanism and are true and correct to the best of his/her knowledge, information and belief. No testimony shall be filed.

EVAULATION PROCEDURES

The Commission staff and CURB shall have 60 days to review the Company's filed schedules and issue its recommendation to the Commission for the change in rates under this tariff. The Company will be prepared to provide supplemental information as may be requested to ensure adequate review by the Commission and CURB. The Commission shall propose any adjustments it determines to be required to bring the schedules into compliance with the above provisions.

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Formatted: Indent: Left: 0.25"

Formatted: Bullets and Numbering

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial, 10 pt

Formatted: Font: Arial

Issued:	January (Month)	26, (Day)	2012 (Year)
Effective:	Upon Commission Approval (Month)	(Day)	(Year)
By:	(Signature of Officer)	VP-Reg & Public Affairs	(Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

SCHEDULE I - GENERAL TERMS AND CONDITIONS FOR SERVICE

SECTION 1 - DEFINITIONS

SHEET

SECTION 2 - APPLICATION FOR SERVICE

SECTION 3 - CREDIT AND SECURITY DEPOSIT REGULATIONS

Issued: January 26, 2012
(Month) (Day) (Year)

Effective: Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

SECTION 4 - BILLING AND PAYMENT

SHEET

SECTION 5 - DISCONTINUANCE OF SERVICE

SECTION 6 – CUSTOMER'S SERVICE OBLIGATIONS

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

Issued:	January	26,	2012
	(Month)	(Day)	(Year)
Effective:	Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)	(Title)	

Form RF	Index No.
THE STATE CORPORATION COMMISSION OF KANSAS	
ATMOS ENERGY CORPORATION (Name of Issuing Utility)	INDEX
ENTIRE SERVICE AREA (Territory to which Schedule is applicable)	
No Supplement or separate understanding shall modify the tariff as shown hereon.	Sheet 5 of 7 Sheets

Issued:	January (Month)	26, (Day)	2012 (Year)
Effective:	Upon Commission Approval (Month)	(Day)	(Year)
By:	(Signature of Officer)		VP-Reg & Public Affairs (Title)

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

INDEX

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding
shall modify the tariff as shown hereon.

Issued:	January	26,	2012
	(Month)	(Day)	(Year)
Effective:	Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)		(Title)

SECTION 13 – INTERCONNECTION AGREEMENT

INTERCONNECT AGREEMENT

Re: Interconnect Agreement AE-IA#___; [Company Name] Tap & Measuring Station located in town of__________, State of________ Project #______________

On this _____ day of ______, 20___, ___________________________ ("Interconnector or Company Name"), a __________ corporation and Atmos Energy Corporation, a Texas and Virginia corporation ("Atmos") sometimes referred to herein individually as a "Party" and collectively as the "Parties," Enter into this Interconnect Agreement ("Agreement")AE-IA#________.

WHEREAS, _____________ desires to interconnect with Atmos; and

WHEREAS, the Parties desire to set forth their understanding regarding the design, construction, installation, operation, maintenance, and ownership of certain interconnecting facilities to connect the Interconnector's ________________, located in ___________ County/Parish, _________, to Atmos' natural gas pipeline system located at ____________________.

NOW, THEREFORE, in consideration of the mutual covenants and agreements contained herein, the adequacy and sufficiency of which are acknowledged, the Parties agree as follows:

I. CONSTRUCTION AND INSTALLATION OF THE FACILITIES

A. Interconnector's Responsibilities.

1. Interconnector shall design, construct, install, and may replace at its sole expense, any upstream interconnecting pipeline(s), measuring facility as described on Exhibit "A", gas monitoring equipment, and telemetry, including but not limited to meters, regulators, valves, gas analyzers, shut-in valves, separators, filters, odorizers and such other equipment (collectively, "Measurement Facilities") necessary to connect Interconnector's well (s) to Atmos' Tap Facilities (defined below). All components shall be approved by Atmos. Interconnector will be solely responsible for supplying at its sole expense, electric service to its Measurement Facilities and Atmos' Tap Facilities.

2. Prior to construction of the Measurement Facilities, Interconnector will provide design drawings, sealed by a professional engineer licensed in the state which the Measurement Facilities will be installed, to Atmos for review, and Interconnector will not begin construction until acceptance of the design drawings is received from Atmos. Drawings as shown in Exhibit "B provided by Atmos Energy are conceptual in nature only and are not to be used for final construction".
3. Upon completion of construction of the Measurement Facilities, Interconnector will promptly provide sealed as-built drawings (piping, instrumentation and control) and code compliance documentation to Atmos.

B. **Atmos' Responsibilities.**

1. Atmos shall design, construct, install, own, operate, and maintain, at Interconnector's expense "Tap Facilities" consisting of a ___ inch hot tap and valve, a riser containing a riser block valve, check valve and insulating flange which will be used to denote the Division of Ownership between Atmos and Interconnector with regards to piping, telemetry/SCADA equipment and other equipment installed by both parties located at ______________________.
2. Atmos will review in a timely manner all design drawings provided by Interconnector for Atmos' review in accordance with the provisions of this Agreement.

C. **General Items.**

1. All of the design and construction activities of Atmos and/or Interconnector described in this Agreement will be in accordance with "Material and Construction Specifications for Facilities Constructed by non-Atmos Contractors and Third Parties" which are incorporated herein by reference and are available to Interconnector, as they may change from time to time, on ATMOS' Web Site at :

   https://www.atmosenergy.com/cs/interconnect/index.html

   by using Interconnector's special assigned ID and Password set out in Exhibit "C," which is incorporated herein by reference. In the event such specifications do not set forth details specific enough for Interconnector to carry out any of the design or construction activities described in this Agreement, Interconnector will obtain a written clarification or exception from the applicable division's Atmos Technical Services Department before taking action. All ID's and Passwords are valid for limited periods of time and ATMOS will provide a new ID and Password upon email request as provided in Exhibit "C."
2. Due to the accelerated time schedule for the installation of the Measurement Facilities, Atmos and Interconnector both recognize that certain specified types of equipment may not be available during the initial installation of the Facilities. If a temporary substitution of equipment for the measuring station is desired by Interconnector during the initial construction of the Measurement Facilities, then Interconnector will notify the Atmos Technical Services Department of the nature of the temporary substitution and will obtain Atmos' written permission for an approved substitution. As soon as practicable thereafter the Measurement Facilities' in-service date, Interconnector will advise Atmos when the originally specified equipment is available and will

coordinate activities with Atmos so that the temporary equipment may be removed and the originally specified equipment may be installed. All costs associated with the change-out of said equipment will be borne solely by Interconnector. Ownership of the temporary equipment will remain with the Party supplying such equipment.

3. Notwithstanding any provision of this Agreement, or any other agreement between the Parties, to the contrary, no compressor shall be physically located within 100 feet of the Measurement Facilities. Applicable pulsation attenuation devices will be required if the Measurement Facilities are connected, directly or indirectly, to a compressor by less than 1000 feet of pipe. Requirements for pulsation attenuation devices for direct or indirect connections of the Measurement Facilities to a compressor by more than 1000 feet of pipe will be evaluated by the applicable division's Atmos Technical Services Department. Furthermore, in the event that vibration or noise originating from the Measurement Facilities, any upstream Interconnector's equipment, or any third-party source results in measurement inaccuracy, or additional gas quality monitoring, or the range of control or measurement is insufficient for accurate control or measurement, then Interconnector agrees to remedy such issue to Atmos' reasonable satisfaction at the sole cost and expense of the Interconnector. Notwithstanding anything herein to the contrary, no upstream or downstream facilities (including, but not limited to, compression, dehydration, separation, pigging, processing and/or treating) shall be located within 100 feet of the Measurement Facilities without the written consent of Atmos.

II. OWNERSHIP AND OPERATION OF THE MEASUREMENT FACILITIES

A. **Interconnector's Responsibilities.**

1. Upon completion of the construction and installation of the Measurement Facilities and Tap Facilities, Interconnector will own the Measurement Facilities, including any separating and over-pressure protection equipment installed by Interconnector.
2. Interconnector will own and operate all piping and equipment upstream of the Measurement Facilities.
3. Interconnector will be responsible for acquiring all operating, regulatory, and environmental permits in its name that are necessary for the construction, operation, and maintenance of the Measurement Facilities.

B. **Atmos' Responsibilities.**

1. Upon completion of the construction and installation of the Measurement Facilities and Tap Facilities, Atmos shall own the Tap Facilities. Atmos shall also operate and maintain, at Interconnector's expense, the Measurement Facilities.
2. Atmos will test, calibrate, and commission the Measurement Facilities.
3. ATMOS will be solely responsible for all daily operational activities performed in connection with the Tap Facilities and Measurement Facilities, including, but not limited to, operation, testing, calibration, adjusting and maintenance necessary for the utilization of the Tap Facilities, the Measurement Facilities, and telemetry associated therewith.

III. PAYMENT

A. **Advance Payment.**

1. Upon execution of this Agreement, Interconnector shall pay Atmos ____________________ ($_______) (the "Advance Payment") representing the estimated cost for Atmos' installation of the Tap Facilities, Atmos' review of the design drawings and Atmos' expenses, including, but not limited to, inspection expenses, related to the Measurement Facilities' construction, start-up and commissioning.
2. The estimated cost for construction and installation of the Tap Facilities and other Atmos costs shall include, but not be limited to, the cost of material, supplies, labor (Atmos and contractor), vehicles, gas loss, tax gross-up, interest carrying charges (CIAC gross-up), franchise fees, and overhead.

B. **Actual Cost.**

1. After all costs have been determined, Atmos shall submit to Interconnector a final invoice setting forth the actual costs incurred by Atmos (the "Actual Cost"). If the Actual Cost is less than the Advance Payment, Atmos shall refund the difference to Interconnector together with the final invoice. If the Actual cost is greater than the Advance Payment, Interconnector shall pay Atmos the difference within thirty (30) days of Interconnector's receipt of the final invoice.
2. Actual Cost shall include, but not be limited to, the cost of material, supplies, labor (Atmos and contractor), vehicles, gas loss, tax gross-up, interest carrying charges (CIAC gross-up), franchise fees, and overhead.

C. **Monthly Routine Maintenance Payment.**

1. For the performance of Routine Maintenance, as defined in Article VI, Section A below, Atmos shall charge Interconnector an estimated monthly fee of $___325_____. The monthly fee may be adjusted annually, upward or downward.

D. **Terms.**

1. If the amount of any invoice is not paid within 30 days, interest on all unpaid amounts will accrue at the rate of 1½% per month, or the highest rate allowed by law, whichever is less, from the date such amount is due Atmos; provided, however, no interest will accrue on unpaid amounts when failure to make payment is the result of a bona fide dispute between the Parties regarding such amounts (and Interconnector timely pays all amounts not in dispute), unless and until it is ultimately determined that Interconnector owes such disputed amounts, whereupon Interconnector will pay Atmos that amount, plus interest computed back to the original payment due date, immediately upon such determination.

2. If Interconnector fails to pay invoices for service within thirty (30) days from the invoice date or otherwise defaults under this Agreement, Atmos may suspend service and deliveries of gas and such suspension will not prevent enforcement by Atmos of any of its legal rights
3. It is further agreed that upon the event that Interconnector fails to pay Atmos any of the monies described in this Agreement within thirty (30) days of the date of Atmos' invoice and the collection of any such amounts is placed in the hands of an attorney for collection, or suit is brought on the same, or same is collected through bankruptcy or probate proceedings, then Interconnector additionally agrees to pay all of Atmos' court costs and attorney's fees, which shall be added to the amounts due to Atmos hereunder.
4. In addition, notwithstanding any other provision in this Agreement, or any other agreement between the Parties to the contrary, in the event that Interconnector fails to pay Atmos any of the monies due to Atmos pursuant to this Agreement within thirty (30) days of the date of Atmos' invoice therefore, in addition to any other rights or remedies available to Atmos, Atmos will have the right to suspend or terminate all performance under this Agreement as hereinafter defined, and suspend or terminate all receipt and/or delivery of gas for or on behalf of Interconnector through the gas facilities constructed under this Agreement until such sums are paid to Atmos.
5. Each Party will have the right at all reasonable times to examine the records of the other Party, or its agent/designee if any, to the extent necessary to verify the accuracy of any statement, charge, computation or demand made under or pursuant to any of the provisions in this Agreement. If any such examination reveals any inaccuracy in a statement, the necessary adjustments to such statement will be made; provided, however, no adjustments for any statement will be made for any inaccuracy claimed unless written notice of such claim for adjustment is furnished to the other Party within six (6) months from the rendition of the statement for which such adjustment is requested.

IV. NOTICES

All notices, requests, demands, statements and payments provided for in this Agreement must be given in writing directed to the Party to whom given, and mailed to or delivered at such Party's address set forth below, and will be deemed properly and sufficiently given when: (i) delivered in person with receipt acknowledged in writing by the receiving Party; (ii) sent by registered or certified mail, return receipt requested, to the address specified below; (iii) received at the electronic mail address, if any, specified below; or (iv) sent by telephonic document transfer to the fax number, if any, specified below:

"Interconnector"

(Notices) (Invoices)

____

____

____

Attention: Contract Administration
Fax: __________
E-mail - ____________

____

____

____

Attention: Accounting Department
Fax: __________
E-mail - ____________

"Atmos"

(Notices)
Atmos Energy
____
____
Attn: ______________
Fax: ________________
E-mail – ________________________

V. LAND RIGHTS

1. Interconnector will procure any easement, lease or other property right for the location of the Measurement Facilities , along with those Tap Facilities not to be located on an existing Atmos easement, lease, or other property right, as well as an all-weather road providing access for Atmos to the Tap Facilities and the Measurement Facilities. Any easement, lease, or other property right that is acquired by Interconnector for the installation, operation, maintenance, and replacement of Tap Facilities, shall be assigned to Atmos including the surface easement or surface lease and right of ingress or egress to Atmos, its assign, or its successors prior to the Tap Facilities' in-service date. Should the contract be terminated or the Interconnector abandons its facilities or removes them, Atmos shall continue to have the right to have its facilities in place and Interconnector shall wholly assign its easement or surface lease to Atmos.
2. Prior to negotiating or procuring any easement, lease, or other property right (the "Property Rights") associated with any equipment to be installed, operated, or owned by Atmos hereunder, Interconnector must obtain written approval from Atmos of the format and content of the documents (including a plat of the location of the Property Rights) used to secure the Property Rights (the "Instruments"). No Instrument will deviate from Atmos' standard templates used to acquire Property Rights with regard to, but not by way of limitation,

easement width, access rights, term, multiple-line rights, or above-ground rights, liability and indemnification without the prior written approval of Atmos. Copies of Atmos standard templates will be provided to Interconnector upon request. Licenses or permits will not be acceptable substitutes for the Instruments, except with the prior written approval of Atmos.

3. All pipeline easements, if applicable, will be at least fifty-feet (50') wide and the measuring station site will be at least one-hundred feet (100') by one-hundred feet (100') in size, unless the Parties mutually agree in writing to smaller sizes.

VI. OPERATION AND MAINTENANCE

A. **Routine Maintenance**

1. Atmos shall perform all of its obligations set forth above. Interconnector will be responsible for all costs associated with the maintenance, repair and replacement costs of the Tap Facilities, telemetry and Measurement Facilities associated therewith.
2. All operations will be performed in accordance with Atmos' Inspection, Operation and Maintenance Manual and all of the personnel performing covered tasks related to the tap, measuring station and telemetry associated therewith will be qualified under Atmos' Operator Qualification Program.
3. Any individual maintenance, repair(s) or replacement(s) costing $5,000.00 or less, and any emergency maintenance, repair(s) or replacement(s) may be made by Atmos within its discretion without approval by Interconnector.
4. If Atmos determines that any necessary maintenance, repair or replacement of equipment, other than an emergency maintenance, repair or replacement, will exceed $5,000.00, then Atmos will seek to obtain written approval from Interconnector prior to making such maintenance, repair or replacement.
5. In the event Interconnector does not provide Atmos with its timely approval of any repair or replacement of equipment costing in excess of $5,000.00 deemed necessary by Atmos, in its own reasonable discretion, Atmos may, by notice to Interconnector, suspend the receipt of gas from Interconnector through the Tap Facilities until the Parties mutually agree upon a repair, replacement or other course of action.
6. After Atmos performs any maintenance, repair or replacement of equipment pursuant to the terms of this Article VI, Atmos will forward to Interconnector a statement setting forth the total costs attributable to such maintenance, repair or replacement, and payment will be made by Interconnector to Atmos as provided in Article III.
7. If additional telemetry or telecommunication links must be installed to: (a) establish or maintain safe, prudent or economic operating conditions, or (b) accurately monitor the flow of gas to Atmos at the Tap Facilities, in Atmos sole reasonable opinion, Atmos will install such facilities and Interconnector will reimburse Atmos for the actual cost incurred.
8. If additional equipment is required to ensure consistent delivery of gas meeting Atmos' gas quality specifications as stated in Exhibit "D", Atmos may require Interconnector to purchase and install promptly, at

Interconnector's sole cost and expense, additional equipment as may be necessary to meet the gas quality specifications.

9. If, in Atmos' sole opinion: (a) the flow turndown or range on the meter installed at the measuring station is insufficient for accurate measurement on a day-to-day or an hour-to-hour basis; (b) the flow turndown or range on the regulator(s) or control valve(s) installed at the measuring station is insufficient for stable and accurate flow or pressure control; or (c) the existing monitoring and shut-in equipment is not adequate and that additional monitoring equipment and/or automatic shutdown equipment are necessary at the measuring station, Atmos may require Interconnector to purchase and install promptly, at Interconnector's sole cost and expense, additional equipment that meets Atmos' standards for measurement, stability, and control at the measuring station.
10. If, in Atmos' sole opinion, pulsation originating from a compressor, or associated facilities, upstream of the measuring station is responsible for either an intermittent or continuous measurement inaccuracy at the measuring station, Interconnector agrees to remedy such pulsation to Atmos' reasonable satisfaction at Interconnector's sole expense
11. Interconnector will, at the request of Atmos, assign such permits and regulatory and/or court approvals to Atmos to the extent they apply to facilities or equipment owned by Atmos during or after termination of this Agreement.
12. If after notification to Interconnector by Atmos regarding failure to comply with any of the terms and conditions of this Agreement, Atmos shall have the right to cease taking gas through the Measuring Facilities. Atmos reserves the right to cease taking gas immediately without prior notification if at any time the gas fails to meet the required gas quality specifications. Atmos shall have the right to cease taking gas immediately if at any time the warranty of ownership of such gas is contested.

VII. MISCELLANEOUS

1. As between the Parties, Atmos will act as, and be deemed to be, an independent contractor with respect to the installation of any equipment by Atmos and any other act or omission related to this Agreement. Atmos will have the sole right to control and directly supervise the method, manner and details of the installation of such facilities and Atmos may, in its sole discretion, employ or use third parties, including, without limitation, contractors, subcontractors or materials men, to install all or any part of such facilities.
2. As between the Parties, Interconnector will act as, and be deemed to be, an independent contractor with respect to the installation of any equipment by it and any other act or omission related to this Agreement. Interconnector will have the sole right to control and directly supervise the method, manner and details of the installation of such facilities and Interconnector may, in its sole discretion, employ or use third parties, including, without limitation, contractors, subcontractors or materials men, to install all or any part of such facilities.
3. A waiver by either Party of any breach of this Agreement, or the failure of either Party to enforce any provision of this Agreement, will not in any way affect, limit or waive that Party's right to thereafter enforce and compel strict compliance with the same or other provisions of this Agreement.

4. In the event either Party is rendered unable, wholly or in part, by force majeure to carry out its obligations under this Agreement, except the obligation to pay monies due hereunder, it is agreed that, on such Party's giving notice concisely describing the cause of such force majeure, in writing or by fax, email, electronic transfer or telecopy, to the other Party within a reasonable time after the occurrence of the cause relied on, the obligations of the Party giving such notice, to the extent they are affected by such force majeure, will be suspended during the continuance of any inability so caused, but for no longer period, and such cause will, so far as possible, be remedied with all reasonable dispatch. The inability, or the failure of a Party perform a duty or obligation under this Agreement due to force majeure may not be the basis of claims for damages sustained by either Party or for breach of contract.
   a. The term "force majeure" as employed herein shall mean, but not by way of limitation, acts of God, the elements, strikes, lockouts or other labor or industrial disturbances, acts of the public enemy, arrests, wars, blockades, insurrections, riots, civil disturbances, criminal act, vandalism, terrorism or a terrorist act or acts and epidemics; landslides, lightning, earthquakes, fires, hurricanes, storms, floods and washouts; arrests, orders, directives, restraints and requirements, priority limitation or restraining orders of any government or governmental agencies, whether federal, state, civil or military; accident or obstructions involving a pipeline, machinery or lines of pipe; repairs or outages (shutdowns) of power plant equipment or lines of pipe for inspection, maintenance, change or repair; freezing of lines of pipe; tests, maintenance, or repairs to machinery, equipment, lines of pipe or other facilities; freezing of equipment, lines of pipe or other facilities; inability to obtain, or unavoidable delay in obtaining, material, equipment, rights-of-way or permits; and any other causes, whether of the kind herein enumerated or otherwise, not reasonably within the control of the Party claiming suspension. Further, it is agreed that that the handling of litigation with third parties of any fact or issue and the settlement of strikes or lockouts will be entirely within the discretion and control of the Party involved, and that the above reasonable dispatch will not require any particular action or the settlement of strikes or lockouts by acceding to the demand of the opposing third party when such course is deemed to be inadvisable or inappropriate in the discretion of the Party involved.
5. Atmos shall have the right to curtail, interrupt or discontinue service in whole or in part on all or part of its system from time to time. This may be in order to perform repair, maintenance, replacement or miscellaneous construction on the system as necessary to maintain operational capability or comply with applicable governmental regulations or for other reasons as deemed necessary by Atmos and shall not be liable to INTERCONNECTOR in any manner due to any such curtailment, interruption or discontinuance of service. ATMOS shall exercise due diligence to schedule such activities so as to minimize interruptions or disruption of services and shall provide reasonable advance notice of same.
6. Nothing in this Agreement will create, or be construed as creating; any express or implied rights in any person or entity other than Atmos and Interconnector.
7. The term of this Agreement will be for a primary term of __ years beginning ____________ and having a termination date of ____________, and then year to year thereafter, until cancelled by either Party giving written notice at least 90 days prior to the end of the primary term or any year thereafter. Within one year after the termination of this Agreement, Interconnector will have the right, upon at least 30 days prior written notice to Atmos, to remove its measuring station, but will continue to indemnify Atmos pursuant to the

provisions of this Agreement for Interconnector's activities prior to and during such removal. Notwithstanding any provision of this Agreement to the contrary, all obligations and duties of Atmos under this Agreement will be suspended until and commence after: (a) Atmos receives two (2) originals of the form of this Agreement; (b) Atmos receives the Advance Payment from Seller described in Article III; and (c) Atmos executes the two (2) originals of the form of this Agreement that have been fully executed by INTERCONNECTOR

8. THIS AGREEMENT WILL BE CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, NOTWITHSTANDING ANY CONFLICT OF LAW PRINCIPLES THAT MIGHT REQUIRE THE APPLICATION OF THE LAWS OF ANOTHER JURISDICTION. This Agreement is made, and is performable, in _______ County (Parish), ______. This Agreement is subject to all applicable state and federal laws, and all orders, directives, rules and regulations of any governmental body, official or agency having jurisdiction.
9. The Parties agree that the rates and terms of this Agreement have been reached through arms length negotiations and that neither Party had an unfair advantage during the negotiations thereof.
10. EXCEPT IN REGARD TO DAMAGES TO THIRD PARTIES FOR WHICH ONE PARTY MAY BE INDEMNIFIED BY THE OTHER PARTY, IN THE EVENT ONE PARTY IS LIABLE TO THE OTHER PARTY DUE TO ANYTHING RELATED TO THIS AGREEMENT, WHETHER ARISING IN CONTRACT, EQUITY OR TORT (INCLUDING WITHOUT LIMITATION ANY CLAIM FOR NEGLIGENCE OR STRICT LIABILITY,), THE AMOUNT OF DAMAGES RECOVERABLE WILL NOT INCLUDE ANY AMOUNT FOR SPECIAL, CONTINUING, EXEMPLARY, PRESUMPTIVE, INCIDENTAL, INDIRECT OR CONSEQUENTIAL DAMAGES (WHICH TERMS SHALL INCLUDE LOST PROFITS, LOST INCOME AND LOST SAVINGS), OR FOR ANY AMOUNT RELATED TO CLAIMS AGAINST THE ONE PARTY BY ANY THIRD PARTY OR PARTIES, EXCEPT THOSE DAMAGES TO A THIRD PARTY OR PARTIES FOR WHICH THE ONE PARTY MAY BE INDEMNIFIED BY THE OTHER PARTY, AS PROVIDED FOR IN THIS AGREEMENT.
11. This Agreement will be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns; provided, however, that Interconnector may not assign any of its rights or obligations under this Agreement without the express, written consent of ATMOS, which consent will not be unreasonably withheld. No assignment will relieve the assigning Party of any of its duties or obligations under this Agreement.
12. Except as required by law, regulation, or order of government authority (including, but not limited to, any filings required by the Securities and Exchange Commission in the normal conduct of either party's business), order of a court or arbitrator(s), or upon written consent of the other party, each party and its respective agents, employees, affiliates, officers, directors, and attorneys, auditors and other representatives shall keep and maintain this agreement and the terms or provisions thereof in strict confidence, and shall not transmit, reveal, disclose or otherwise communicate any of the terms and provisions of this agreement to any person without first obtaining the consent of the other party, which consent shall not be unreasonably withheld. This section shall not apply to any required reporting by Atmos or Interconnector pursuant to orders or regulations of any regulatory authority with proper jurisdiction.
13. This Agreement constitutes the entire agreement between the Parties covering the subject matter hereof, and there are no agreements, modifications, conditions or understandings, written or oral, express or implied, pertaining to the subject matter hereof that are not contained herein.

14. Each and every term or obligation in this Agreement is separate and independent from every other term or obligation, and the breach of any term or obligation will in no way or manner discharge or relieve the performance of any other term or obligation. Each and all of the rights and remedies given to either Party by this Agreement, or by law or in equity, are cumulative, and the exercise of any such right or remedy by either Party will not impair such Party's right to exercise any other right or remedy available to such Party, under this Agreement, or by law or in equity.
15. If any provision of this Agreement is held invalid by any court or regulatory authority, then such provision will be deemed severable and the remainder of this Agreement will continue in full force and effect.
16. Notwithstanding any other provision of this Agreement or any other agreement of the Parties, any and all electronic versions of this Agreement and any amendments thereto shall be considered to be drafts and the only effective version of this Agreement or any amendment hereto shall be a written, hard copy executed by both Parties.
17. This Agreement is not an agreement to transport, buy or sell gas. Any transportation, sale or purchase of gas through the Measurement Facilities described in, upgraded, installed or constructed under this Agreement will be performed under the terms and conditions of one or more separate written agreements. No sale, purchase, receipt, delivery or transportation of gas will be performed under the terms of this Agreement. Further, the Parties agree that this Agreement does not waive any gas quality specifications in any agreement.

VIII. INDEMNITY

Notwithstanding any other provision in this Agreement, each Party ("Indemnifying Party") agrees to protect, defend, indemnify and hold the other Party ("Indemnified Party"), its directors, officers, employees, attorneys-in-fact, agents, partners and affiliated companies, free and harmless from and against any and all losses, claims, liens, demands, and causes of action of every kind and character, including, but not limited to, the amounts of judgments, penalties, interest, court costs, investigation expenses and costs and attorney's fees incurred by the Indemnified Party, its directors, officers, employees, attorneys-in-fact, agents, partners and affiliated companies, in defense of same arising in favor of any governmental agencies, third parties, contractors or subcontractors, on account of taxes claims, liens, debts, personal injuries, death or damages to property, and all other claims or demands of every character occurring or in any way incident to, in connection with, or arising out of the Indemnifying Party's or its contractor's or subcontractor's negligence, gross negligence or willful misconduct solely related to activities performed under this agreement, except to the extent that any such liability, loss, claim, damage, cost or expense is caused by the actions, omissions, negligence, gross negligence, willful misconduct, fault or breach of the other Party. This Section will survive the termination of this Agreement.

ACCEPTED AND AGREED TO THIS DAY OF , 20__.	ACCEPTED AND AGREED TO THIS DAY OF , 20__.
[Interconnector]	ATMOS ENERGY CORPORATION

By: ______________________ By: ______________________

Name: ______________________ Name: ______________________

Title: ______________________ Title: ______________________

EXHIBIT "A"

(i) a _____" orifice meter; (ii) a _____" ultrasonic meter; (iii) a control valve, with control valve panel; (iv) overpressure protection with automatic shut-in valve; (v) a check valve, (vi) an electronic flow measurement device, and appurtenances with a communication interface (collectively, the "EFM"); (vii) an ATMOS approved gas chromatograph ("GC") with appropriate shut-in capabilities; (viii) a hydrogen sulphide ("H2S") monitor(s), with an automatic shut-in valve (with the capability to shut off and prevent the flow of any gas that does not meet the Applicable Gas Quality Specifications into ATMOS' facilities), related tubing, manifolds and hand valves, that will constantly monitor all gas that flows into ATMOS' facilities, as well as electric power for the H2S monitor, instrumentation and tubing; (ix)an odorizer and appropriately sized odorant tank (together the "Odorizer"); (x) a moisture monitor with an automatic shut-in valve; (xi) a drip pot with level switch and appropriate liquids monitoring and shut-in equipment; (capable of preventing the flow of gas into ATMOS' facilities that does not meet the Applicable Gas Quality Specifications); (xii)an equipped telemetry building, and all related instrumentation and tubing not provided by ATMOS under Section 2; (xiii) oxygen monitor with automatic shut-in valve; and (xiv) electric power and telephone service for the operation of the facilities described above

EXHIBIT “B”

Drawings

3rd Party Receipt into an Atmos Distribution Line -- drawing number PD 11985 sheets 1 through 5

- Sheet 1 of 5 – Piping and Instrumentation Diagram
- Sheet 2 of 5 – Standard P & ID Legend
- Sheet 3 of 5 – Typical 2” Measuring Station Lot Layout
- Sheet 4 of 5 - Plans, Sections and Details
- Sheet 5 of 5 –2” Regulator and Meter Spools

EXHIBIT "C"

To that Certain Interconnect Agreement dated ____________, 2008, BETWEEN Atmos ____________, a division of Atmos Energy Corporation and ___________________

____________'s USER ID and PASSWORD to ATMOS' INTERNET WEB SITE

Internet Web Address:

https://www.atmosenergy.com/cs/interconnect/index.html

User IED: __________________ **
Password: _________________ **

**** The above ID and Password are valid until ________________.**

EXHIBIT "D"

Gas Quality Specifications

The gas to be delivered hereunder by Seller at the Point of Delivery shall comply at all times with the following quality specifications:

Heating Value: The gas shall have a total (gross) heating value of not less than nine hundred fifty (950) Btu's per cubic foot and not more than one thousand one hundred (1,100) Btu's per cubic foot, each being expressed on a "dry basis" at 14.65 psi.

Hydrogen Sulfide: The hydrogen sulfide content shall not exceed one-quarter (1/4) grain per one hundred (100) cubic feet of gas.

Mercaptans: The mercaptan sulphur content shall not exceed one (1) grain per one hundred (100) cubic feet of gas.

Total Sulphur: The total sulphur content, including hydrogen sulfide and mercaptans, shall not exceed twenty (20) grains per one hundred (100) cubic feet of gas.

Total Non-Hydrocarbon Gas: The total of all non-hydrocarbon gases shall not exceed 4.0%.

Carbon Dioxide: The carbon dioxide content shall not exceed three percent (3%) by volume.

Oxygen: The oxygen content shall not exceed one-tenth of one percent (0.1 of 1%) by volume, and Seller shall make every reasonable effort to maintain the gas totally free from oxygen.

Nitrogen & Helium: The combined nitrogen and helium content shall not exceed three percent (3%) by volume.

Other: The gas shall contain no carbon monoxide, halogens or unsaturated hydrocarbons and no more than 0.04% of hydrogen.

Liquids: The gas shall be free from water and hydrocarbons in liquid form at the temperature and pressure at which the gas is delivered and, further provided, the gas shall not contain any hydrocarbons which may condense to liquid state under normal pipeline operating conditions and shall in no event contain water vapor in excess of seven (7) pounds per one million (1,000,000) cubic feet of gas.

Freedom From Objectionable Matter: The gas shall be commercially free from PCB's, objectionable odors, sand, dust, gums or other solid, liquid or gaseous matters including any additives or diluents which may be injurious to conventional pipeline materials or which may otherwise interfere with the transmission, distribution or commercial utilization of said gas.

Temperature: The gas shall not be at a temperature of less than forty degrees (40^{o}) Fahrenheit nor more than one hundred twenty degrees (120^{o}) Fahrenheit.

Negative Pressure: The gas shall not be produced at or encounter before delivery a pressure of less than atmospheric pressure.

Heavier Hydrocarbons: The heavier hydrocarbon content shall not exceed 0.05 gallons/Mcf of C_6 and heavier hydrocarbons.

Hydrocarbons Dewpoint: The hydrocarbon dewpoint shall not exceed 5^{o} F at delivery pressures or lower. Note that maximum hydrocarbon dew point may be lower if downstream delivery contracts include lower maximum hydrocarbon dew point requirements.

Bacteria: The gas shall be free of bacteria.

Radon Gas: The Gamma radiation in the gas shall not exceed 50 microroentgens/hr.

Lead: The Lead 210 content shall not exceed 30 PCi/gram.

Other Heavy Metals: All other heavy metals shall not exceed 150 Pi/gram. Arsenic, Mercury, Silver, Barium, Cadmium, Chromium and Selenium shall be less than 5 mg/Liter.

All gas shall be free from objectionable odors, PCB's, dust, hydrocarbon liquids, water or other solid or liquid matters, any microbiological organism, gum, gum-causing constituents, active bacteria or bacterial agent capable of contributing to or causing corrosion and/or operational and/or other problems. Microbiological organisms, bacteria or bacterial agents include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (APB).

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE II. Schedule of Service Fees

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

SCHEDULE II - SCHEDULE OF SERVICE FEES

Applicability: Service Fees may be collected by Company from its Customers under the circumstances and in the amount hereinafter set forth:

A. METER READING FEE

In the event the Customer does not furnish a required meter reading for two (2) consecutive billing periods, the Company may read the Meter and the Company will require a Meter Reading fee of $5.00.

B. WORTHLESS CHECK CHARGE

The Company may require for each Customer check returned for insufficient funds a Worthless Check Charge not to exceed the amount provided by K. S. A. 21-3707 or as thereinafter amended ($30.00).

C. INSUFFICIENT FUNDS CHARGE (ELECTRONIC TRANSACTION)

The Company may require for each Customer's electronic transaction reversed due to a lack of funds available an Insufficient Funds Charge not to exceed $30.00.

D. COLLECTION CHARGE

When collection is made at the Customer's premises to avoid disconnection of Gas Service or Gas Service is discontinued because of non-payment of a Gas Service bill, the Company will require a Collection Charge of $8.00.

E. DISCONNECTION CHARGE

When Gas Service is disconnected for any of the reasons stated in Schedule I, Section 5, A. 1. of the Company Rules and Regulations, except when requested by the Customer, the Company will require a Disconnection Charge of $15.00 During Normal Business Hours/$20.00 Other Than Normal Business Hours, but not both a collection charge and a disconnection charge.

F. INITIATE OR RECONNECT CHARGESDURING NORMAL BUSINESS HOURS

When Gas Service is initiated or reconnected, the Company will require a charge of $20.00 During Normal Business Hours/$25.00 Other Than Normal Business Hours.

Issued:	January (Month)	26, (Day)	2012 (Year)
Effective:	Upon Commission Approval (Month)	(Day)	(Year)
By:	(Signature of Officer)		VP-Reg & Public Affairs (Title)

G. INITIATE OR RECONNECT CHARGES-MULTIPLE UNIT BUILDING OR MULTI-FAMILY DWELLING UNITS

When Gas Service is reconnected, except when disconnected pursuant to Customer's request, to multiple unit buildings or multi-family dwelling units served by one Meter, a reconnection charge shall be made which shall be the greater of a) $20.00 During Normal Business Hours/$25.00 Other Than Normal Business hours (b) $4.00 During Normal Business Hours/$5.00 Other Than Normal Business Hours, per building or family dwelling unit.

H. METER TEST CHARGES

The Company, upon written request by a Customer, shall test the accuracy of the Meter used by the Customer provided the Meter has not been tested by the Company within one year previous to such test. The Customer will be required by the Company to make an advance deposit to cover the cost of the Meter test, which shall be in the following amounts:

1. Diaphragm displacement meters having a rated capacity of 300 cubic feet per hour or less $10.00.

2. Diaphragm displacement meters have a rated capacity of exceeding 300 cubic feet per hour and not exceeding 1,000 cubic feet per hour $37.50.

3. Diaphragm displacement meters having a rated capacity exceeding 1,000 cubic feet per hour $50.00.

4. Rotary displacement meters-No charge.

5. Orifice meters-No charge.

I. TEMPORARY SERVICE FEE

Upon request of a Customer, the Company will provide a temporary service and a minimum charge of not less than $25.00 shall be paid for such temporary service

J. CREDIT/DEBIT/ATM CARDS

The Authorized Pay Agent may charge the customer an additional fee of $3.95 per $500 for the use of credit/debit/ATM cards.

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE II. Schedule of Service Fees

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

K. TRIP CHARGE

When Company personnel and equipment have been utilized for non-emergency type services, a $30.00 Trip Charge will be required.

L. ELECTRONIC MEASUREMENT TRIP CHARGE

When Company personnel and equipment have been utilized in responding to electronic measurement services, a $30.00 Trip Charge will be required.

Issued:	January	26,	2012
	(Month)	(Day)	(Year)
Effective:	Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)		(Title)

SECTION 1 – GENERAL

A. COUNTIES/COMMUNITIES SERVED:

County	City
Allen	Elsmore
Allen	Savonburg
Barber	Hazelton
Bourbon	Fort Scott
Bourbon	Fulton
Bourbon	Hammond
Bourbon	Redfield
Chase	Cottonwood Falls
Chase	Strong City
Chautauqua	Cedar Vale
Chautauqua	Chautauqua
Chautauqua	Elgin
Chautauqua	Hewins
Chautauqua	Niotaze
Chautauqua	Peru
Chautauqua	Sedan
Coffey	Burlington
Coffey	LeRoy
Coffey	New Strawn
Crawford	McCune
Dickinson	Herington
Douglas	Eudora
Douglas	Lawrence
Elk	Elk Falls
Elk	Grenola
Elk	Longton
Elk	Moline

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

County	City
Grant	Hickock
Grant	Ulysses
Greenwood	Eureka
Greenwood	Fall River
Greenwood	Hamilton
Greenwood	Neal
Hamilton	Kendall
Hamilton	Syracuse
Harper	Anthony
Harper	Danville
Johnson	De Soto
Johnson	Gardner
Johnson	Lenexa
Johnson	New Century
Johnson	Olathe
Johnson	Overland Park
Johnson	Shawnee
Johnson	Spring Hill
Labette	Bartlett
Labette	Chetopa
Labette	Edna
Labette	Mound Valley
Leavenworth	Basehor
Leavenworth	Easton
Leavenworth	Jarbalo
Leavenworth	Leavenworth
Leavenworth	Linwood
Linn	Mound City
Linn	Pleasanton
Linn	Prescott

Issued: January 26, 2012
(Month) (Day) (Year)

Effective: Upon Commission Approval
(Month) (Day) (Year)

By: VP-Reg & Public Affairs
(Signature of Officer) (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding
shall modify the tariff as shown hereon.

County	City
Marion	Aulne
Marion	Florence
Marion	Hillsboro
Marion	Lincolnville
Marion	Lost Springs
Marion	Marion
Marion	Marion Lake
Marion	Peabody
Marion	Pilsen
Marion	Ramona
Marion	Tampa
Miami	Hillsdale
Montgomery	Caney
Montgomery	Coffeyville
Montgomery	Dearing
Montgomery	Elk City
Montgomery	Havana
Montgomery	Independence
Montgomery	Liberty
Montgomery	Sycamore
Montgomery	Tyro
Morris	Council Grove
Morris	Delavan
Morris	White City
Morris	Wilsey
Morton	Unincorporated Irrigation
Neosho	Galesburg
Neosho	Morehead
Neosho	Stark
Neosho	Thayer

Issued: January (Month) 26, (Day) 2012 (Year)

Effective: Upon Commission Approval (Month) (Day) (Year)

By: (Signature of Officer) VP-Reg & Public Affairs (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

County	City
Ness	Bazine
Ness	Ness City
Rush	Alexander
Rush	McCracken
Stanton	Johnson City
Stanton	Manter
Stevens	Unincorporated Irrigation
Sumner	Caldwell
Sumner	Hunnewell
Sumner	South Haven
Wilson	Altoona
Wilson	Benedict
Wilson	Buffalo
Wilson	Fredonia
Wilson	LaFontaine
Wilson	Neodesha
Woodson	Toronto
Woodson	Yates Center
Wyandotte	Bonner Springs
Wyandotte	Edwardsville
Wyandotte	Kansas City

B. COUNTIES SERVED AT WHOLESALE: NONE

C. RATES APPLICABLE TO WHOLESALE CUSTOMERS: NONE

Issued:	January	26,	2012
	(Month)	(Day)	(Year)
Effective:	Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)		(Title)

SECTION 2 – FIRM SALES SERVICE

A. Residential Sales Service (Rate Schedule 910)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to residential customers at a single location.

2. MONTHLY BILL

a. Facilities Charge: $19.00per month
b. Commodity Charge: $0.15576per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA, WNA Schedules, and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

5. 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 service, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

B. Commercial/Public Authority (General) Sales Service (Rate Schedule 915)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to commercial and public authority customers at a single location.

2. MONTHLY BILL

a. Facilities Charge: $$44.00per month

b. Commodity Charge: $0.15576per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA, WNA Schedules and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas

5. 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 service, the Company may estimate and determine the appropriate consumption of the light and charge the applicable rate under this rate schedule.

C. School Sales Service (Rate Schedule 920)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to state, county, city and private educational institutions or universities constructed before January 1, 1995 at a single location.

2. MONTHLY BILL

a. Facilities Charge: $44.00per month

b. Commodity Charge: $0.15576per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA, WNA Schedules and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

D. Industrial Sales Service (Rate Schedule 930)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to industrial customers at a single location.

2. MONTHLY BILL

a. Facilities Charge: $90.00per month

b. Commodity Charge: $0.15576per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA Schedules and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

E. Small Generator Sales Service (Rate Schedule 940)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to commercial customers, at a single location, for separately metered electric generators of less than 20 kilowatts of capacity.

2. MONTHLY BILL

a. Facilities Charge: $44.00 per month

b. Commodity Charge: $0.15576per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA Schedules.

The minimum bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

F. Irrigation Engine Sales Service (Rate Schedule 965)

1. APPLICABILITY

Available in and around the communities specified in the Section 1 A. to engine irrigation customers at a single location.

2. MONTHLY BILL

a. Facilities Charge: $60.00per month

b. Commodity Charge: $0.09600per 100 cubic feet (Ccf) plus applicable adjustments and charges provided in the Company's PGA Schedules and Customer Utilization Adjustment.

The minimum monthly bill shall be no less than the Facility Charge plus any applicable service charges.

3. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

SECTION 3 - INTERRUPTIBLE GAS SALES SERVICE

A. Large Industrial Sales Service (Rate Schedule 955)

1. APPLICABILITY

a. This rate schedule is available at the Company's option to any large volume user using at least 220,000 Ccf annually or customers using 1,000 Ccf per day during off peak periods. Customer shall have and maintain adequate standby facilities and fuel in order that gas deliveries may be curtailed in whole or in part at any time upon thirty minutes notice.

b. Those customers who were transporting gas on the Company's Rate Schedule 960 prior to September 1, 1995 will be grandfathered to this rate schedule.

c. Customers electing this service after September 1, 1995 must use at least 220,000 Ccf annually to continue service under this schedule. The Company may waive this condition if unusual circumstances exist. If the same customer uses less than 220,000 Ccf annually after the second year of service, the customer will be changed to Rate Schedule 930 or Rate Schedule 950.

2. CHARACTER OF SERVICE

a. Natural gas, with a heating value of approximately 100,000 BTU per Ccf, supplied through a single meter, at standard equipment utilization pressure, or such higher delivery pressure as approved by Company.

b. "Optional Gas" is the quantity of gas Customer agrees to purchase and Company agrees to deliver in any one day when Company has gas available and when Company's distribution system is suitable for such delivery.

c. "Firm Gas" is the daily quantity of gas delivered to a customer within that Customer's contract demand quantity, if any. Customers electing to receive firm gas under this rate schedule shall contract for a minimum of 500 Ccf per day. Customers served under Rate Schedule 950 prior to September 1, 1995 with a quantity of less than 500 Ccf shall be grandfathered. Firm gas is not subject to curtailment, except as described under the Priority of Service section of this rate schedule, and only then if all optional gas service has been curtailed first.

d. Company is also relieved of its obligation to deliver any gas under this schedule in the event of force majeure. Any curtailments which may be necessary under this rate schedule shall be made only after having given at least 30 minutes notice by telephone or otherwise unless due to reasons of force majeure.

3. INTERRUPTION AND CURTAILMENT OF OPTIONAL SERVICE:

a. Optional gas deliveries to customers served on this schedule may be interrupted or curtailed at any time such interruption or curtailment is necessary in order for Company to continue to supply the gas requirements of its other customers at such time. The Company will endeavor to notify in advance customers served on this schedule whenever a curtailment or interruption is required, and each such customer shall curtail his use of gas at the time and to the extent requested by the Company. Interruptions and curtailments may vary from time to time among customers, but shall be as equally apportioned as practicable.

b. "Unauthorized Use" is defined as the taking of any volume of optional gas by Customer during any period when the use of optional gas is curtailed in accordance with notice given by Company. Company shall bill, and Customer shall pay $2.50 per Ccf for all volumes of unauthorized use gas in addition to the rate billed under this schedule.

4. CONTRACT

a. Customer shall contract for service hereunder for a term of not less than one (1) year. Upon the expiration of any contract term, the contract shall be automatically renewed for a period of one (1) year. At any time following the first contract year, service may be terminated by either party following at least six (6) months notice to the other party.

b. A day, as used herein, shall be defined as a period of 24 consecutive hours designated by Company to coincide with applicable pipeline contract.

5. RATE

a.	Facilities Charge	$325.00	per month
b.	Commodity Charge	$0.08200	First 20,000 Ccf per month
		$0.07400	All over 20,000 Ccf per month

6. DEMAND RATE

a.	Demand Rate	The sum of the reservation costs for which the Company has contracted with Southern Star Central Gas Pipeline, Inc.,

		per Ccf of Contract Demand.
b.	Daily Demand Rate	The Demand Rate divided by 30.4 days, per Ccf per day for all gas in excess of the Contract Demand level.

a.	Demand Rate	The sum of the reservation costs for which the Company has contracted with Southern Star Central Gas Pipeline, Inc., per Ccf of Contract Demand.
b.	Daily Demand Rate	The Demand Rate divided by 30.4 days, per Ccf per day for all gas in excess of the Contract Demand level.

7. MONTHLY BILL

The minimum monthly bill applicable at single address or location shall be the sum of the Facility Charge and the Demand Charge, Daily Demand Charge and the Commodity Charge as follows:

a. The Demand Charge shall be the product of the demand level nominated by the Customer and the Demand Rate.

b. The Daily Demand Charge shall be the product of the unauthorized volumes taken by Customer when curtailed by Company under this rate schedule on each day during the billing period in excess of the demand level nominated by the Customer and the Daily Demand Rate.

c. The Commodity Charge shall be the product of all volumes delivered under this rate during the billing period and the Commodity Rate.

8. BASIS OF MEASUREMENT

Natural gas delivered shall be measured at prevailing meter pressures and the volumes thereof shall be computed at a pressure base of 14.65 pounds per square inch at a temperature of 60 degrees Fahrenheit. The Company may assume that the gas delivered obeys Boyle's Law and atmospheric pressure is 14.4 pounds per square inch and the flowing temperature of the gas in the meter is 60 degrees Fahrenheit.

9. PURCHASED GAS ADJUSTMENT

The above rate is subject to increase or decrease to reflect changes in purchased gas costs in accordance with the provisions of the Company's non-firm PGA.

10. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

B. Economic Development Sales Service (Rate Schedule 960)

1. APPLICABILITY

a. Service under this Schedule is available to customers engaged in the manufacturing process at discounted or incentive rates. Customers engaged in retailing goods and services to the public are not eligible for this service. To be eligible for service under this schedule certain conditions must be met by the customer. Existing customers served under another rate schedule to be eligible for service under this rate schedule must contract for sufficient natural gas demand to produce an increase in consumption of 135,000 Ccf annually. New customers served under this rate schedule to be eligible must contract for at least 270,000 Ccf annually. Customers served under this Rate Schedule must demonstrate increased employment.

b. This Schedule is intended to allow the Company to offer incentive or discount type rates designed to enhance the Company's system utilization while encouraging industrial development within the Company's service areas.

2. SPECIAL TERMS AND CONDITIONS

a. A contract shall be executed by the customer for a minimum of 4 years. The contract shall specify the customer's natural gas requirements.

b. To receive service under this rate schedule, the customer's written application to the Company shall include sufficient information to permit the Company to determine the customer's eligibility.

c. Qualifying consumption shall result from an increase in business activity and not merely from the resumption of normal operations following a period of abnormal operating conditions. If in the Company's opinion an abnormal operating period has occurred as a result of strike, equipment failure, or any other abnormal condition during the twelve (12) month period prior to the date of the application by the customer for service under this rate schedule, the Company shall adjust the customer's consumption to eliminate any abnormal condition. The Company through use of historical data shall determine "Base Load" for existing customers. Volumes used in excess of "Base Load" shall be considered "Qualifying Consumption" and eligible under this Schedule. Loads which are or have been served by the Company during all or part of the twelve (12) month period prior to service under this rate schedule, and which are relocated to another metering point within the Company's service area, shall not qualify for this rate schedule.

d. The existing facilities of the Company must be adequate in the judgment of the Company to supply the new or expanded natural gas requirements. If construction of new or expanded local facilities by the Company is required, the customer may be required to make a Contribution in Aid of Construction for the installed cost of such facilities. The Company will evaluate the customer's request for service and determine the necessity of a contribution for construction of facilities based on the Extension of Service provisions of the General Terms and Conditions of the Company's filed tariff. The Company shall review the Customer's consumption each year to determine whether the Customer has fulfilled their projected usage requirement to remain eligible for service under this rate schedule.

3. FACILITY CHARGE

a. A monthly facility charge equal to the otherwise applicable companion rate schedule is payable regardless of the usage of gas.

b. The following adjustment factors will be applied to the "Qualifying Consumption" and based on the rate schedule which would apply to the Customer absent this rate schedule. The Customer may elect to begin service under this Schedule on the 1st month or 13th month of service with the Company

Billing Months In Contract Year	Adjustment Factor
1st Through 12th	75%
13th Through 24th	75%
25th Through 36th	75%
37th Through 48th	75%
After 48 Months	100%

4. MINIMUM MONTHLY BILL

The minimum monthly bill shall be the monthly Facility Charge plus the Monthly Demand Charge, if any.

5. PURCHASED GAS ADJUSTMENT

The above rate is subject to increase or decrease to reflect changes in purchased gas costs in accordance with the provisions of the Company's firm or non-firm PGA, whichever is the companion to the otherwise applicable sales rate.

6. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

SECTION 4 - TRANSPORTATION SERVICE

A. General Service Firm Transportation Service (Rate Schedule FT900)

1. AVAILABILITY

See Schedule I, Section 12 A – Transportation Services

2. MONTHLY BILL

Companion Sales Schedule	Facility Charge	Commodity Charge
915, 920	$90.00	$0.15576/ ccf + take-or-pay costs set for on Sheet 1 of 1
930	$90.00	$0.15576/ ccf + take-or-pay costs set for on Sheet 1 of 1

The minimum monthly bill shall be the facility charge and the demand charge, if any.

3. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the applicable companion sales rate schedule conditions and to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Constructions of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IV: Sales and Transportation Rates

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

B. Interruptible Transportation Service (Rate Schedule IT900)

1. AVAILABILITY

See Schedule I, Section 12 A – Transportation Services

2. MONTHLY BILL

Companion Sales Schedule	Facility Charge	Commodity Charge
955	$325.00	$0.08200 / ccf, first 20,000 $0.07400 / ccf, greater than 20,000 + take-or-pay costs set for on Sheet 1 of 1

The minimum monthly bill shall be the facility charge and the demand charge, if any.

3. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the applicable companion sales rate schedule conditions and to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Constructions of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

Issued:	January (Month)	26, (Day)	2012 (Year)
Effective:	Upon Commission Approval (Month)	(Day)	(Year)
By:	(Signature of Officer)		VP-Reg & Public Affairs (Title)

C. Interruptible Negotiated Transportation Service (Rate Schedule IT-NEG)

1. AVAILABILITY

a. Gas service under this rate schedule is available to those customers having alternate fuel capability at the Company's discretion. This rate schedule is designed to permit the Company to meet alternate fuel and/or gas to gas competition. Service under this rate schedule shall be fully optional and subject to curtailment prior to optional customers.

b. The intent of this rate schedule is to provide the Company flexibility to provide service at negotiated rates when the otherwise applicable tariff rates are noncompetitive. The Company will make every effort to maximize recovery of base margins and fixed components of the purchased gas adjustment.

c. The Company's decision to enter into a discounted service agreement and the amount of the discount will be subject to review by the Commission at the Company's next rate case for the purpose of setting future rates. Discounted service agreements shall be granted only to retain or obtain a Customer who has a credible competitive alternative available. The amount of the discount from the maximum approved tariff rate shall be the least necessary to retain or obtain the customer.

d. In situations where the discounted service agreement involves a company affiliate, Company shall file with the Commission a copy of the agreement with all supporting documentation and worksheets, within 10 days of the date of the agreement.

2. MONTHLY BILL

a.	Facilities Charge	$325.000 per month
b.	Commodity Charge	

The rates charged under this rate schedule shall be negotiated on a per customer basis. The Company may require supporting documents from the end-user certifying that the cost of available alternate supply is less than the otherwise applicable tariff rate. The maximum charge shall not exceed the sales rate schedule under which the customer would otherwise be charged. In no event shall the price negotiated be less than the incremental costs of serving the Customer plus $0.001/Ccf.

The minimum monthly bill shall be the monthly facility charge.

3. UNAUTHORIZED GAS

"Unauthorized Use" is defined as the taking of any volume of optional gas by Customer during any period when the use of optional gas is curtailed in accordance with notice given by Company. Company shall bill, and Customer shall pay $2.50 per Ccf for all volumes of unauthorized use gas in addition to the rate billed under this schedule.

4. OTHER TERMS AND CONDITIONS

Service hereunder is subject to the Company's General Terms and Conditions for Service including Curtailment of Service, Service Fee Schedule and Schedule of Customer Advances for Construction of Mains and Company Service Lines as approved by the State Corporation Commission of the State of Kansas.

SCHEDULE V – PURCHASED GAS ADJUSTMENT (PGA)

SECTION 1 - PURCHASED GAS COST ADJUSTMENT PROCEDURE

A. RATE SCHEDULES COVERED

All of the Company's sales rate schedules shall be subject to a purchased gas cost adjustment:

Description	Combined Kansas Rate Division and Southwest Kansas Rate Division
Firm Sales Service including: Residential, Commercial, Public Authority, School, Irrigation Engine, Agricultural Service, and Small Industrial.	910, 915, 920, 930, 940, 960, 965
Interruptible Sales Service including: School, Small Industrial, Large Industrial, and Economic Development.	955, 960

B. COMPUTATION FORMULA

1. The Company's rates for gas service are subject to adjustment for change in the average cost of gas from all sources of supply purchased. At the end of the twelve-month period ending August, the Company will project the average cost of gas for the twelve months ending August 31 of the following year. If at any time during this twelve month period the Company experiences a change or changes in supplier rates or in sources of supply, the cumulative effect of which change or changes is to produce an increase or decrease in the new projected effective rate for purchased gas from all suppliers of at least $.010 per Ccf, then an adjusted average rate shall be determined. The annual cost of gas projection and any revised projections throughout the year will be computed using the following formula:

$$\frac{P + E + S + C}{V} = \text{Adjustment}$$

Where:

P = The estimated total dollar cost of purchased gas to be sold calculated by summing the products of the most recent unit cost of purchased gas from each supplier and the estimated unit purchases from each supplier for the twelve month period ending August 31. In the event that changes in the rates paid for purchased gas will take place within the current twelve month period ending August 31, as specified by contract provisions currently in effect, the estimated average unit cost of purchased gas from each supplier for the current twelve month period ending August 31, may be used in the calculation in place of the most recent unit cost.

E = Estimated net cost (positive or negative) arising from exchange gas transactions that are expected to occur during the twelve month period ending August 31 (Account 806), not including storage gas transactions.

S = Estimated cost of stored gas to be withdrawn from storage (Account 808) and sold.

V = The estimated sales volume in Ccf for the twelve month period ending August 31. (If the actual sales volume reflects a line loss factor greater than the limit value, restatement of sales volume, based on the limit value for line loss, shall be required.)

C = Cost of Company owned storage facilities. Cost shall be estimated and recovered based on the latest twelve months actual O&M, Depreciation and return on investment (return calculated based on last rate case factors).

Volumes sold under Rate Schedule 955, and 960 shall not be billed the demand costs, or its equivalent, contained in the PGA computed in accordance with the above-stated formula, but shall be billed the remaining costs contained in the PGA formula. In addition to the PGA less demand costs, or its equivalent, Rate Schedule 955 and 960 shall also have applied to the volumes sold the sum of the Southern Star Central Gas Pipeline, Inc.'s maximum ITS-P and ITS-M commodity rates, adjusted for fuel reimbursement percentages, as set forth in Southern Star Central Gas Pipeline, Inc.'s tariff on file with the Federal Energy Regulatory Commission.

C. COMPUTATION PERIOD

The computation period shall be the subsequent twelve month period ending August 31.

D. COMPUTATION FREQUENCY

The computation shall be made annually or each time a change or changes occur in supplier rates or sources of supply, the cumulative effect of which change or changes is to produce an increase or decrease in the new effective rate paid for purchased gas by at least $.010/Ccf.

E. COSTS INCLUDED

The formula includes only costs which are properly included in FERC Accounts 800, 801, 802, 803, 804, 858, applicable to Kansas; 805, 806, 808, and 809.

F. SETTLEMENT PROVISIONS

Subsequent to the effective date of this clause, the Company shall maintain a continuing monthly comparison of the actual (as billed) cost of gas as shown on the books and records of the Company, exclusive of refunds, and the cost recovery for the same month calculated by applying to the volumes sold during said month the purchased gas cost adjustments calculated pursuant to these purchased gas cost adjustment provisions. For each twelve month period ended August 31, the differences of the comparisons described above including any balance or credit for the previous year shall be accumulated to produce a cumulative balance of over-recovered or under-recovered costs.

An "Actual Cost Adjustment" (ACA) shall be computed by dividing the cumulative balance of under-recovered or over-recovered costs by the volume of total sales during the twelve month period ending on that date. This adjustment shall be rounded to the nearest $.0001 per Ccf and applied to sales billed on or after the first day of the month following the month in which the adjustment has been approved by the Commission. The "Actual Cost Adjustments" shall remain in effect until superseded by subsequent "Actual Cost Adjustments" calculated according to this provision.

The Gas Cost portion of uncollectible accounts is recoverable through the ACA. The cumulative balance of over-recovered or under-recovered costs shall include the Gas Cost portion of uncollectible PGA customer accounts billed under this Schedule during the preceding Computation Year and which remain unpaid. The uncollectible amounts included in the annual ACA computation shall not contain interest or collection fees or charges. This sub-component of the ACA will be a separate line item on Sheet 1 of the Purchased Gas Adjustment.

G. CAPACITY RELEASE

The Company shall forecast, on a monthly basis, the capacity release credits expected to be received (applicable to its Kansas jurisdiction). The Company shall then calculate a Monthly Capacity Release Factor by dividing fifty percent of this total monthly forecast by estimated monthly sales. The Total Capacity Release Factor shall be applied to the Purchased Gas Cost Factor. The Company shall maintain a continuing monthly comparison of 50% of the actual capacity release credits received and the capacity release credits distributed. The differences of the comparisons described above shall be accumulated to produce an Accumulated Capacity Release Balance, that is, a cumulative balance of under or over distributed credits. An Accumulated Capacity Release Factor will be calculated annually by dividing the accumulated balance of under or over distributed credits by the volume of actual sales during the twelve month period ending August 31. The Accumulated Capacity Release Factor will be added to the Monthly Capacity Release Factor to equal the Total Capacity Release Factor. The Accumulated Capacity Release Balance will be adjusted by the monthly capacity release under/over disbursements.

H. OVERRUN PENALTIES

Overrun penalties applicable to the Company's Kansas jurisdiction shall be separately accumulated and shall be administered in compliance with the provisions contained in the Commission Order in Docket No. 190,061-U. The Company shall maintain a continuing monthly comparison of the actual penalties received (applicable to its Kansas jurisdiction) and the amount recovered from its customers. The differences of the comparisons described above shall be accumulated to produce an Accumulated Penalty Balance, that is, a cumulative balance of under or over recovered penalties. An Accumulated Penalty Recovery Factor will be calculated annually by dividing the accumulated balance of under or over recovered penalties by the volume of actual sales during the twelve month period ending August 31. The Accumulated Penalty Recovery Factor will be applied to the Purchased Gas Cost Factor each month. The Accumulated Penalty Balance will be adjusted by the monthly penalty under/over recovery.

I. REPORTING REQUIREMENTS

The Company shall submit to the Commission purchased gas cost filings at least 15 days before the filing is to be effective. Purchased gas cost filings and cost adjustment reports shall use the format prescribed by the Commission.

J. LINE LOSS LIMITATIONS

The Company shall compute one actual line loss for the entire State of Kansas . In the event that the actual line loss (unaccounted for gas) statistic for the computation period exceeds the line loss limit of 4%, the Company will compute the purchased gas adjustment using the limit value rather than the actual operating statistic value.

SECTION 2 - PURCHASED GAS COST REFUND ADJUSTMENT PROCEDURE

A. REFUND PROVISION

1. For the purpose hereof, unless the Kansas Corporation Commission shall otherwise order, refunds or a balance in the refund account in excess of $.002 per Ccf for purchased gas from all suppliers (including interest from the suppliers) in a rate area received by Company from charges paid for natural gas resold to its customers, shall be refunded to such customers as a reduction in the Purchased Gas Adjustment. Within ninety (90) days of the receipt of a refund in excess of $.002 per Ccf for purchased gas from any supplier or the balance of the refund account reaching the equivalent of $.002 per Ccf for purchased gas from all suppliers, the Company shall file with the Commission and propose to make effective, the appropriate

Purchased Gas Adjustment reflecting the decrease and an associated statement showing the computation of the refund adjustment.

2. The refund adjustment per Ccf shall be determined by dividing the appropriate refund amount by the estimated Ccf sales to the rate area as shown on Line 6, Sheet KCC Form PGA-1. The amount of the unit refund adjustment shall be computed to the nearest $.00001 per Ccf.

3. The length of the refund period shall generally be twelve (12) months, except that each refund period may be lengthened or shortened by the Company to avoid a refund materially above or below the refundable amount.

4. After the refunding period is completed, the difference between the refund(s) received from the Company's suppliers and the amount refunded to the respective rate area customers shall be determined and said difference retained in the refund account until such time as a subsequent refund is received from such suppliers. The balance in said refund account shall be added to any subsequent refund before computing a new refund adjustment.

5. In the event any refund received from the Company's supplier is less than the equivalent of $.002 per Ccf for purchased gas for a rate area, said refund shall be credited to the refund account. The credit balance in said account, exclusive of those amounts which have been included in the calculation of refunds then in progress, shall be accumulated to the equivalent of $.002 per Ccf for purchased gas before commencing a subsequent refund as hereinabove provided.

SECTION 3 - PURCHASED GAS COST SURCHARGES

A. Gas Hedge Program

The Company shall operate its Gas Hedge Program pursuant to the relevant order in Docket No. 05-ATMG-617-HED. Costs and revenues associated with any purchase or sale of straight call options, and other alternative risk management strategies, such as call spreads, the net balance of which shall not exceed approved annual budget amount. The estimated net balance shall be recovered as a separate cost component during the months of April through October each year from all PGA customers except irrigation. Any over or under recovery, and any of the allowed budget amount not used by the Company over the course of the Hedge Program year, shall be reflected in the Company's next ACA filing. Costs and revenues generated from the settlement of all financial derivatives shall be flowed back as a separate component during the months of November through March to all PGA customers except irrigation. This settlement component shall be a volumetric charge or credit that is calculated each month from November to March by dividing the monthly estimated hedge payoff amount by the sales volume projected to occur during that respective month. The estimated payoff amount shall be adjusted to the actual payoff amount in the following month's calculation of the settlement component. No settlement component will be added if it is less than $.002 per Ccf, rather the amount will be accumulated until the component results in a rate more than $.002 per Ccf.

Form RF	Index No.
THE STATE CORPORATION COMMISSION OF KANSAS	
ATMOS ENERGY CORPORATION (Name of Issuing Utility)	SCHEDULE VIII GSRS Rider
ENTIRE SERVICE AREA (Territory to which Schedule is applicable)	
No Supplement or separate understanding shall modify the tariff as shown hereon.	Sheet 1 of 1 Sheets

GAS SYSTEM RELIABILITY SURCHARGE RIDER

APPLICABILITY

This rider is applicable to every bill for service provided under each of the Company's sales and transportation rate schedules except where not permitted under a separately negotiated contract with a customer.

RATE

The Gas System Reliability Surcharge (GSRS) shall be applied to each monthly bill. The surcharge shall be as follows:

Residential:	$0.40 per meter per month
Commercial and Public Authority:	$1.29 per meter per month
Schools:	$1.29 per meter per month
Industrial Firm:	$5.78 per meter per month
Small Generator Service:	$5.78 per meter per month
Irrigation Engine:	$3.64 per meter per month
Industrial Interruptible:	$5.78 per meter per month
Transportation:	$17.15 per meter per month

DEFINITIONS AND CONDITIONS

1 The GSRS is intended to recover charges for natural gas public utility plant projects pursuant to K.S.A. 66-2001 through 66-2204.
2 The monthly GSRS charge shall be allocated among customers in the same manner as approved in Docket No. 08-ATMG-280-RTS.
3 The GSRS shall be charged to customers as a monthly fixed charge and not based on volumetric consumption. Such monthly charge shall not Increase more than $0.40 per residential customer over the base rates In effect for the initial filing of a GSRS. Thereafter, each filing shall not Increase the monthly charge for more than $0.40 per residential customer over the most recent filing of a GSRS.
4 At the end of each twelve-month calendar period the GSRS is in effect, the utility shall reconcile the differences between the revenues resulting from a GSRS and the appropriate pretax revenues as found by the Commission for that period and shall submit the reconciliation and a proposed GSRS adjustment to the Commission for approval to recover or refund the difference through adjustments of the GSRS charge.
5 All provisions of this rider are subject to changes made by order of the Commission.

Issued:	January (Month)	26, (Day)	2012 (Year)
Effective:	Upon Commission Approval (Month)	(Day)	(Year)
By:	(Signature of Officer)		VP-Reg & Public Affairs (Title)

Form RF

Index No.

THE STATE CORPORATION COMMISSION OF KANSAS

ATMOS ENERGY CORPORATION
(Name of Issuing Utility)

SCHEDULE IX Customer Rate Stabilization

ENTIRE SERVICE AREA
(Territory to which Schedule is applicable)

No Supplement or separate understanding shall modify the tariff as shown hereon.

SCHEDULE IX – CUSTOMER RATE STABILIZATION

APPLICABILITY

This rider is applicable to every bill for service provided under each of the Company's sales and transportation rate schedules except where not permitted under a separately negotiated contract with a customer.

PURPOSE

This mechanism is designed to provide annual earnings transparency. If, through the implementation of the provisions of this mechanism, it is determined that rates should be decreased or increased, then rates will be adjusted accordingly in the manner as set forth herein. The rate adjustments implemented under this mechanism will reflect annual changes in the Company's cost of service and rate base.

DEFINITIONS

1. The **Annual Evaluation Date** shall be the date Company will make its annual filing under this mechanism. The Annual Evaluation Date shall be no later than October 1of each year. This filing shall be made in electronic form where practicable.
2. The **Evaluation Period** is defined as the twelve month period ending June 30 of each year.
3. The **Rate Effective Period** is defined as the twelve month period in which rates determined under this mechanism shall be in effect. The Rate Effective Period shall run from January 1 to December 31.

RATE MECHANISM FILING

The Company shall file with the Commission the schedules specified below for the twelve month period ending June 30 of each year (the "Evaluation Period"), with the filing to be made no later than October 1. The schedules will include the following:

Section 3 - Summary of Rate Base, Operating Income and Rate of Return
Section 4 – Plant in Service
Section 5 - Accumulated Provision for Depreciation and Amortization
Section 6 – Working Capital
Section 7 – Capital and Cost of Money
Section 9 – Test Year and Pro Forma Income Statements
Section 10 – Depreciation and Amortization
Section 11 – Taxes
Section 12 – Allocation Rates
Section 14 – Rate Base Offsets
Section 17 - Revenue, Sales, Customer Data
Section 18 – Proposed Tariffs

Issued:	January	26,	2012
	(Month)	(Day)	(Year)
Effective:	Upon Commission Approval		
	(Month)	(Day)	(Year)
By:		VP-Reg & Public Affairs	
	(Signature of Officer)	(Title)	

The schedules will provide the Company's actual net plant in service, construction work in progress, accumulated deferred income taxes, inventory, working capital, and other rate base components. The schedules shall also show the utility's depreciation expense, operating and maintenance expense, income taxes, taxes other than income taxes, and other components of income for return, its revenues, and its capital structure (based on a 13-month average), cost of debt, overall cost of capital, and return on common equity as approved in the Company's latest general rate case by the Commission.

A. The Company shall establish a regulatory asset to record all costs incurred in connection with the acquisition, installation operation (including related depreciation) for the following natural gas utility plant projects:
   1) Mains, valves, service lines, regulator stations, vaults and other pipeline system components installed to comply with state or federal safety requirements as replacements for existing facilities; main relining projects, service line insertion projects, joint encapsulation projects and other similar projects extending the useful life or enhancing the integrity of pipeline system components undertaken to comply with state or federal safety requirements; and

   2) facility relocations required due to construction or improvement of a highway, road, street, public way or other public work by or on behalf of the United States, this state, a political subdivision of this state or another entity having the power of eminent domain provided that the costs related to such projects have not been reimbursed to the natural gas public utility.

   The Company may record interest on the balance in the regulatory asset account based on the pretax cost of capital last approved for the utility until such amounts are included in and recovered through rates established in a subsequent rate mechanism filing.

B. The filing will include all applicable accounting and pro forma adjustments historically permitted or required by the Commission for the Company,

C. The filing will include pro-forma adjustments to annualize costs and revenue billing determinants for the Rate Effective Period,

D. The filing will include pro-forma or other adjustments required to properly account for atypical, unusual, or nonrecurring events,

E. The filing will include other information from the Company's books and records similar to that provided in response to initial discovery requests issued by Commission staff in a general rate case proceeding.

F. The Company also shall provide a schedule demonstrating the "proof of revenues" relied upon to calculate the proposed rate for the Rate Effective Period. The proposed rates shall conform as nearly as is practicable to the revenue allocation principles approved in the most recent proceeding. The Company shall also include all costs incurred by the Citizens' Utility Ratepayer Board ("CURB") office and the Commission

Staff in their review of these annual filings under this mechanism. These costs will be included in the company's operating and maintenance costs.

G. These schedules shall identify the rate adjustments necessary for the Rate Effective Period,
   1) If Company's earnings during the Evaluation Period exceed the latest allowed return on common equity, the Company shall calculate an adjustment to rates to refund the revenue required to achieve a return on equity for the Evaluation Period equal to the return established in the last general rate order.
   2) If Company's earnings are below the allowed return on common equity established in the latest general rate order, the Company shall calculate an adjustment in rates to collect the additional revenue required to increase its return on equity for the Evaluation Period to the allowed percentage.

VERIFICATION

A sworn statement shall be filed by Company's Vice President, Regulatory Affairs for Kansas Operations affirming that the filed schedules are in compliance with the provisions of this mechanism and are true and correct to the best of his/her knowledge, information and belief. No testimony shall be filed.

EVAULATION PROCEDURES

The Commission staff and CURB shall have 60 days to review the Company's filed schedules and issue its recommendation to the Commission for the change in rates under this tariff. The Company will be prepared to provide supplemental information as may be requested to ensure adequate review by the Commission and CURB. The Commission shall propose any adjustments it determines to be required to bring the schedules into compliance with the above provisions.