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PUBLIC SERVICE COMMISSION

ATMOS ENERGY CORPORATION

MID-STATES / KENTUCKY DIVISION

IN THE MATTER OF	) CASE NO. 2006-00464
RATE APPLICATION BY	)
ATMOS ENERGY CORPORATION	)
MID-STATES/KENTUCKY	)

RESPONSE OF ATMOS ENERGY CORPORATION

MID-STATES DIVISION

AG DATA REQUEST DATED FEBRUARY 20, 2007

(AG DATA REQUEST NO. 1)

DR 200 – DR 208

MARCH 16, 2007

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 200
Witness: Gary Smith

Data Request:

Please provide the calculation of the Gas Cost Adjustment Riders for the most recent four quarters.

Response:

The calculations for the requested Gas Cost Adjustments are attached hereto and collectively labeled AG DR1-200 ATT.

Please note that page 5 of Exhibit D for each of the attached GCA filings is being filed subject to the terms of a confidentiality petition accompanying Atmos' responses to the Attorney General's Initial Data Requests.

Atmos energy

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PUBLIC SERVICE COMMISSION

January 9, 2007

Ms. Elizabeth O'Donnell, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602

Re: Case No. 2006-00568

Dear Ms. O'Donnell:

On December 27, 2006 Atmos Energy filed with the Kentucky Public Service Commission its quarterly Gas Cost Adjustment under the provision of our Gas Cost Adjustment Clause, to be effective February 1, 2007. Since that time forecasted market prices (as reflected in the NYMEX) have declined. Therefore, we are filing the enclosed original and three (3) copies of a REVISED notice under the same provisions. In this filing, we are only providing the exhibits which changed from our December 27 filing. **This filing contains a Petition of Confidentiality and confidential documents.**

Please indicate receipt of this filing by stamping and dating the enclosed duplicate of this letter and returning it in the self-addressed stamped envelope to the following address:

Atmos Energy Corporation
5430 LBJ Freeway, Suite 600
Dallas, TX 75240

If you have any questions, feel free to call me at 972-855-3011.

Sincerely,

Thomas J Morel

Thomas J. Morel
Senior Rate Analyst, Rate Administration

Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
JAN 11 2007
PUBLIC SERVICE COMMISSION

In the Matter of:

REVISED GAS COST ADJUSTMENT	)	**Case No. 2006 - 00568**
FILING OF	)	
ATMOS ENERGY CORPORATION	)	

NOTICE

QUARTERLY FILING

For The Period

February 1, 2007 - April 30, 2007

Attorney for Applicant

Mark R. Hutchinson
1700 Frederica St.
Suite 201
Owensboro, Kentucky 42301

January 9, 2007

Atmos Energy Corporation, ("the Company"), is duly qualified under the laws of the Commonwealth of Kentucky to do its business. The Company is an operating public utility engaged in the business of purchasing, transporting and distributing natural gas to residential, commercial and industrial users in western and central Kentucky. The Company's principal operating office and place of business is 2401 New Hartford Road, Owensboro, Kentucky 42301. Correspondence and communications with respect to this notice should be directed to:

Gary L. Smith
Vice President - Marketing &
Regulatory Affairs/Kentucky Division
Atmos Energy Corporation
Post Office Box 866
Owensboro, Kentucky 42302

Mark R. Hutchinson
Attorney for Applicant
1700 Frederica St.
Suite 201
Owensboro, Kentucky 42301

Thomas J. Morel
Senior Rate Analyst, Rate Administration
Atmos Energy Corporation
5430 LBJ Freeway, Suite 600
Dallas, Texas 75240

The Company gives notice to the Kentucky Public Service Commission, hereinafter "the Commission", pursuant to the Gas Cost Adjustment Clause contained in the Company's settlement gas rate schedules in Case No. 99-070.

The Company hereby files Twentieth Revised Sheet No. 4, Twentieth Revised Sheet No. 5 and Twentieth Revised Sheet No. 6 to its PSC No. 1, Rates, Rules and Regulations for Furnishing Natural Gas to become effective February 1, 2007.

The REVISED Gas Cost Adjustment (GCA) for firm sales service is \$8.5885 per Mcf, \$7.7152 per Mcf for high load factor firm sales service, and \$7.7152 per Mcf for interruptible sales service. The supporting calculations for the Twentieth Revised Sheet No. 5 are provided in the following Exhibits:

Exhibit A - Summary of Derivations of Gas Cost Adjustment (GCA) ....
Exhibit B - Expected Gas Cost (EGC) Calculation ....
Exhibit C - Rates used in the Expected Gas Cost (EGC) Calculation .....

Since this is a REVISED GCA Filing, we are only providing the applicable Exhibits.

Since the Company's last GCA filing, Case No. 2006-00428, the following changes have occurred in its pipeline and gas supply commodity rates for the GCA period.

1. The commodity rates per MMbtu used are based on historical estimates and/or current data for the quarter February 2007 through April 2007, as shown in Exhibit C, page 19.

2. The Expected Commodity Gas Cost will be approximately $7.4815 MMbtu for the quarter February 2007 through April 2007, as compared to $8.0540 per MMbtu used for the quarter of November 2006 through January 2007.

3. The Company's notice sets out a new Correction Factor of $0.0551 per Mcf, which will remain in effect until at least April 30, 2007.

The GCA tariff as approved in Case No. 92-558 provides for a Correction Factor (CF) which compensates for the difference between the expected gas cost and the actual gas cost for prior periods. A revision to the GCA tariff effective December 1, 2001, Filing No. T62-1253, provides that the Correction Factor be filed on a quarterly basis. The Company is filing its updated Correction Factor that is based upon the balance in the Company's Account 191 as of October 31, 2006. The calculation for the Correction Factor is shown on Exhibit D, Page 1.

WHEREFORE, Atmos Energy Corporation requests this Commission, pursuant to the Commission's order in Case No. 99-070, to approve the REVISED Gas Cost Adjustment (GCA) as filed in Twentieth Revised Sheet No. 5; and Twentieth Revised Sheet No. 6 setting out the General Transportation Tariff Rate T-2 for each respective sales rate for meter readings made on and after February 1, 2007.

DATED at Dallas Texas, this 9th Day of January, 2007.

ATMOS ENERGY CORPORATION

By: Thomas J. Morel

Thomas J. Morel
Senior Rate Analyst, Rate Administration
Atmos Energy Corporation

ATMOS ENERGY CORPORATION

Current Rate Summary

Case No. 2006-00000

Firm Service

Base Charge:			
Residential	-	$7.50	per meter per month
Non-Residential	-	20.00	per meter per month
Carriage (T-4)	-	220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

Rate per Mcf[2]			Sales (G-1)		Transport (T-2)		Carriage (T-4)		
First	300[1]	Mcf	@	9.7785 per Mcf	@	2.2472 per Mcf	@	1.1900 per Mcf	(R, N, N)
Next	14,700[1]	Mcf	@	9.2475 per Mcf	@	1.7162 per Mcf	@	0.6590 per Mcf	(R, N, N)
Over	15,000	Mcf	@	9.0185 per Mcf	@	1.4872 per Mcf	@	0.4300 per Mcf	(R, N, N)

High Load Factor Firm Service

HLF demand charge/Mcf	@	4.5576	@	4.5576 per Mcf of daily Contract Demand	(N)

Rate per Mcf[2]							
First	300[1]	Mcf	@	8.9052 per Mcf	@	1.3739 per Mcf	(R, N)
Next	14,700[1]	Mcf	@	8.3742 per Mcf	@	0.8429 per Mcf	(R, N)
Over	15,000	Mcf	@	8.1452 per Mcf	@	0.6139 per Mcf	(R, N)

Interruptible Service

Base Charge	-	$220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

Rate per Mcf[2]			Sales (G-2)		Transport (T-2)		Carriage (T-3)		
First	15,000[1]	Mcf	@	8.2452 per Mcf	@	0.7139 per Mcf	@	0.5300 per Mcf	(R, N, N)
Over	15,000	Mcf	@	8.0743 per Mcf	@	0.5430 per Mcf	@	0.3591 per Mcf	(R, N, N)

[1] All gas consumed by the customer (sales, transportation, and carriage; firm, high load factor, and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] DSM, GRI and MLR Riders may also apply, where applicable.

ATMOS ENERGY CORPORATION

Current Gas Cost Adjustments

Case No. 2006-00000

Applicable

For all Mcf billed under General Sales Service (G-1) and Interruptible Sales Service (G-2).

Gas Charge = GCA

GCA = EGC + CF + RF + PBRRF

Gas Cost Adjustment Components	G - 1	HLF G - 1	G-2	
EGC (Expected Gas Cost Component)	8.5387	7.6654	7.6654	(R, R, R)
CF (Correction Factor)	0.0551	0.0551	0.0551	(I, I, I)
RF (Refund Adjustment)	(0.0554)	(0.0554)	(0.0554)	(N, N, N)
PBRRF (Performance Based Rate Recovery Factor)	0.0501	0.0501	0.0501	(I, I, I)
GCA (Gas Cost Adjustment)	$8.5885	$7.7152	$7.7152	(R, R, R)

ISSUED: January 9, 2007 **Effective:** February 1, 2007

(Issued by Authority of an Order of the Public Service Commission in Case No. 2006-00000.)

ISSUED BY: Gary L. Smith Vice President - Marketing & Regulatory Affairs/Kentucky Division

ATMOS ENERGY CORPORATION

Current Transportation and Carriage

Case No. 2006-00000

Case No. 2004-00398

The General Transportation Rate T-2 and Carriage Service (Rates T-3 and T-4) for each respective service net monthly rate is as follows:

System Lost and Unaccounted gas percentage: 1.38%

					Simple Margin		Non-Commodity		Gross Margin		
Transportation Service (T-2)[1]											
a) Firm Service											
First	300 [2]	Mcf		@	$1.1900	+	$1.0572	=	$2.2472	per Mcf	(N)
Next	14,700 [2]	Mcf		@	0.6590	+	1.0572	=	1.7162	per Mcf	(N)
All over	15,000	Mcf		@	0.4300	+	1.0572	=	1.4872	per Mcf	(N)
b) High Load Factor Firm Service (HLF)											
Demand				@	$0.0000	+	4.5576	=	$4.5576	per Mcf of daily contract demand	(N)
First	300 [2]	Mcf		@	$1.1900	+	$0.1839	=	$1.3739	per Mcf	(N)
Next	14,700 [2]	Mcf		@	0.6590	+	0.1839	=	0.8429	per Mcf	(N)
All over	15,000	Mcf		@	0.4300	+	0.1839	=	0.6139	per Mcf	(N)
c) Interruptible Service											
First	15,000 [2]	Mcf		@	$0.5300	+	$0.1839	=	$0.7139	per Mcf	(N)
All over	15,000	Mcf		@	0.3591	+	0.1839	=	0.5430	per Mcf	(N)
Carriage Service[3]											
Firm Service (T-4)											
First	300	[2] Mcf		@	$1.1900	+	$0.0000	=	$1.1900	per Mcf	(N)
Next	14,700	[2] Mcf		@	0.6590	+	0.0000	=	0.6590	per Mcf	(N)
All over	15,000	[2] Mcf		@	0.4300	+	0.0000	=	0.4300	per Mcf	(N)
Interruptible Service (T-3)											
First	15,000 [2]	Mcf		@	$0.5300	+	$0.0000	=	$0.5300	per Mcf	(N)
All over	15,000	Mcf		@	0.3591	+	0.0000	=	0.3591	per Mcf	(N)

[1] Includes standby sales service under corresponding sales rates. GRI Rider may also apply.

[2] All gas consumed by the customer (Sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[3] Excludes standby sales service.

ISSUED: January 9, 2007 **Effective:** February 1, 2007

(Issued by Authority of an Order of the Public Service Commission in Case No. 2006-00000.)

ISSUED BY: Gary L. Smith Vice President - Marketing & Regulatory Affairs/Kentucky Division

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Sales Service

Line No.	Description	Case No. 2006-00428 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	**G-1**			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 300 Mcf	1.1900	1.1900	0.0000
5	Next 14,700 Mcf	0.6590	0.6590	0.0000
6	Over 15,000 Mcf	0.4300	0.4300	0.0000
7				
8	Gas Cost Adjustment Components			
9	EGC (Expected Gas Cost):			
10	Commodity	8.0540	7.4815	(0.5725)
11	Demand	1.0572	1.0572	0.0000
12	Take-Or-Pay	0.0000	0.0000	0.0000
13	Transition Costs	0.0000	0.0000	0.0000
14	Total EGC	9.1112	8.5387	(0.5725)
15	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
16	CF (Correction Factor)	(0.3088)	0.0551	0.3639
17	RF (Refund Adjustment)	(0.0554)	(0.0554)	0.0000
18	PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0501	0.0102
19	GCA (Gas Cost Adjustment)	8.7869	8.5885	(0.1984)
20	Total Billing Cost of Gas	8.7869	8.5885	(0.1984)
21				
22	Commodity Charge (GCA included):			
23	First 300 Mcf	9.9769	9.7785	(0.1984)
24	Next 14,700 Mcf	9.4459	9.2475	(0.1984)
25	Over 15,000 Mcf	9.2169	9.0185	(0.1984)
26				
27	**HLF (High Load Factor)**			
28				
29	Commodity Charge (Base Rate per Case No. 99-070):			
30	First 300 Mcf	1.1900	1.1900	0.0000
31	Next 14,700 Mcf	0.6590	0.6590	0.0000
32	Over 15,000 Mcf	0.4300	0.4300	0.0000
33				
34	Gas Cost Adjustment Components			
35	EGC (Expected Gas Cost):			
36	Commodity	8.0540	7.4815	(0.5725)
37	Demand	0.1839	0.1839	0.0000
38	Take-Or-Pay	0.0000	0.0000	0.0000
39	Transition Costs	0.0000	0.0000	0.0000
40	Total EGC	8.2379	7.6654	(0.5725)
41	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
42	CF (Correction Factor)	(0.3088)	0.0551	0.3639
43	RF (Refund Adjustment)	(0.0554)	(0.0554)	0.0000
44	PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0501	0.0102
45	GCA (Gas Cost Adjustment)	7.9136	7.7152	(0.1984)
46	Total Cost of Gas to Bill (excludes MDQ Demand)	7.9136	7.7152	(0.1984)
47				
48	Commodity Charge (GCA included):			
49	First 300 Mcf	9.1036	8.9052	(0.1984)
50	Next 14,700 Mcf	8.5726	8.3742	(0.1984)
51	Over 15,000 Mcf	8.3436	8.1452	(0.1984)
52				
53	HLF Demand			
54	Contract Demand Factor	4.5576	4.5576	0.0000

Atmos Energy Corporation
Comparison of Current and Previous Cases
Interruptible Sales Service

Line No.	Description	Case No. 2006-00428	Case No. 2006-00000	Difference
		$/Mcf	$/Mcf	$/Mcf
1	G-2			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 15,000 Mcf	0.5300	0.5300	0.0000
5	Over 15,000 Mcf	0.3591	0.3591	0.0000
6				
7	Gas Cost Adjustment Components			
8	Expected Gas Cost (EGC):			
9	Commodity	8.0540	7.4815	(0.5725)
10	Demand	0.1839	0.1839	0.0000
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0000	0.0000	0.0000
13	Total EGC	8.2379	7.6654	(0.5725)
14	Less: Base Cost of Gas (BCOG)	0.0000	0.0000	0.0000
15	Correction Factor (CF)	(0.3088)	0.0551	0.3639
16	Refund Adjustment (RF)	(0.0554)	(0.0554)	0.0000
17	Performance Based Rate Recovery Factor (PBRRF)	0.0399	0.0501	0.0102
18	Gas Cost Adjustment (GCA)	7.9136	7.7152	(0.1984)
19	Total Cost of Gas to Bill	7.9136	7.7152	(0.1984)
20				
21	Commodity Charge (GCA included):			
22	First 15,000 Mcf	8.4436	8.2452	(0.1984)
23	Over 15,000 Mcf	8.2727	8.0743	(0.1984)
24				
25				

Line No.		Case No.	Effective Date	G - 1	G - 1 / HLF	G - 2
26	Monthly Refund Factor					
29	1 -	1999-070 L	07/01/01	0.0000	0.0000	0.0000
30	2 -	1999-070 M	08/01/01	0.0000	0.0000	0.0000
31	3 -	1999-070 N	10/01/01	0.0000	0.0000	0.0000
32	4 -	1999-070 O	11/01/01	(0.0019)	(0.0019)	(0.0019)
33	5 -	1999-070 P	05/03/02	0.0000	0.0000	0.0000
34	6 -	2002-00251	08/01/02	(0.0095)	(0.0095)	(0.0019)
35	7 -	2002-00359	11/01/02	(0.1574)	(0.1574)	(0.0391)
36	8 -	2003-00377	11/01/03	(0.0006)	(0.0006)	(0.0006)
37	9 -	2004-00269	08/01/04	(0.0048)	(0.0048)	(0.0048)
38	10 -	2005-00399	11/01/05	(0.0017)	(0.0017)	(0.0017)
39	11 -	2006-00000	11/01/06	(0.0554)	(0.0554)	(0.0554)
40	12 -					
41						
42	Total Supplier Refund Adjustment (RF)			(0.0554)	(0.0554)	(0.0554)
43						

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description	Case No. 2006-00428 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	**T-2 \ G-1**			
2				
3				
4	Simple Margin (Base Rate per Case No. 99-070):			
5	First 300 Mcf	1.1900	1.1900	0.0000
6	Next 14,700 Mcf	0.6590	0.6590	0.0000
7	Over 15,000 Mcf	0.4300	0.4300	0.0000
8				
9	Non-Commodity Components:			
10	Demand	1.0572	1.0572	0.0000
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0000	0.0000	0.0000
13	RF (Refund Adjustment)	0.0000	0.0000	0.0000
14	Total	1.0572	1.0572	0.0000
15				
16	Gross Margin:			
17	First 300 Mcf	2.2472	2.2472	0.0000
18	Next 14,700 Mcf	1.7162	1.7162	0.0000
19	Over 15,000 Mcf	1.4872	1.4872	0.0000
20				
21	***T-2\G-1\HLF***			
22				
23	Simple Margin (Base Rate per Case No. 99-070):			
24	First 300 Mcf	1.1900	1.1900	0.0000
25	Next 14,700 Mcf	0.6590	0.6590	0.0000
26	Over 15,000 Mcf	0.4300	0.4300	0.0000
27				
28	Non-Commodity Components:			
29	Demand	0.1839	0.1839	0.0000
30	Take-Or-Pay	0.0000	0.0000	0.0000
31	Transition Costs	0.0000	0.0000	0.0000
32	RF (Refund Adjustment)	0.0000	0.0000	0.0000
33	Total	0.1839	0.1839	0.0000
34				
35	Gross Margin (Excluding HLF Demand):			
36	First 300 Mcf	1.3739	1.3739	0.0000
37	Next 14,700 Mcf	0.8429	0.8429	0.0000
38	Over 15,000 Mcf	0.6139	0.6139	0.0000
39				
40	HLF Demand			
41	Contract Demand Factor	4.5576	4.5576	0.0000
42				

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description			Case No. 2006-00428	Case No. 2006-00000	Difference
				$/Mcf	$/Mcf	$/Mcf
1	*Carriage Service*					
2						
3	Firm Service (T-4)					
4	Simple Margin (Base Rate per Case No. 99-070):					
5	First	300	Mcf	1.1900	1.1900	0.0000
6	Next	14,700	Mcf	0.6590	0.6590	0.0000
7	Over	15,000	Mcf	0.4300	0.4300	0.0000
8						
9	Non-Commodity Components:					
11	Take-Or-Pay			0.0000	0.0000	0.0000
13	RF (Refund Adjustment)			0.0000	0.0000	0.0000
14	Total			0.0000	0.0000	0.0000
15						
16	Gross Margin:					
17	First	300	Mcf	1.1900	1.1900	0.0000
18	Next	14,700	Mcf	0.6590	0.6590	0.0000
19	Over	15,000	Mcf	0.4300	0.4300	0.0000
20						

Comparison of Current and Previous Cases
Interruptible Transportation and Carriage Service

Line No.	Description			Case No. 2006-00428 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	**General Transporation (T-2)**					
2						
3	Interruptible Service (G-2)					
4	Simple Margin (Base Rate per Case No. 99-070):					
5	First	15,000	Mcf	0.5300	0.5300	0.0000
6	Over	15,000	Mcf	0.3591	0.3591	0.0000
7						
8	Non-Commodity Components:					
9	Demand			0.1839	0.1839	0.0000
10	Take-Or-Pay			0.0000	0.0000	0.0000
11	Transition Costs			0.0000	0.0000	0.0000
12	RF (Refund Adjustment)			0.0000	0.0000	0.0000
13	Total			0.1839	0.1839	0.0000
14						
15	Gross Margin:					
16	First	15,000	Mcf	0.7139	0.7139	0.0000
17	Over	15,000	Mcf	0.5430	0.5430	0.0000
18						
19	**Carriage Service**					
20						
21	Carriage Service (T-3)					
22	Simple Margin (Base Rate per Case No. 99-070):					
23	First	15,000	Mcf	0.5300	0.5300	0.0000
24	Over	15,000	Mcf	0.3591	0.3591	0.0000
25						
26	Non-Commodity Components:					
28	Take-Or-Pay			0.0000	0.0000	0.0000
30	RF (Refund Adjustment)			0.0000	0.0000	0.0000
31	Total			0.0000	0.0000	0.0000
32						
33	Gross Margin:					
34	First	15,000	Mcf	0.5300	0.5300	0.0000
35	Over	15,000	Mcf	0.3591	0.3591	0.0000
36						

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Texas Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**SL to Zone 2**							
2	NNS Contract #	N0210		12,617,673				
3	Base Rate		20		0.3088	3,896,336	3,896,336	
4	GSR		20		0.0000	0		0
5	TCA Adjustment		20		0.0000	0	0	
6	Unrec TCA Surch		20		0.0000	0	0	
7	ISS Credit		20		0.0000	0	0	
8	Misc Rev Cr Adj		20		0.0000	0	0	
9	GRI		20		0.0000	0	0	
6								
7	Total SL to Zone 2			12,617,673		3,896,336	3,896,336	0
8								
9	**SL to Zone 3**							
10	NNS Contract #	N0340		27,480,375				
11	Base Rate		20		0.3543	9,736,297	9,736,297	
12	GSR		20		0.0000	0		0
13	TCA Adjustment		20		0.0000	0	0	
14	Unrec TCA Surch		20		0.0000	0	0	
15	ISS Credit		20		0.0000	0	0	
16	Misc Rev Cr Adj		20		0.0000	0	0	
17	GRI		20		0.0000	0	0	
18								
19	FT Contract #	3355		3,130,605				
20	Base Rate		24		0.2494	780,773	780,773	
21	GSR		24		0.0000	0		0
22	TCA Adjustment		24		0.0000	0	0	
23	Unrec TCA Surch		24		0.0000	0	0	
24	ISS Credit		24		0.0000	0	0	
25	Misc Rev Cr Adj		24		0.0000	0	0	
26	GRI		24		0.0000	0	0	
27								
28								
29	Total SL to Zone 3			30,610,980		10,517,070	10,517,070	0
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Texas Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**Zone 1 to Zone 3**							
2	FT Contract #	3355		2,344,395				
3	Base Rate		24		0.2194	514,360	514,360	
4	GSR		24		0 0000	0		0
5	TCA Adjustment		24		0.0000	0	0	
6	Unrec TCA Surch		24		0 0000	0	0	
7	ISS Credit		24		0.0000	0	0	
8	Misc Rev Cr Adj		24		0.0000	0	0	
9	GRI		24		0.0000	0	0	
6								
7	Total Zone 1 to Zone 3			2,344,395		514,360	514,360	0
8								
9	**SL to Zone 4**							
10	NNS Contract #	N0410		3,320,769				
11	Base Rate		20		0 4190	1,391,402	1,391,402	
12	GSR		20		0.0000	0		0
13	TCA Adjustment		20		0.0000	0	0	
14	Unrec TCA Surch		20		0.0000	0	0	
15	ISS Credit		20		0.0000	0	0	
16	Misc Rev Cr Adj		20		0.0000	0	0	
17	GRI		20		0.0000	0	0	
18								
19	FT Contract #	3819		1,277,500				
20	Base Rate		24		0.3142	401,391	401,391	
21	GSR		24		0.0000	0		0
22	TCA Adjustment		24		0.0000	0	0	
23	Unrec TCA Surch		24		0.0000	0	0	
24	ISS Credit		24		0.0000	0	0	
25	Misc Rev Cr Adj		24		0.0000	0	0	
26	GRI		24		0.0000	0	0	
27								
28	Total SL to Zone 4			4,598,269		1,792,793	1,792,793	0
29								
30	Total SL to Zone 2			12,617,673		3,896,336	3,896,336	0
31	Total SL to Zone 3			30,610,980		10,517,070	10,517,070	0
32	Total Zone 1 to Zone 3			2,344,395		514,360	514,360	0
33								
34	Total Texas Gas			50,171,317		16,720,559	16,720,559	0
35								
36								
37	Vendor Reservation Fees (Fixed)					0	0	
38								
39	TOP & Direct Billed Transition costs					0		
40								
41	Total Texas Gas Area Non-Commodity					16,720,559	16,720,559	0
42								
43								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Tennessee Gas

				(1)	(2)	(3)	(4)	(5)
						Non-Commodity		
Line No.	Description		Tariff Sheet No.	Annual Units	Rate	Total	Demand	Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**0 to Zone 2**							
2	FT-G Contract #	2546.1		12,844	9.0600			
3	Base Rate		23B		9.0600	116,367	116,367	
4	Settlement Surcharge		23B		0.0000	0		0
5	PCB Adjustment		23B		0.0000	0		0
6								
7	FT-G Contract #	2548.1		4,363	9.0600			
8	Base Rate		23B		9.0600	39,529	39,529	
9	Settlement Surcharge		23B		0.0000	0		0
10	PCB Adjustment		23B		0.0000	0		0
11								
12	FT-G Contract #	2550.1		5,739	9.0600			
13	Base Rate		23B		9.0600	51,995	51,995	
14	Settlement Surcharge		23B		0.0000	0		0
15	PCB Adjustment		23B		0.0000	0		0
16								
17	FT-G Contract #	2551.1		4,447	9.0600			
18	Base Rate		23B		9.0600	40,290	40,290	
19	Settlement Surcharge		23B		0.0000	0		0
20	PCB Adjustment		23B		0.0000	0		0
21								
22								
23	*Total Zone 0 to 2*			27,393		248,181	248,181	0
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Tennessee Gas

			(1)	(2)	(3)	(4)	(5)
						Non-Commodity	
Line No.	**Description**	**Tariff** *Sheet No.*	**Annual** *Units*	*Rate*	**Total**	**Demand**	**Transition Costs**
			MMbtu	$/MMbtu	$	$	$
1	**1 to Zone 2**						
2	FT-G Contract # 2546		114,156	7.6200			
3	Base Rate	23B		7.6200	869,869	869,869	
4	Settlement Surcharge	23B		0.0000	0		0
5	PCB Adjustment	23B		0.0000	0		0
6							
7	FT-G Contract # 2548		44,997	7.6200			
8	Base Rate	23B		7.6200	342,877	342,877	
9	Settlement Surcharge	23B		0.0000	0		0
10	PCB Adjustment	23B		0.0000	0		0
11							
12	FT-G Contract # 2550		59,741	7.6200			
13	Base Rate	23B		7.6200	455,226	455,226	
14	Settlement Surcharge	23B		0.0000	0		0
15	PCB Adjustment	23B		0.0000	0		0
16							
17	FT-G Contract # 2551		45,058	7.6200			
18	Base Rate	23B		7.6200	343,342	343,342	
19	Settlement Surcharge	23B		0.0000	0		0
20	PCB Adjustment	23B		0.0000	0		0
21							
22	Total Zone 1 to 2		263,952		2,011,314	2,011,314	0
23							
24	Total Zone 0 to 2		27,393		248,181	248,181	0
25							
26	Total Zone 1 to 2 and Zone 0 to 2		291,345		2,259,495	2,259,495	0
27							
28	**Gas Storage**						
29	Production Area:						
30	Demand	27	34,968	2.0200	70,635	70,635	
31	Space Charge	27	4,916,148	0.0248	121,920	121,920	
32	Market Area:						
33	Demand	27	237,408	1.1500	273,019	273,019	
34	Space Charge	27	10,846,308	0.0185	200,657	200,657	
35	Total Storage				666,231	666,231	
36							
37	Vendor Reservation Fees (Fixed)				0	0	
38							
39	TOP & Direct Billed Transition costs				0	0	0
40							
41	Total Tennessee Gas Area FT-G Non-Commodity				2,925,726	2,925,726	0
42							
43							
44							
45							
46							
47							
48							
49							
50							
51							

Atmos Energy Corporation
Expected Gas Cost - Commodity
Purchases in Texas Gas Service Area

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1							
2							
3							
4							
5							
6							
7	Firm Transportation				91,000		
8	Indexed Gas Cost					6.5910	599,781
9	Base (Weighted on MDQs)	25				0.0439	3,995
10	TCA Adjustment	25				0.0000	0
11	Unrecovered TCA Surcharge	25				0.0000	0
12	Cash-out Adjustment	25				0.0000	0
13	GRI	25				0.0000	0
14	ACA	25				0.0016	146
15	Fuel and Loss Retention @	36	1.73%			0.1160	10,556
16						6.7525	614,478
17	No Notice Storage						
18	Net (Injections)/Withdrawals				340,681		
19	Indexed Gas Cost					6.5910	2,245,428
20	Commodity (Zone 3)	20				0.0506	17,238
21	Fuel and Loss Retention @	36	3.17%			0.2158	73,519
22						6.8574	2,336,185
23							
24							
25	Total Purchases in Texas Area				431,681	6.8353	2,950,663
26							
27							

Line No.	Used to allocate transportation non-commodity	Annualized MDQs in MMbtu	Allocation	Commodity Charge $/MMbtu		Weighted Average
28						
29						
30						
31						
32	Texas Gas					
33	SL to Zone 2	12,617,673	25.15%	$0.0399	$	0.0100
34	SL to Zone 3	30,610,980	61.01%	0.0445		0.0271
35	1 to Zone 3	2,344,395	4.67%	0.0422		0.0020
36	SL to Zone 4	4,598,269	9.17%	0.0528		0.0048
37	Total	50,171,317	100.00%		$	0.0439
38						
39	Tennessee Gas					
40	0 to Zone 2	27,393	9.40%	0.0880	$	0.0083
41	1 to Zone 2	263,952	90.60%	0.0776		0.0703
42	Total	291,345	100.00%		$	0.0786
43						

Atmos Energy Corporation
Expected Gas Cost - Commodity
Purchases in Tennessee Gas Service Area

Line No.	Description	Tariff Sheet No.		Purchases (1) Mcf	Purchases (2) MMbtu	Rate (3) $/MMbtu	Total (4) $
1	FT-A and FT-G				659,675		
2	Indexed Gas Cost					6.5910	4,347,918
3	Base Commodity (Weighted on MDQs)					0.0786	51,850
4	GRI	23C				0.0000	0
5	ACA	23C				0.0016	1,055
6	Transition Cost	23C				0.0000	0
7	Fuel and Loss Retention	29	4.28%			0.2947	194,406
8						6.9659	4,595,229
9							
10							
11	FT-GS				120,440		
12	Indexed Gas Cost					6.5910	793,820
13	Base Rate	20				0.5844	70,385
14	GRI	20				0.0000	0
15	ACA	20				0.0016	193
16	PCB Adjustment	20				0.0000	0
17	Settlement Surcharge	20				0.0000	0
18	Fuel and Loss Retention	29	4.28%			0.2947	35,494
19						7.4717	899,892
20							
21							
22	Gas Storage						
23	FT-A & FT-G Market Area (Injections)/Withdrawals				215,385		
24	Indexed Gas Cost/Storage					6.5400	1,408,618
25	Injection Rate	27				0.0102	2,197
26	Fuel and Loss Retention	27	1.49%			0.0989	21,302
27	Total					6.6491	1,432,117
28							
29							
30							
31							
32							
33							
34							
35							
36							
37	Total Tennessee Gas Zones				995,500	6.9586	6,927,238
38							
39							

Atmos Energy Corporation
Expected Gas Cost
Trunkline Gas

Commodity

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	Firm Transportation						
2	Expected Volumes				219,500		
3	Indexed Gas Cost					6.5910	1,446,725
4	Base Commodity					0.0213	4,675
5	GRI	10				-	0
6	ACA	10				0.0016	351
7	Fuel and Loss Retention	10	0.13%			0.0086	1,888
8						6.6225	1,453,639
9							
10							

Non-Commodity

Line No.	Description		(1) Tariff Sheet No.	(2) Annual Units MMbtu	(3) Rate $/MMbtu	(4) Non-Commodity Total $	(5) Non-Commodity Demand $	(6) Transition Costs $
11	FT-G Contract #	014573		87,475				
12	Discount Rate on MDQs				7 2000	629,820	629,820	
13								
14				92,125				
15	GRI Surcharge		10			0	-	
16								
17	Reservation Fee					-	-	
18								
19	Total Trunkline Area Non-Commodity					629,820	629,820	
20								
21								

Atmos Energy Corporation
Demand Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Total Demand Cost:						
2	Texas Gas	$16,720,559					
3	Midwestern	0					
4	Tennessee Gas	2,925,726					
5	Trunkline	629,820					
6	Total	$20,276,105					
7							
8			Allocated	Related	Monthly Demand Charge		
9	Demand Cost Allocation:	Factors	Demand	Volumes	Firm	Interruptible	HLF
10	All	0.1850	$3,751,079	20,401,274	0.1839	0.1839	0.1839
11	Firm	0.8150	16,525,026	18,923,274	0.8733	NA	NA
12	Total	1.0000	$20,276,105		1.0572	0.1839	0.1839
13							
14			Volumetric Basis for				
15		Annualized	Monthly Demand Charge				
16		Mcf @14.65	All	Firm			
17	Firm Service						
18	Sales:						
19	G-1	18,887,274	18,887,274	18,887,274	1.0572		
20	HLF	60,000	60,000		0.1839 + HLF MDQ Demand		
21	LVS-1	0	0	0	1.0572		
22	Total Firm Sales	18,947,274	18,947,274	18,887,274			
23							
24	Transportation:						
25	T-2 \ G-1	36,000	36,000	36,000	1.0572		
26	HLF	0	0		0.1839		
27	Total Firm Service	18,983,274	18,983,274	18,923,274			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	684,000	684,000		1.0572	0.1839	
32	LVS-2	154,000	154,000		1.0572	0.1839	
33	Total Sales	838,000	838,000				
34							
35	Transportation:						
36	T-2 \ G-2	580,000	580,000		1.0572	0.1839	
37							
38	Total Interruptible Service	1,418,000	1,418,000				
39							
40	Carriage Service						
41	T-3 & T-4	23,438,000					
42							
43	Total	43,839,274	20,401,274	18,923,274			
44							
45	HLF MDQ Demand						
46	Firm Demand Cost		$16,525,026				
47	Peak Day Thru-put		302,152	Mcf/Peak Day			
48	Times:		12	Months/Year			
49	Total Annualized Peak Day Demand		3,625,824				
50	Demand Charge per MDQ		$4.5576	/ MDQ of Customer's Contract			
51							
52							
53	Note: LVS Credit =	($28,321)					

Atmos Energy Corporation
Take-or-Pay and Transition Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Other Fixed Charges	Take-or-Pay	Transition				
2	Texas Gas		$0				
3	Tennessee Gas		0				
4	Total	$0	$0				
5							
6							
7			Related	Charge			
8	Other Fixed Charges	Amount	Volumes	$/Mcf			
9	Take-or-Pay	0	43,839,274	0.0000			
10	Transition	0	20,401,274	0.0000			
11	Total	$0		0.0000			
12							
13							
14			Volumetric Basis for				
15		Annual	Other Fixed Charges			Other Fixed Charges	
16		Expected Mcf	Take-or-Pay	Transition		Take-or-Pay	Transition
17	Firm Service						
18	Sales:						
19	G-1	18,887,274	18,887,274	18,887,274			0.0000
20	HLF	60,000	60,000	60,000			0.0000
21	LVS-1	0	0	0			0.0000
22	Total Firm Sales	18,947,274	18,947,274	18,947,274			
23							
24	Transportation:						
25	T-2 \ G-1	36,000	36,000	36,000			0.0000
26	T-2 \ G-1 \ HLF	0					0.0000
27	Total Firm Service	18,983,274	18,983,274	18,983,274			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	684,000	684,000	684,000			0.0000
32	LVS-2	154,000	154,000	154,000			0.0000
33	Total Sales	838,000	838,000	838,000			
34							
35	Transportation:						
36	T-2 \ G-2	580,000	580,000	580,000			0.0000
37							
38	Total Interruptible Service	1,418,000	1,418,000	1,418,000			
39							
40	Carriage Service						
41	T-3 & T-4	23,438,000	23,438,000	NA			
42							
43	Total	43,839,274	43,839,274	20,401,274			
44							
45							
46	Note: LVS Credit =	$0					
47							

Atmos Energy Corporation
Expected Gas Cost - Commodity
Total System

Line No.	Description	(1) Purchases Mcf	(2) MMbtu	(3) Rate $/MMbtu	(4) Total $
1	**Texas Gas Area**				
2	No Notice Service	0	0	0.0000	0
3	Firm Transportation	88,780	91,000	6.7525	614,478
4	No Notice Storage	332,372	340,681	6.8574	2,336,185
5	Total Texas Gas Area	421,152	431,681	6.8353	2,950,663
6					
7	**Tennessee Gas Area**				
8	FT-A and FT-G	634,303	659,675	6.9659	4,595,229
9	FT-GS	115,808	120,440	7.4717	899,892
10	Gas Storage				
11	FT-A and FT-G Injections	207,101	215,385	6.6491	1,432,117
12	FT-GS Withdrawals	0	0	0.0000	0
13		957,212	995,500	6.9586	6,927,238
14	**Trunkline Gas Area**				
15	Firm Transportation	212,077	219,500	6.6225	1,453,639
16					
17					
18	**WKG System Storage**				
19	Injections	(759,591)	(778,581)	6.4373	(5,011,948)
20	Withdrawals	3,680,000	3,772,000	7.1670	27,033,924
21	Net WKG Storage	2,920,409	2,993,419	7.3568	22,021,976
22					
23					
24	Local Production	59,512	61,000	6.7525	411,903
25					
26					
27					
28	Total Commodity Purchases	4,570,362	4,701,100	7.1825	33,765,419
29					
30	Lost & Unaccounted for @ 1.38%	63,071	64,875		
31					
32	Total Deliveries	4,507,291	4,636,225	7.2830	33,765,419
33					
34	*LVS Commodity Credit to System*				
35	LVS Sales	(20,000)	(20,572)	9.4164	(193,714)
36					
37					
38	Total Expected Commodity Cost	4,487,291	4,615,653	7.2734	33,571,705
39					
40	Expected Commodity Cost ($/Mcf)			7.4815	
41					
42					
43					

Atmos Energy Corporation
Load Factor Calculation for Demand Allocation

Line No.	Description	MCF	
	Annualized Volumes Subject to Demand Charges		
1	Sales Volume	19,631,274	
2	Large Volume Sales (Annualized)	154,000	
3	Transportation	616,000	
4	Total Mcf Billed Demand Charges	20,401,274	
5	Divided by: Days/Year	365	
7	Average Daily Sales and Transport Volumes	55,894	
8			
10	Peak Day Sales and Transportation Volume		
11	Estimated total company firm requirements for 5 degree average		
12	temperature day from Peak Day Book - with adjustments per rate filing	302,152	Mcf/Peak Day
13			
14			
15	New Load Factor (line 7 / line 12)	**0.1850**	

Texas Gas T[illegible]mission LLP

Eighth Revised Sheet No. 20 : Effective

Superseding: Substitute Seventh Revised Sheet No. 20

Currently Effective Maximum Transportation Rates ($ per MMBtu)
For Service Under Rate Schedule NNS

	Base Tariff Rates (1)	FERC ACA (2)	Currently Effective Rates (3)
Zone SL			
Daily Demand	0.1800		0.1800
Commodity	0.0253	0.0016	0.0269
Overrun	0.2053	0.0016	0.2069
Zone 1			
Daily Demand	0.2782		0.2782
Commodity	0.0431	0.0016	0.0447
Overrun	0.3213	0.0016	0.3229
Zone 2			
Daily Demand	0.3088		0.3088
Commodity	0.0460	0.0016	0.0476
Overrun	0.3548	0.0016	0.3564
Zone 3			
Daily Demand	0.3543		0.3543
Commodity	0.0490	0.0016	0.0506
Overrun	0.4033	0.0016	0.4049
Zone 4			
Daily Demand	0.4190		0.4190
Commodity	0.0614	0.0016	0.0630
Overrun	0.4804	0.0016	0.4820

Minimum Rate: Demand $-0-; Commodity -

Zone SL	0.0163
Zone 1	0.0186
Zone 2	0.0223
Zone 3	0.0262
Zone 4	0.0308

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental transportation charge of:

Daily Demand	$0.0621
Commodity	$0.0155
Overrun	$0.0776

This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Substitute Fifth Revised Sheet No. 24 : Effective

Superseding: Second Sub Fourth Rev Sheet No. 24

Currently Effective Maximum Daily Demand Rates ($ per MMBtu)
For Service Under Rate Schedule FT

	Currently Effective Rates [1]
SL-SL	0.0794
SL-1	0.1552
SL-2	0.2120
SL-3	0.2494
SL-4	0.3142
1-1	0.1252
1-2	0.1820
1-3	0.2194
1-4	0.2842
2-2	0.1332
2-3	0.1705
2-4	0.2334
3-3	0.1181
3-4	0.1810
4-4	0.1374

Minimum Rates: Demand $-0-

Backhaul rates equal fronthaul rates to zone of delivery.

[1] Currently Effective Rates are equal to the Base Tariff Rates.

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental Daily Demand charge of $0.0621. This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Seventh Revised Sheet No. 25 : Effective

Superseding: Substitute Sixth Revised Sheet No. 25

Currently Effective Maximum Commodity Rates ($ per MMBtu)
For Service Under Rate Schedule FT

	Base Tariff Rates (1)	FERC ACA (2)	Currently Effective Rates (3)
SL-SL	0.0104	0.0016	0.0120
SL-1	0.0355	0.0016	0.0371
SL-2	0.0399	0.0016	0.0415
SL-3	0.0445	0.0016	0.0461
SL-4	0.0528	0.0016	0.0544
1-1	0.0337	0.0016	0.0353
1-2	0.0385	0.0016	0.0401
1-3	0.0422	0.0016	0.0438
1-4	0.0508	0.0016	0.0524
2-2	0.0323	0.0016	0.0339
2-3	0.0360	0.0016	0.0376
2-4	0.0446	0.0016	0.0462
3-3	0.0312	0.0016	0.0328
3-4	0.0398	0.0016	0.0414
4-4	0.0360	0.0016	0.0376

Minimum Rates: Commodity minimum base rates are presented on Sheet 31.

Backhaul rates equal fronthaul rates to zone of delivery.

Note: For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental Commodity charge of $0.0155. This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Texas Gas Transmission LLP

Substitute Fifth Revised Sheet No. 36 : Effective

Superseding: Sub 1 Rev 3 Rev Sheet No. 36

Schedule of Currently Effective Fuel Retention Percentages
Pursuant to Section 16 of the General Terms and Conditions

NNS/SGT/SNS RATE SCHEDULES

NNS/SGT WINTER

Delivery Zone	PFRP{1}	FAP{2}	EFRP{3}
SL	0.55%	(0.54%)	0.01%
1	2.33%	0.16%	2.49%
2	2.72%	(0.02%)	2.70%
3	2.79%	0.38%	3.17%
4	4.08%	(0.12%)	3.96%

NNS/SGT/SNS SUMMER

Delivery Zone	PFRP{1}	FAP{2}	EFRP{3}
SL	2.34%	(0.34%)	2.00%
1	1.97%	0.21%	2.18%
2	2.17%	0.19%	2.36%
3	2.25%	0.98%	3.23%
4	2.74%	0.26%	3.00%

FT/STF/IT RATE SCHEDULES

WINTER

Rec/Del Zone	PFRP	FAP	EFRP
SL or 1/SL	0.22%	0.71%	0.93%
SL or 1/1	1.33%	0.13%	1.46%
SL or 1/2	1.63%	(0.07%)	1.56%
SL or 1/3	1.80%	(0.07%)	1.73%
SL or 1/4	2.54%	(0.05%)	2.49%
2/2	0.33%	(0.23%)	0.10%
2/3	0.56%	0.57%	1.13%
2/4	1.29%	(0.50%)	0.79%
3/3	0.26%	(0.15%)	0.11%
3/4	0.99%	0.19%	1.18%
4/4	0.76%	0.32%	1.08%

SUMMER

Rec/Del Zone	PFRP	FAP	EFRP
SL or 1/SL	0.22%	0.75%	0.97%
SL or 1/1	1.48%	(0.01%)	1.47%
SL or 1/2	1.91%	(0.04%)	1.87%
SL or 1/3	1.92%	0.09%	2.01%
SL or 1/4	2.44%	(0.22%)	2.22%
2/2	0.45%	(0.45%)	0.00%
2/3	0.57%	1.93%	2.50%
2/4	1.06%	(1.06%)	0.00%
3/3	0.13%	(0.12%)	0.01%
3/4	0.63%	(0.09%)	0.54%
4/4	0.52%	0.19%	0.71%

FSS/ISS RATE SCHEDULES

Withdrawal

PFRP	FAP	EFRP
1.00%	0.23%	1.23%

Injection

PFRP	FAP	EFRP
0.80%	0.39%	1.19%

{1} Projected Fuel Retention Percentage
{2} Fuel Adjustment Percentage
{3} Effective Fuel Retention Percentage

Thirty-Fourth Revised Sheet No. 20 : Effective

Superseding: Thirty-Third Revised Sheet No. 20.

RATES PER DEKATHERM

FIRM TRANSPORTATION - GS RATES (FT-GS)

Base Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.2138		$0.4203	$0.5844	$0.6748	$0.7814	$0.8952	$1.0698
L		$0.1771						
1	$0.4318		$0.3268	$0.4951	$0.5849	$0.6915	$0.8052	$0.9804
2	$0.5844		$0.4951	$0.2000	$0.2897	$0.4144	$0.5106	$0.6852
3	$0.6748		$0.5849	$0.2897	$0.1489	$0.3995	$0.4951	$0.6698
4	$0.7995		$0.7096	$0.4144	$0.3995	$0.1886	$0.2311	$0.4061
5	$0.8952		$0.8052	$0.5106	$0.4951	$0.2311	$0.1989	$0.3466
6	$1.0698		$0.9804	$0.6852	$0.6698	$0.4061	$0.3466	$0.2374

Surcharges

PCB Adjustment: 1/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
L		$0.0000						
1	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
3	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
4	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
5	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
6	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Annual Charge Adjustment (ACA): $0.0016

Maximum Rates 2/, 3/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.2154		$0.4219	$0.5860	$0.6764	$0.7830	$0.8968	$1.0714
L		$0.1787						
1	$0.4334		$0.3284	$0.4967	$0.5865	$0.6931	$0.8068	$0.9820
2	$0.5860		$0.4967	$0.2016	$0.2913	$0.4160	$0.5122	$0.6868
3	$0.6764		$0.5865	$0.2913	$0.1505	$0.4011	$0.4967	$0.6714
4	$0.8011		$0.7112	$0.4160	$0.4011	$0.1902	$0.2327	$0.4077
5	$0.8968		$0.8068	$0.5122	$0.4967	$0.2327	$0.2005	$0.3482
6	$1.0714		$0.9820	$0.6868	$0.6714	$0.4077	$0.3482	$0.2390

Minimum Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Notes:

1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2008 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

3/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Eighteenth Revised Sheet No. 23A : Effective

Superseding: Seventeenth Revised Sheet No. 23A

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0455		$0.0685	$0.0896	$0.0994	$0.1134	$0.1247	$0.1624
L		$0.0302						
1	$0.0685		$0.0588	$0.0792	$0.0890	$0.1030	$0.1142	$0.1519
2	$0.0896		$0.0792	$0.0449	$0.0546	$0.0697	$0.0799	$0.1175

Tennessee Gas Pipeline

3	$0.0994	$0.0890	$0.0546	$0.0382	$0.0679	$0.0781	$0.1158
4	$0.1145	$0.1041	$0.0697	$0.0679	$0.0417	$0.0475	$0.0850
5	$0.1247	$0.1142	$0.0799	$0.0781	$0.0475	$0.0443	$0.0781
6	$0.1624	$0.1519	$0.1175	$0.1158	$0.0850	$0.0781	$0.0658

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0016

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Fifteenth Revised Sheet No. 23B : Effective

Superseding: Fourteenth Revised Sheet No. 23B

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-G

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
L		$0.00						
1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14

4	$12.53	$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09	$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59	$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-G Reservation Rate is $0.00 per Dth

Notes:
1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2008 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
2/ Maximum rates are inclusive of base rates and above surcharges.

Sixteenth Revised Sheet No. 23C : Effective

Superseding: Fifteenth Revised Sheet No. 23C

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-G

Base Commodity Rate

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0455		$0.0685	$0.0896	$0.0994	$0.1134	$0.1247	$0.1624
L		$0.0302						
1	$0.0685		$0.0588	$0.0792	$0.0890	$0.1030	$0.1142	$0.1519
2	$0.0896		$0.0792	$0.0449	$0.0546	$0.0697	$0.0799	$0.1175

Tennessee Gas Pipeline

3	$0.0994	$0.0890	$0.0546	$0.0382	$0.0679	$0.0781	$0.1158
4	$0.1145	$0.1041	$0.0697	$0.0679	$0.0417	$0.0475	$0.0850
5	$0.1247	$0.1142	$0.0799	$0.0781	$0.0475	$0.0443	$0.0781
6	$0.1624	$0.1519	$0.1175	$0.1158	$0.0850	$0.0781	$0.0658

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0016

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.
solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Sixteenth Revised Sheet No. 27 : Effective

Superseding: Fifteenth Revised Sheet No. 27

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (TCSM)	ADJUSTMENTS (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA						
Deliverability Rate	$2.02			$0.00	$2.02	
Space Rate	$0.0248			$0.0000	$0.0248	1.49%
Injection Rate	$0.0053				$0.0053	
Withdrawal Rate	$0.0053				$0.0053	
Overrun Rate	$0.2427				$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA						
Deliverability Rate	$1.15			$0.00	$1.15	
Space Rate	$0.0185			$0.0000	$0.0185	1.49%
Injection Rate	$0.0102				$0.0102	
Withdrawal Rate	$0.0102				$0.0102	
Overrun Rate	$0.1380				$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA						
Space Rate	$0.0848			$0.0000	$0.0848	1.49%
Injection Rate	$0.0102				$0.0102	
Withdrawal Rate	$0.0102				$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA						
Space Rate	$0.0993			$0.0000	$0.0993	1.49%
Injection Rate	$0.0053				$0.0053	
Withdrawal Rate	$0.0053				$0.0053	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2008 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

Excess Withdrawal Rate	$0.7800	$0.0019		$0.7819	
SS-NE					

Deliverability	$6.71		$0.00	$6.71	
Space Rate	$0.0132		$0.0000	$0.0132	
Injection Rate	$0.0102			$0.0102	3.25%
Withdrawal Rate	$0.0936			$0.0936	
Excess Withdrawal Rate	$1.1600	$0.0019		$1.1619	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

First Revised Sheet No. 29 : Effective
Superseding: Substitute Original Sheet No. 29

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\, 3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interuptible Transportation-X, (FT-G) Firm Transportation-G, (EDS/ERS) FT- A Extended Transportation Service.

Twelfth Revised Sheet No. 10 : Effective

Superseding: Eleventh Revised Sheet No. 10

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

	Base Rate Per Dt (1)	Adjustment Sec. 24 (2)	Maximum Rate Per Dt (3)	Minimum Rate Per Dt (4)	Fuel Reimbursement (5)
RATE SCHEDULE FT					
Field Zone to Zone 2					
- Reservation Rate	$ 9.7097	-	$ 9.7097	-	-
- Usage Rate (1)	0.0141	-	0.0141	$ 0.0141	1.55 % (2)
- Overrun Rate (3)	0.3192	-	0.3192	-	-
Zone 1A to Zone 2					
- Reservation Rate	$ 6.0096	-	$ 6.0096	-	-
- Usage Rate (1)	0.0117	-	0.0117	$ 0.0117	1.21 % (2)
- Overrun Rate (3)	0.1976	-	0.1976	-	-
Zone 1B to Zone 2					
- Reservation Rate	$ 4.5557	-	$ 4.5557	-	-
- Usage Rate (1)	0.0062	-	0.0062	$ 0.0062	0.32 % (2)
- Overrun Rate (3)	0.1498	-	0.1498	-	-
Zone 2 Only					
- Reservation Rate	$ 3.4350	-	$ 3.4350	-	-
- Usage Rate (1)	0.0011	-	0.0011	$ 0.0011	0.05 % (2)
- Overrun Rate (3)	0.1129	-	0.1129	-	-
Field Zone to Zone 1B					
- Reservation Rate	$ 8.4890	-	$ 8.4890	-	-
- Usage Rate (1)	0.0130	-	0.0130	$ 0.0130	1.36 % (2)
- Overrun Rate (3)	0.2791	-	0.2791	-	-
Zone 1A to Zone 1B					
- Reservation Rate	$ 4.7889	-	$ 4.7889	-	-
- Usage Rate (1)	0.0106	-	0.0106	$ 0.0106	1.02 % (2)
- Overrun Rate (3)	0.1574	-	0.1574	-	-
Zone 1B Only					
- Reservation Rate	$ 3.3350	-	$ 3.3350	-	-
- Usage Rate (1)	0.0051	-	0.0051	$ 0.0051	0.13 % (2)
- Overrun Rate (3)	0.1096	-	0.1096	-	-
Field Zone to Zone 1A					
- Reservation Rate	$ 7.3683	-	$ 7.3683	-	-
- Usage Rate (1)	0.0079	-	0.0079	$ 0.0079	1.09 % (2)
- Overrun Rate (3)	0.2422	-	0.2422	-	-
Zone 1A Only					

Trunkline

- Reservation Rate	$ 3.6682	-	$ 3.6682	-	-
- Usage Rate (1)	0.0055	-	0.0055	$ 0.0055	0.75 % (2)
- Overrun Rate (3)	0.1206	-	0.1206	-	-
Field Zone Only					
- Reservation Rate	$ 3.7001	-	$ 3.7001	-	-
- Usage Rate (1)	0.0024	-	0.0024	$ 0.0024	0.20 % (2)
- Overrun Rate (3)	0.1216	-	0.1216	-	-
Gathering Charge (All Zones)					
- Reservation Rate	$ 0.3257		$ 0.3257		
- Overrun Rate (3)	0.0107		0.0107		

(1) Excludes Section 21 Annual Charge Adjustment: $0.0016
(2) Fuel reimbursement for backhauls is 0.31%
(3) Maximum firm volumetric rate applicable for capacity release
(1) Excludes Section 21 Annual Charge Adjustment: $0.0018
(2) Fuel reimbursement for backhauls is 0.41%
(3) Maximum firm volumetric rate applicable for capacity release

Atmos Energy Corporation
Basis for Indexed Gas Cost
For the Quarter of February 2007 - April 2007
2006-00000

The projected commodity price was provided by the Gas Supply Department and was based upon the following:

A. The Gas Supply Department reviewed the NYMEX futures close prices for the quarter of February 2007 - April 2007 during the period December 20, 2006 through December 29, 2006 which are listed below:

		Feb-07 ($/MMBTU)	Mar-07 ($/MMBTU)	Apr-07 ($/MMBTU)
Wednesday	12/20/06	6.949	7.014	7.034
Thursday	12/21/06	6.980	7.063	7.096
Friday	12/22/06	6.810	6.880	6.925
Tuesday	12/26/06	6.333	6.418	6.508
Wednesday	12/27/06	6.142	6.257	6.357
Thursday	12/28/06	6.248	6.392	6.482
Friday	12/29/06	6.299	6.503	6.603
		$6.537	$6.647	$6.715

B. Gas Supply believes prices will remain stable and prices for the quarter of Feb 2007 - Apri 2007 will settle at 6.591 per Mmbtu for the period that the GCA is to be effective.

In support of Item B, a worksheet entitled "Estimated Weighted Average Cost of Gas" has been filed under a Petition for Confidentiality in this Case.

Atmos Energy Corporation
Kentucky Division
For the Month of November, 2006

For Kentucky customers served in:		Indexed 1 Cash-out Price		Transport Charge 2, 3		WKG Cash-out Price
A. Texas Gas:						
Zone 2 Area	100% of Index Price	$7.3880	+	$0.0476	=	$7.4356
	90% of Index Price	6.6492	+	0.0476	=	6.6968
	80% of Index Price	5.9104	+	0.0476	=	5.9580
Zone 3 Area	100% of Index Price	$7.3880	+	$0.0506	=	$7.4386
	90% of Index Price	6.6492	+	0.0506	=	6.6998
	80% of Index Price	5.9104	+	0.0506	=	5.9610
Zone 4 Area	100% of Index Price	$7.3880	+	$0.0630	=	$7.4510
	90% of Index Price	6.6492	+	0.0630	=	6.7122
	80% of Index Price	5.9104	+	0.0630	=	5.9734
B. Tennessee Gas:						
Zone 2 Area	100% of Index Price	$6.8875	+	$0.0880	=	$6.9755
	90% of Index Price	6.1988	+	0.0880	=	6.2868
	80% of Index Price	5.5100	+	0.0880	=	5.5980

[1] Indexed cash-out price is from the pipeline's Electronic Bulletin Board.

[2] Transport charge used for Texas Gas is its tariff sheet no. 20 commodity rate.

[3] Transport charge used for Tennessee Gas is its tariff sheet no. 23A maximum commodity rate from zone 0 to zone 2.

Atmos Energy Corporation
Estimated Weighted Average Cost of Gas
February-07 Through April-07

	February-07			March-07			April-07			Total		
	Volumes	Rate	Value	Volumes	Rate	Value	Volumes	Rate	Value	Volumes	Rate	Value
Texas Gas												
Trunkline												
Tennessee Gas												
TX Gas Storage												
TN Gas Storage												
WKG Storage												
Midwestern												
WACOGs												

(This information has been filed under a Petition for Confidentiality)

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
JAN 11 2007
PUBLIC SERVICE COMMISSION

In the Matter of:

REVISED GAS COST ADJUSTMENT FILING OF ATMOS ENERGY CORPORATION	)))	**CASE NO. 2006 - 00568**

PETITION FOR CONFIDENTIALITY OF INFORMATION BEING FILED WITH THE KENTUCKY PUBLIC SERVICE COMMISSION

Atmos Energy Corporation ("Atmos") respectfully petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001 Section 7 and all other applicable law, for confidential treatment of the information which is described below and which is attached hereto. In support of this Petition, Atmos states as follows:

1. Atmos is filing its Gas Cost Adjustment ("GCA") for the quarterly period commencing on February 1, 2007. This GCA filing also contains Atmos' quarterly Correction Factor (CF) as well as information pertaining to Atmos' projected gas prices. The following attachment contains information which requires confidential treatment:

> The attached Weighted Average Cost of Gas ("WACOG") schedule in support of Exhibit C, page 19 contains confidential information pertaining to prices projected to be paid by Atmos for purchase contracts.

2. Information of the type described above has previously been filed by Atmos with the Commission under petitions for confidentiality. Exhibit D contains information from which it

could be determined what Atmos is paying for natural gas under its gas supply agreement with its existing supplier. The Commission has consistently granted confidential protection to that type of information in each of the prior GCA filings in KPSC Case No. 1999-070. The information contained in the attached WACOG schedule has also been filed with the Commission under a Petition for Confidentiality in Case No. 97-513.

3. All of the information sought to be protected herein as confidential, if publicly disclosed, would have serious adverse consequences to Atmos and its customers. Public disclosure of this information would impose an unfair commercial disadvantage on Atmos. Atmos has successfully negotiated an extremely advantageous gas supply contract that is very beneficial to Atmos and its ratepayers. Detailed information concerning that contract, including commodity costs, demand and transportation charges, reservations fees, etc. on specifically identified pipelines, if made available to Atmos' competitors, (including specifically non-regulated gas marketers), would clearly put Atmos to an unfair commercial disadvantage. Those competitors for gas supply would be able to gain information that is otherwise confidential about Atmos' gas purchases and transportation costs and strategies. The Commission has accordingly granted confidential protection to such information.

4. Likewise, the information contained in the WACOG schedule in support of Exhibit C, page 19, also constitutes sensitive, proprietary information which if publicly disclosed would put Atmos to an unfair commercial disadvantage in future negotiations.

5. Atmos would not, as a matter of company policy, disclose any of the information for which confidential protection is sought herein to any person or entity, except as required by law or pursuant to a court order or subpoena. Atmos' internal practices and policies are directed towards non-disclosure of the attached information. In fact, the information contained in the

attached report is not disclosed to any personnel of Atmos except those who need to know in order to discharge their responsibility. Atmos has never disclosed such information publicly. This information is not customarily disclosed to the public and is generally recognized as confidential and proprietary in the industry.

6. There is no significant interest in public disclosure of the attached information. Any public interest in favor of disclosure of the information is out weighed by the competitive interest in keeping the information confidential.

7. The attached information is also entitled to confidential treatment because it constitutes a trade secret under the two prong test of KRS 265.880: (a) the economic value of the information as derived by not being readily ascertainable by other persons who might obtain economic value by its disclosure; and, (b) the information is the subject of efforts that are reasonable under the circumstances to maintain its secrecy. The economic value of the information is derived by Atmos maintaining the confidentiality of the information since competitors and entities with whom Atmos transacts business could obtain economic value by its disclosure.

8. Pursuant to 807 KAR 5:001 Section 7(3) temporary confidentiality of the attached information should be maintained until the Commission enters an order as to this petition. Once the order regarding confidentiality has been issued, Atmos would have twenty (20) days to seek alternative remedies pursuant to 807 KAR 5:001 Section 7(4).

WHEREFORE, Atmos petitions the Commission to treat as confidential all of the material and information which is included in the attached one volume marked "Confidential".

Respectfully submitted this ~~22nd day of December, 2006.~~
9TH Day of January, 2007.

Mark R. Hutchinson
611 Frederica Street
Owensboro, Kentucky 42301

Douglas Walther
Atmos Energy Corporation
P.O. Box 650250
Dallas, Texas 75265

John N. Hughes
124 W. Todd Street
Frankfort, Kentucky 40601

Attorneys for Atmos Energy Corporation

RECEIVED
MAR 30 2006
PUBLIC SERVICE COMMISSION

March 29, 2006

Ms. Elizabeth O'Donnell, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602

Re: Case No. 2006-000135

Dear Ms. O'Donnell:

We are filing the enclosed original and three (3) copies of a notice under the provisions of our Gas Cost Adjustment Clause, Case No. 2006-00135. **This filing contains a Petition of Confidentiality and confidential documents.**

Please indicate receipt of this filing by stamping and dating the enclosed duplicate of this letter and returning it in the self-addressed stamped envelope to the following address:

Atmos Energy Corporation
5430 LBJ Freeway, Suite 600
Dallas, TX 75240

If you have any questions, feel free to call me at 972-855-3011.

Sincerely,

Thomas J. Morel

Thomas J. Morel
Senior Rate Analyst, Rate Administration

Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED

MAR 30 2006

PUBLIC SERVICE
COMMISSION

In the Matter of:

GAS COST ADJUSTMENT	)	Case No. 2006 - 00135
FILING OF	)	
ATMOS ENERGY CORPORATION	)	

NOTICE

QUARTERLY FILING

For The Period

May 1, 2006 - July 31, 2006

Attorney for Applicant

Mark R. Hutchinson
1700 Frederica St.
Suite 201
Owensboro, Kentucky 42301

March 29, 2006

Atmos Energy Corporation, ("the Company"), is duly qualified under the laws of the Commonwealth of Kentucky to do its business. The Company is an operating public utility engaged in the business of purchasing, transporting and distributing natural gas to residential, commercial and industrial users in western and central Kentucky. The Company's principal operating office and place of business is 2401 New Hartford Road, Owensboro, Kentucky 42301. Correspondence and communications with respect to this notice should be directed to:

Gary L. Smith
Vice President - Marketing &
Regulatory Affairs/Kentucky Division
Atmos Energy Corporation
Post Office Box 866
Owensboro, Kentucky 42302

Mark R. Hutchinson
Attorney for Applicant
1700 Frederica St.
Suite 201
Owensboro, Kentucky 42301

Thomas J. Morel
Senior Rate Analyst, Rate Administration
Atmos Energy Corporation
5430 LBJ Freeway, Suite 600
Dallas, Texas 75240

The Company gives notice to the Kentucky Public Service Commission, hereinafter "the Commission", pursuant to the Gas Cost Adjustment Clause contained in the Company's settlement gas rate schedules in Case No. 99-070.

The Company hereby files Seventeenth Revised Sheet No. 4, Seventeenth Revised Sheet No. 5 and Seventeenth Revised Sheet No. 6 to its PSC No. 1, Rates, Rules and Regulations for Furnishing Natural Gas to become effective May 1, 2006.

The Gas Cost Adjustment (GCA) for firm sales service is $9.3487 per Mcf, $8.4754 per Mcf for high load factor firm sales service, and $8.4754 per Mcf for interruptible sales service. The supporting calculations for the Seventeenth Revised Sheet No. 5 are provided in the following Exhibits:

Exhibit A - Summary of Derivations of Gas Cost Adjustment (GCA) ....
Exhibit B - Expected Gas Cost (EGC) Calculation ....
Exhibit C - Rates used in the Expected Gas Cost (EGC) Calculation .....
Exhibit D - Correction Factor (CF) Calculation ....
Exhibit E - Refund Certificate of Compliance ....
Exhibit F - LVS Pricing Calculation ....

Since the Company's last GCA filing, Case No. 2005-00552, the following changes have occurred in its pipeline and gas supply commodity rates for the GCA period.

1. The commodity rates per MMbtu used are based on historical estimates and/or current data for the quarter May 2006 through July 2006, as shown in Exhibit C, page 19.

2. The Expected Commodity Gas Cost will be approximately $7.9545 MMbtu for the quarter May 2006 through July 2006, as compared to $10.3019 per MMbtu used for the quarter of February 2006 through April 2006.

3. The Company's notice sets out a new Correction Factor of $0.2988 per Mcf, which will remain in effect until at least July 31, 2006.

The GCA tariff as approved in Case No. 92-558 provides for a Correction Factor (CF) which compensates for the difference between the expected gas cost and the actual gas cost for prior periods. A revision to the GCA tariff effective December 1, 2001, Filing No. T62-1253, provides that the Correction Factor be filed on a quarterly basis. The Company is filing its updated Correction Factor that is based upon the balance in the Company's Account 191 as of January 31, 2006. The calculation for the Correction Factor is shown on Exhibit D, Page 1.

WHEREFORE, Atmos Energy Corporation requests this Commission, pursuant to the Commission's order in Case No. 99-070, to approve the Gas Cost Adjustment (GCA) as filed in Seventeenth Revised Sheet No. 5; and Seventeenth Revised Sheet No. 6 setting out the General Transportation Tariff Rate T-2 for each respective sales rate for meter readings made on and after May 1, 2006.

DATED at Dallas Texas, this 29th Day of March, 2006.

ATMOS ENERGY CORPORATION

By: Thomas J. Morel

Thomas J. Morel
Senior Rate Analyst, Rate Administration
Atmos Energy Corporation

For Entire Service Area
P.S.C. No. 1
Seventeenth SHEET No. 4
Cancelling
Sixteenth SHEET No. 4

ATMOS ENERGY CORPORATION

Current Rate Summary

Case No. 2006-00000

Firm Service

Base Charge:

Residential	-	$7.50	per meter per month
Non-Residential	-	20.00	per meter per month
Carriage (T-4)	-	220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

Rate per Mcf[2]				Sales (G-1)			Transport (T-2)			Carriage (T-4)		
First	300 [1]	Mcf	@	10.5387	per Mcf	@	2.2472	per Mcf	@	1.1900	per Mcf	(R, R, N)
Next	14,700 [1]	Mcf	@	10.0077	per Mcf	@	1.7162	per Mcf	@	0.6590	per Mcf	(R, R, N)
Over	15,000	Mcf	@	9.7787	per Mcf	@	1.4872	per Mcf	@	0.4300	per Mcf	(R, R, N)

High Load Factor Firm Service

HLF demand charge/Mcf	@	4.5576	@	4.5576 per Mcf of daily Contract Demand	(R)

Rate per Mcf[2]									
First	300 [1]	Mcf	@	9.6654	per Mcf	@	1.3739	per Mcf	(R, R)
Next	14,700 [1]	Mcf	@	9.1344	per Mcf	@	0.8429	per Mcf	(R, R)
Over	15,000	Mcf	@	8.9054	per Mcf	@	0.6139	per Mcf	(R, R)

Interruptible Service

Base Charge	-	$220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

Rate per Mcf[2]				Sales (G-2)			Transport (T-2)			Carriage (T-3)		
First	15,000 [1]	Mcf	@	9.0470	per Mcf	@	0.7139	per Mcf	@	0.5300	per Mcf	(R, R, N)
Over	15,000	Mcf	@	8.8761	per Mcf	@	0.5430	per Mcf	@	0.3591	per Mcf	(R, R, N)

[1] All gas consumed by the customer (sales, transportation, and carriage; firm, high load factor, and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] DSM, GRI and MLR Riders may also apply, where applicable.

ISSUED: March 29, 2006 **Effective:** May 1, 2006

(Issued by Authority of an Order of the Public Service Commission in Case No. 2006-00000.)

ISSUED BY: Gary L. Smith Vice President - Marketing & Regulatory Affairs/Kentucky Division

ATMOS ENERGY CORPORATION

Current Gas Cost Adjustments

Case No. 2006-00000

Applicable

For all Mcf billed under General Sales Service (G-1) and Interruptible Sales Service (G-2).

Gas Charge = GCA

GCA = EGC + CF + RF + PBRRF

Gas Cost Adjustment Components	G - 1	HLF G - 1	G-2	
EGC (Expected Gas Cost Component)	9.0117	8.1384	8.1384	(R, R, R)
CF (Correction Factor)	0.2988	0.2988	0.2988	(R, R, R)
RF (Refund Adjustment)	(0.0017)	(0.0017)	(0.0017)	(N, N, I)
PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0399	(N, N, N)
GCA (Gas Cost Adjustment)	$9.3487	$8.4754	$8.4754	(R, R, R)

ISSUED: March 29, 2006 Effective: May 1, 2006

(Issued by Authority of an Order of the Public Service Commission in Case No. 2006-00000.)

ISSUED BY: Gary L. Smith Vice President - Marketing & Regulatory Affairs/Kentucky Division

ATMOS ENERGY CORPORATION

Current Transportation and Carriage

Case No. 2006-00000

Case No. 2004-00398

The General Transportation Rate T-2 and Carriage Service (Rates T-3 and T-4) for each respective service net monthly rate is as follows:

System Lost and Unaccounted gas percentage: 1.38%

					Simple Margin		Non-Commodity		Gross Margin		
Transportation Service (T-2)[1]											
a)	Firm Service										
	First	300 [2]	Mcf	@	$1.1900	+	$1.0572	=	$2.2472	per Mcf	(R)
	Next	14,700 [2]	Mcf	@	0.6590	+	1.0572	=	1.7162	per Mcf	(R)
	All over	15,000	Mcf	@	0.4300	+	1.0572	=	1.4872	per Mcf	(R)
b)	High Load Factor Firm Service (HLF)										
	Demand			@	$0.0000	+	4.5576	=	$4.5576	per Mcf of daily contract demand	(R)
	First	300 [2]	Mcf	@	$1.1900	+	$0.1839	=	$1.3739	per Mcf	(R)
	Next	14,700 [2]	Mcf	@	0.6590	+	0.1839	=	0.8429	per Mcf	(R)
	All over	15,000	Mcf	@	0.4300	+	0.1839	=	0.6139	per Mcf	(R)
c)	Interruptible Service										
	First	15,000 [2]	Mcf	@	$0.5300	+	$0.1839	=	$0.7139	per Mcf	(R)
	All over	15,000	Mcf	@	0.3591	+	0.1839	=	0.5430	per Mcf	(R)
Carriage Service[3]											
	Firm Service (T-4)										
	First	300	[2] Mcf	@	$1.1900	+	$0.0000	=	$1.1900	per Mcf	(N)
	Next	14,700	[2] Mcf	@	0.6590	+	0.0000	=	0.6590	per Mcf	(N)
	All over	15,000	[2] Mcf	@	0.4300	+	0.0000	=	0.4300	per Mcf	(N)
	Interruptible Service (T-3)										
	First	15,000 [2]	Mcf	@	$0.5300	+	$0.0000	=	$0.5300	per Mcf	(N)
	All over	15,000	Mcf	@	0.3591	+	0.0000	=	0.3591	per Mcf	(N)

[1] Includes standby sales service under corresponding sales rates. GRI Rider may also apply.

[2] All gas consumed by the customer (Sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[3] Excludes standby sales service.

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Sales Service

Line No.	Description	Case No. 2005-00552 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	G-1			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 300 Mcf	1.1900	1.1900	0.0000
5	Next 14,700 Mcf	0.6590	0.6590	0.0000
6	Over 15,000 Mcf	0.4300	0.4300	0.0000
7				
8	Gas Cost Adjustment Components			
9	EGC (Expected Gas Cost):			
10	Commodity	10.3019	7.9545	(2.3474)
11	Demand	1.2622	1.0572	(0.2050)
12	Take-Or-Pay	0.0000	0.0000	0.0000
13	Transition Costs	0.0000	0.0000	0.0000
14	Total EGC	11.5641	9.0117	(2.5524)
15	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
16	CF (Correction Factor)	0.7717	0.2988	(0.4729)
17	RF (Refund Adjustment)	(0.0017)	(0.0017)	0.0000
18	PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0000
19	GCA (Gas Cost Adjustment)	12.3740	9.3487	(3.0253)
20	Total Billing Cost of Gas	12.3740	9.3487	(3.0253)
21				
22	Commodity Charge (GCA included):			
23	First 300 Mcf	13.5640	10.5387	(3.0253)
24	Next 14,700 Mcf	13.0330	10.0077	(3.0253)
25	Over 15,000 Mcf	12.8040	9.7787	(3.0253)
26				
27	**HLF (High Load Factor)**			
28				
29	Commodity Charge (Base Rate per Case No. 99-070):			
30	First 300 Mcf	1.1900	1.1900	0.0000
31	Next 14,700 Mcf	0.6590	0.6590	0.0000
32	Over 15,000 Mcf	0.4300	0.4300	0.0000
33				
34	Gas Cost Adjustment Components			
35	EGC (Expected Gas Cost):			
36	Commodity	10.3019	7.9545	(2.3474)
37	Demand	0.2195	0.1839	(0.0356)
38	Take-Or-Pay	0.0000	0.0000	0.0000
39	Transition Costs	0.0000	0.0000	0.0000
40	Total EGC	10.5214	8.1384	(2.3830)
41	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
42	CF (Correction Factor)	0.7717	0.2988	(0.4729)
43	RF (Refund Adjustment)	(0.0017)	(0.0017)	0.0000
44	PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0000
45	GCA (Gas Cost Adjustment)	11.3313	8.4754	(2.8559)
46	Total Cost of Gas to Bill (excludes MDQ Demand)	11.3313	8.4754	(2.8559)
47				
48	Commodity Charge (GCA included):			
49	First 300 Mcf	12.5213	9.6654	(2.8559)
50	Next 14,700 Mcf	11.9903	9.1344	(2.8559)
51	Over 15,000 Mcf	11.7613	8.9054	(2.8559)
52				
53	HLF Demand			
54	Contract Demand Factor	5.4418	4.5576	(0.8842)

Atmos Energy Corporation
Comparison of Current and Previous Cases
Interruptible Sales Service

Line No.	Description	Case No. 2005-00552 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	**G-2**			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 15,000 Mcf	0.5300	0.5300	0.0000
5	Over 15,000 Mcf	0.3591	0.3591	0.0000
6				
7	Gas Cost Adjustment Components			
8	Expected Gas Cost (EGC):			
9	Commodity	10.3019	7.9545	(2.3474)
10	Demand	0.2195	0.1839	(0.0356)
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0000	0.0000	0.0000
13	Total EGC	10.5214	8.1384	(2.3830)
14	Less: Base Cost of Gas (BCOG)	0.0000	0.0000	0.0000
15	Correction Factor (CF)	0.7717	0.2988	(0.4729)
16	Refund Adjustment (RF)	(0.0017)	(0.0017)	0.0000
17	Performance Based Rate Recovery Factor (PBRRF)	0.0399	0.0399	0.0000
18	Gas Cost Adjustment (GCA)	11.3313	8.4754	(2.8559)
19	Total Cost of Gas to Bill	11.3313	8.4754	(2.8559)
20				
21	Commodity Charge (GCA included):			
22	First 15,000 Mcf	11.8613	9.0054	(2.8559)
23	Over 15,000 Mcf	11.6904	8.8345	(2.8559)
24				
25				

Line No.		Case No.	Effective Date	G - 1	G - 1 / HLF	G - 2
26	Monthly Refund Factor					
29	1 -	1999-070 L	07/01/01	0.0000	0.0000	0.0000
30	2 -	1999-070 M	08/01/01	0.0000	0.0000	0.0000
31	3 -	1999-070 N	10/01/01	0.0000	0.0000	0.0000
32	4 -	1999-070 O	11/01/01	(0.0019)	(0.0019)	(0.0019)
33	5 -	1999-070 P	05/03/02	0.0000	0.0000	0.0000
34	6 -	2002-00251	08/01/02	(0.0095)	(0.0095)	(0.0019)
35	7 -	2002-00359	11/01/02	(0.1574)	(0.1574)	(0.0391)
36	8 -	2003-00377	11/01/03	(0.0006)	(0.0006)	(0.0006)
37	9 -	2004-00269	08/01/04	(0.0048)	(0.0048)	(0.0048)
38	10 -	2005-00399	11/01/05	(0.0017)	(0.0017)	(0.0017)
39	11 -					
40	12 -					
41						
42	Total Supplier Refund Adjustment (RF)			(0.0017)	(0.0017)	(0.0017)
43						

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description		Case No. 2005-00552 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	T-2 \ G-1				
2					
3					
4	Simple Margin (Base Rate per Case No. 99-070):				
5	First	300 Mcf	1.1900	1.1900	0.0000
6	Next	14,700 Mcf	0.6590	0.6590	0.0000
7	Over	15,000 Mcf	0.4300	0.4300	0.0000
8					
9	Non-Commodity Components:				
10	Demand		1.2622	1.0572	(0.2050)
11	Take-Or-Pay		0.0000	0.0000	0.0000
12	Transition Costs		0.0000	0.0000	0.0000
13	RF (Refund Adjustment)		0.0000	0.0000	0.0000
14	Total		1.2622	1.0572	(0.2050)
15					
16	Gross Margin:				
17	First	300 Mcf	2.4522	2.2472	(0.2050)
18	Next	14,700 Mcf	1.9212	1.7162	(0.2050)
19	Over	15,000 Mcf	1.6922	1.4872	(0.2050)
20					
21	T-2\G-1\HLF				
22					
23	Simple Margin (Base Rate per Case No. 99-070):				
24	First	300 Mcf	1.1900	1.1900	0.0000
25	Next	14,700 Mcf	0.6590	0.6590	0.0000
26	Over	15,000 Mcf	0.4300	0.4300	0.0000
27					
28	Non-Commodity Components:				
29	Demand		0.2195	0.1839	(0.0356)
30	Take-Or-Pay		0.0000	0.0000	0.0000
31	Transition Costs		0.0000	0.0000	0.0000
32	RF (Refund Adjustment)		0.0000	0.0000	0.0000
33	Total		0.2195	0.1839	(0.0356)
34					
35	Gross Margin (Excluding HLF Demand):				
36	First	300 Mcf	1.4095	1.3739	(0.0356)
37	Next	14,700 Mcf	0.8785	0.8429	(0.0356)
38	Over	15,000 Mcf	0.6495	0.6139	(0.0356)
39					
40	HLF Demand				
41	Contract Demand Factor		4.6207	4.5576	(0.0631)
42					

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description			Case No. 2005-00552	Case No. 2006-00000	Difference
				$/Mcf	$/Mcf	$/Mcf
1	**Carriage Service**					
2						
3	Firm Service (T-4)					
4	Simple Margin (Base Rate per Case No. 99-070):					
5	First	300	Mcf	1.1900	1.1900	0.0000
6	Next	14,700	Mcf	0.6590	0.6590	0.0000
7	Over	15,000	Mcf	0.4300	0.4300	0.0000
8						
9	Non-Commodity Components:					
11	Take-Or-Pay			0.0000	0.0000	0.0000
13	RF (Refund Adjustment)			0.0000	0.0000	0.0000
14	Total			0.0000	0.0000	0.0000
15						
16	Gross Margin:					
17	First	300	Mcf	1.1900	1.1900	0.0000
18	Next	14,700	Mcf	0.6590	0.6590	0.0000
19	Over	15,000	Mcf	0.4300	0.4300	0.0000
20						

Comparison of Current and Previous Cases
Interruptible Transportation and Carriage Service

Line No.	Description			Case No. 2005-00552	Case No. 2006-00000	Difference
				$/Mcf	$/Mcf	$/Mcf
1	**General Transporation (T-2)**					
2						
3	Interruptible Service (G-2)					
4	Simple Margin (Base Rate per Case No. 99-070):					
5	First	15,000	Mcf	0.5300	0.5300	0.0000
6	Over	15,000	Mcf	0.3591	0.3591	0.0000
7						
8	Non-Commodity Components:					
9	Demand			0.2195	0.1839	(0.0356)
10	Take-Or-Pay			0.0000	0.0000	0.0000
11	Transition Costs			0.0000	0.0000	0.0000
12	RF (Refund Adjustment)			0.0000	0.0000	0.0000
13	Total			0.2195	0.1839	(0.0356)
14						
15	Gross Margin:					
16	First	15,000	Mcf	0.7495	0.7139	(0.0356)
17	Over	15,000	Mcf	0.5786	0.5430	(0.0356)
18						
19	**Carriage Service**					
20						
21	Carriage Service (T-3)					
22	Simple Margin (Base Rate per Case No. 99-070):					
23	First	15,000	Mcf	0.5300	0.5300	0.0000
24	Over	15,000	Mcf	0.3591	0.3591	0.0000
25						
26	Non-Commodity Components:					
28	Take-Or-Pay			0.0000	0.0000	0.0000
30	RF (Refund Adjustment)			0.0000	0.0000	0.0000
31	Total			0.0000	0.0000	0.0000
32						
33	Gross Margin:					
34	First	15,000	Mcf	0.5300	0.5300	0.0000
35	Over	15,000	Mcf	0.3591	0.3591	0.0000
36						

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Texas Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**SL to Zone 2**							
2	NNS Contract #	N0210		12,617,673				
3	Base Rate		20		0.3088	3,896,336	3,896,336	
4	GSR		20		0.0000	0		0
5	TCA Adjustment		20		0.0000	0	0	
6	Unrec TCA Surch		20		0.0000	0	0	
7	ISS Credit		20		0.0000	0	0	
8	Misc Rev Cr Adj		20		0.0000	0	0	
9	GRI		20		0.0000	0	0	
6								
7	Total SL to Zone 2			12,617,673		3,896,336	3,896,336	0
8								
9	**SL to Zone 3**							
10	NNS Contract #	N0340		27,480,375				
11	Base Rate		20		0.3543	9,736,297	9,736,297	
12	GSR		20		0.0000	0		0
13	TCA Adjustment		20		0.0000	0	0	
14	Unrec TCA Surch		20		0.0000	0	0	
15	ISS Credit		20		0.0000	0	0	
16	Misc Rev Cr Adj		20		0.0000	0	0	
17	GRI		20		0.0000	0	0	
18								
19	FT Contract #	3355		3,130,605				
20	Base Rate		24		0.2494	780,773	780,773	
21	GSR		24		0.0000	0		0
22	TCA Adjustment		24		0.0000	0	0	
23	Unrec TCA Surch		24		0.0000	0	0	
24	ISS Credit		24		0.0000	0	0	
25	Misc Rev Cr Adj		24		0.0000	0	0	
26	GRI		24		0.0000	0	0	
27								
28								
29	Total SL to Zone 3			30,610,980		10,517,070	10,517,070	0
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Texas Gas

Line No.	Description	Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
			MMbtu	$/MMbtu	$	$	$
1	**Zone 1 to Zone 3**						
2	FT Contract # 3355		2,344,395				
3	Base Rate	24		0.2194	514,360	514,360	
4	GSR	24		0.0000	0		0
5	TCA Adjustment	24		0.0000	0	0	
6	Unrec TCA Surch	24		0.0000	0	0	
7	ISS Credit	24		0.0000	0	0	
8	Misc Rev Cr Adj	24		0.0000	0	0	
9	GRI	24		0.0000	0	0	
6							
7	Total Zone 1 to Zone 3		2,344,395		514,360	514,360	0
8							
9	**SL to Zone 4**						
10	NNS Contract # N0410		3,320,769				
11	Base Rate	20		0.4190	1,391,402	1,391,402	
12	GSR	20		0.0000	0		0
13	TCA Adjustment	20		0.0000	0	0	
14	Unrec TCA Surch	20		0.0000	0	0	
15	ISS Credit	20		0.0000	0	0	
16	Misc Rev Cr Adj	20		0.0000	0	0	
17	GRI	20		0.0000	0	0	
18							
19	FT Contract # 3819		1,277,500				
20	Base Rate	24		0.3142	401,391	401,391	
21	GSR	24		0.0000	0		0
22	TCA Adjustment	24		0.0000	0	0	
23	Unrec TCA Surch	24		0.0000	0	0	
24	ISS Credit	24		0.0000	0	0	
25	Misc Rev Cr Adj	24		0.0000	0	0	
26	GRI	24		0.0000	0	0	
27							
28	Total SL to Zone 4		4,598,269		1,792,793	1,792,793	0
29							
30	Total SL to Zone 2		12,617,673		3,896,336	3,896,336	0
31	Total SL to Zone 3		30,610,980		10,517,070	10,517,070	0
32	Total Zone 1 to Zone 3		2,344,395		514,360	514,360	0
33							
34	Total Texas Gas		50,171,317		16,720,559	16,720,559	0
35							
36							
37	Vendor Reservation Fees (Fixed)				0	0	
38							
39	TOP & Direct Billed Transition costs				0		
40							
41	Total Texas Gas Area Non-Commodity				16,720,559	16,720,559	0
42							
43							

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Tennessee Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**0 to Zone 2**							
2	FT-G Contract #	2546.1		12,844	9.0600			
3	Base Rate		23B		9.0600	116,367	116,367	
4	Settlement Surcharge		23B		0.0000	0		0
5	PCB Adjustment		23B		0.0000	0		0
6								
7	FT-G Contract #	2548.1		4,363	9.0600			
8	Base Rate		23B		9.0600	39,529	39,529	
9	Settlement Surcharge		23B		0.0000	0		0
10	PCB Adjustment		23B		0.0000	0		0
11								
12	FT-G Contract #	2550.1		5,739	9.0600			
13	Base Rate		23B		9.0600	51,995	51,995	
14	Settlement Surcharge		23B		0.0000	0		0
15	PCB Adjustment		23B		0.0000	0		0
16								
17	FT-G Contract #	2551.1		4,447	9.0600			
18	Base Rate		23B		9.0600	40,290	40,290	
19	Settlement Surcharge		23B		0.0000	0		0
20	PCB Adjustment		23B		0.0000	0		0
21								
22								
23	Total Zone 0 to 2			27,393		248,181	248,181	0
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Tennessee Gas

Line No.	Description	Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
			MMbtu	$/MMbtu	$	$	$
1	**1 to Zone 2**						
2	FT-G Contract # 2546		114,156	7.6200			
3	Base Rate	23B		7.6200	869,869	869,869	
4	Settlement Surcharge	23B		0.0000	0		0
5	PCB Adjustment	23B		0.0000	0		0
6							
7	FT-G Contract # 2548		44,997	7.6200			
8	Base Rate	23B		7.6200	342,877	342,877	
9	Settlement Surcharge	23B		0.0000	0		0
10	PCB Adjustment	23B		0.0000	0		0
11							
12	FT-G Contract # 2550		59,741	7.6200			
13	Base Rate	23B		7.6200	455,226	455,226	
14	Settlement Surcharge	23B		0.0000	0		0
15	PCB Adjustment	23B		0.0000	0		0
16							
17	FT-G Contract # 2551		45,058	7.6200			
18	Base Rate	23B		7.6200	343,342	343,342	
19	Settlement Surcharge	23B		0.0000	0		0
20	PCB Adjustment	23B		0.0000	0		0
21							
22	Total Zone 1 to 2		263,952		2,011,314	2,011,314	0
23							
24	Total Zone 0 to 2		27,393		248,181	248,181	0
25							
26	Total Zone 1 to 2 and Zone 0 to 2		291,345		2,259,495	2,259,495	0
27							
28	**Gas Storage**						
29	Production Area:						
30	Demand	27	34,968	2.0200	70,635	70,635	
31	Space Charge	27	4,916,148	0.0248	121,920	121,920	
32	Market Area:						
33	Demand	27	237,408	1.1500	273,019	273,019	
34	Space Charge	27	10,846,308	0.0185	200,657	200,657	
35	Total Storage				666,231	666,231	
36							
37	Vendor Reservation Fees (Fixed)				0	0	
38							
39	TOP & Direct Billed Transition costs				0	0	0
40							
41	Total Tennessee Gas Area FT-G Non-Commodity				2,925,726	2,925,726	0
42							
43							
44							
45							
46							
47							
48							
49							
50							
51							

Atmos Energy Corporation
Expected Gas Cost - Commodity
Purchases in Texas Gas Service Area

Exhibit B
Page 5 of 11

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) MMbtu	(3) Rate $/MMbtu	(4) Total $
1	No Notice Service				6,056,100		
2	Indexed Gas Cost (Texas Gas Payback)					7.1940	43,567,583
3	Commodity	20				0.0508	307,650
4	Fuel and Loss Retention @	36	2.15%			0.1581	957,469
5						7.4029	44,832,702
6							
7	Firm Transportation				91,000		
8	Indexed Gas Cost					7.1940	654,654
9	Base (Weighted on MDQs)	25				0.0439	3,995
10	TCA Adjustment	25				0.0000	0
11	Unrecovered TCA Surcharge	25				0.0000	0
12	Cash-out Adjustment	25				0.0000	0
13	GRI	25				0.0000	0
14	ACA	25				0.0018	164
15	Fuel and Loss Retention @	36	1.94%			0.1423	12,949
16						7.3820	671,762
17	No Notice Storage						
18	Net (Injections)/Withdrawals				(3,025,257)		
19	Indexed Gas Cost					7.1940	(21,763,699)
20	Commodity (Zone 3)	20				0.0508	(153,683)
21	Fuel and Loss Retention @	36	2.15%			0.1581	(478,293)
22						7.4029	(22,395,675)
23							
24							
25	Total Purchases in Texas Area				3,121,843	7.4023	23,108,789
26							
27							

28 Used to allocate transportation non-commodity

Line No.		Annualized MDQs in MMbtu	Allocation	Commodity Charge $/MMbtu	Weighted Average
29					
30					
31					
32	Texas Gas				
33	SL to Zone 2	12,617,673	25.15%	$0.0399	$ 0.0100
34	SL to Zone 3	30,610,980	61.01%	0.0445	0.0271
35	1 to Zone 3	2,344,395	4.67%	0.0422	0.0020
36	SL to Zone 4	4,598,269	9.17%	0.0528	0.0048
37	Total	50,171,317	100.00%		$ 0.0439
38					
39	Tennessee Gas				
40	0 to Zone 2	27,393	9.40%	0.0880	$ 0.0083
41	1 to Zone 2	263,952	90.60%	0.0776	0.0703
42	Total	291,345	100.00%		$ 0.0786
43					

Atmos Energy Corporation
Expected Gas Cost - Commodity
Purchases in Tennessee Gas Service Area

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	FT-A and FT-G				752,991		
2	Indexed Gas Cost					7.1940	5,417,017
3	Base Commodity (Weighted on MDQs)					0.0786	59,185
4	GRI	23C				0.0000	0
5	ACA	23C				0.0018	1,355
6	Transition Cost	23C				0.0000	0
7	Fuel and Loss Retention	29	3.69%			0.2756	207,524
8						7.5500	5,685,081
9							
10							
11	FT-GS				136,694		
12	Indexed Gas Cost					7.1940	983,377
13	Base Rate	20				0.5844	79,884
14	GRI	20				0.0000	0
15	ACA	20				0.0018	246
16	PCB Adjustment	20				0.0000	0
17	Settlement Surcharge	20				0.0000	0
18	Fuel and Loss Retention	29	3.69%			0.2756	37,673
19						8.0558	1,101,180
20							
21							
22	Gas Storage						
23	FT-A & FT-G Market Area (Injections)/Withdrawals				(566,031)		
24	Indexed Gas Cost/Storage					7.1940	(4,072,027)
25	Injection Rate	27				0.0102	(5,774)
26	Fuel and Loss Retention	27	1.49%			0.1088	(61,584)
27	Total					7.3130	(4,139,385)
28							
29							
30	FT-GS Market Area (Injections)/Withdrawals				(107,814)		
31	Indexed Gas Cost/Storage					7.1940	(775,614)
32	Injection Rate	27				0.0102	(1,100)
33	Fuel and Loss Retention	27	1.49%			0.1088	(11,730)
34	Total					7.3130	(788,444)
35							
36							
37	Total Tennessee Gas Zones				215,840	8.6102	1,858,432
38							
39							

Atmos Energy Corporation
Expected Gas Cost
Trunkline Gas

Commodity

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	Firm Transportation						
2	Expected Volumes				92,000		
3	Indexed Gas Cost					7.1940	661,848
4	Base Commodity					0.0213	1,960
5	GRI	10				-	0
6	ACA	10				0.0019	175
7	Fuel and Loss Retention	10	1.11%			0.0807	7,424
8						7.2979	671,407
9							
10							

Non-Commodity

Line No.	Description		(1) Tariff Sheet No.	(2) Annual Units MMbtu	(3) Rate $/MMbtu	(4) Non-Commodity Total $	(5) Non-Commodity Demand $	(6) Transition Costs $
11	FT-G Contract #	014573		87,475				
12	Discount Rate on MDQs				7.2000	629,820	629,820	
13								
14				92,125				
15	GRI Surcharge		10			0	-	
16								
17	Reservation Fee					-	-	
18								
19	Total Trunkline Area Non-Commodity					629,820	629,820	
20								
21								

Atmos Energy Corporation
Demand Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Total Demand Cost:						
2	Texas Gas	$16,720,559					
3	Midwestern	0					
4	Tennessee Gas	2,925,726					
5	Trunkline	629,820					
6	Total	$20,276,105					
7							
8			Allocated	Related	Monthly Demand Charge		
9	Demand Cost Allocation:	Factors	Demand	Volumes	Firm	Interruptible	HLF
10	All	0.1850	$3,751,079	20,401,274	0.1839	0.1839	0.1839
11	Firm	0.8150	16,525,026	18,923,274	0.8733	NA	NA
12	Total	1.0000	$20,276,105		1.0572	0.1839	0.1839
13							
14			Volumetric Basis for				
15		Annualized	Monthly Demand Charge				
16		Mcf @14.65	All	Firm			
17	Firm Service						
18	Sales:						
19	G-1	18,887,274	18,887,274	18,887,274	1.0572		
20	HLF	60,000	60,000		0.1839 + HLF MDQ Demand		
21	LVS-1	0	0	0	1.0572		
22	Total Firm Sales	18,947,274	18,947,274	18,887,274			
23							
24	Transportation:						
25	T-2 \ G-1	36,000	36,000	36,000	1.0572		
26	HLF	0	0		0.1839		
27	Total Firm Service	18,983,274	18,983,274	18,923,274			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	684,000	684,000		1.0572	0.1839	
32	LVS-2	154,000	154,000		1.0572	0.1839	
33	Total Sales	838,000	838,000				
34							
35	Transportation:						
36	T-2 \ G-2	580,000	580,000		1.0572	0.1839	
37							
38	Total Interruptible Service	1,418,000	1,418,000				
39							
40	Carriage Service						
41	T-3 & T-4	23,438,000					
42							
43	Total	43,839,274	20,401,274	18,923,274			
44							
45	HLF MDQ Demand						
46	Firm Demand Cost		$16,525,026				
47	Peak Day Thru-put		302,152	Mcf/Peak Day			
48	Times:		12	Months/Year			
49	Total Annualized Peak Day Demand		3,625,824				
50	Demand Charge per MDQ		$4.5576	/ MDQ of Customer's Contract			
51							
52							
53	Note: LVS Credit =	($28,321)					

Atmos Energy Corporation
Take-or-Pay and Transition Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Other Fixed Charges	Take-or-Pay	Transition				
2	Texas Gas		$0				
3	Tennessee Gas		0				
4	Total	$0	$0				
5							
6							
7			Related	Charge			
8	Other Fixed Charges	Amount	Volumes	$/Mcf			
9	Take-or-Pay	0	43,839,274	0.0000			
10	Transition	0	20,401,274	0.0000			
11	Total	$0		0.0000			
12							
13							
14			Volumetric Basis for				
15		Annual	Other Fixed Charges			Other Fixed Charges	
16		Expected Mcf	Take-or-Pay	Transition		Take-or-Pay	Transition
17	Firm Service						
18	Sales:						
19	G-1	18,887,274	18,887,274	18,887,274			0.0000
20	HLF	60,000	60,000	60,000			0.0000
21	LVS-1	0	0	0			0.0000
22	Total Firm Sales	18,947,274	18,947,274	18,947,274			
23							
24	Transportation:						
25	T-2 \ G-1	36,000	36,000	36,000			0.0000
26	T-2 \ G-1 \ HLF	0					0.0000
27	Total Firm Service	18,983,274	18,983,274	18,983,274			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	684,000	684,000	684,000			0.0000
32	LVS-2	154,000	154,000	154,000			0.0000
33	Total Sales	838,000	838,000	838,000			
34							
35	Transportation:						
36	T-2 \ G-2	580,000	580,000	580,000			0.0000
37							
38	Total Interruptible Service	1,418,000	1,418,000	1,418,000			
39							
40	Carriage Service						
41	T-3 & T-4	23,438,000	23,438,000	NA			
42							
43	Total	43,839,274	43,839,274	20,401,274			
44							
45							
46	Note: LVS Credit =	$0					
47							

Atmos Energy Corporation
Expected Gas Cost - Commodity
Total System

Line No.	Description		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	Texas Gas Area					
2	No Notice Service		5,908,390	6,056,100	7.4029	44,832,702
3	Firm Transportation		88,780	91,000	7.3820	671,762
4	No Notice Storage		(2,951,470)	(3,025,257)	7.4029	(22,395,675)
5	Total Texas Gas Area		3,045,700	3,121,843	7.4023	23,108,789
6						
7	Tennessee Gas Area					
8	FT-A and FT-G		724,030	752,991	7.5500	5,685,081
9	FT-GS		131,437	136,694	8.0558	1,101,180
10	Gas Storage					
11	FT-A and FT-G Injections		(544,261)	(566,031)	7.3130	(4,139,385)
12	FT-GS Withdrawals		(103,667)	(107,814)	7.3130	(788,444)
13			207,539	215,840	8.6102	1,858,432
14	Trunkline Gas Area					
15	Firm Transportation		88,889	92,000	7.2979	671,407
16						
17						
18	WKG System Storage					
19	Injections		(2,278,774)	(2,335,743)	7.4029	(17,291,272)
20	Withdrawals		0	0	8.0100	0
21	Net WKG Storage		(2,278,774)	(2,335,743)	7.4029	(17,291,272)
22						
23						
24	Local Production		59,512	61,000	7.3820	450,302
25						
26						
27						
28	Total Commodity Purchases		1,122,866	1,154,940	7.6174	8,797,658
29						
30	Lost & Unaccounted for @	1.38%	15,495	15,938		
31						
32	Total Deliveries		1,107,371	1,139,002	7.7240	8,797,658
33						
34	LVS Commodity Credit to System					
35	LVS Sales		(50,000)	(51,428)	7.5212	(386,800)
36						
37						
38	Total Expected Commodity Cost		1,057,371	1,087,574	7.7336	8,410,858
39						
40	Expected Commodity Cost ($/Mcf)				7.9545	
41						
42						
43						

Atmos Energy Corporation
Load Factor Calculation for Demand Allocation

Line No.	Description	MCF	
	Annualized Volumes Subject to Demand Charges		
1	Sales Volume	19,631,274	
2	Large Volume Sales (Annualized)	154,000	
3	Transportation	616,000	
4	Total Mcf Billed Demand Charges	20,401,274	
5	Divided by: Days/Year	365	
7	Average Daily Sales and Transport Volumes	55,894	
8			
10	Peak Day Sales and Transportation Volume		
11	Estimated total company firm requirements for 5 degree average		
12	temperature day from Peak Day Book - with adjustments per rate filing	302,152	Mcf/Peak Day
13			
14			
15	New Load Factor (line 7 / line 12)	0.1850	

Seventh Revised Sheet No. 20 : Effective

Superseding: Substitute Sixth Revised Sheet No. 20

Currently Effective Maximum Transportation Rates ($ per MMBtu)
For Service Under Rate Schedule NNS

	Base Tariff Rates (1)	FERC ACA (2)	Currently Effective Rates (3)
Zone SL			
Daily Demand	0.1800		0.1800
Commodity	0.0253	0.0018	0.0271
Overrun	0.2053	0.0018	0.2071
Zone 1			
Daily Demand	0.2782		0.2782
Commodity	0.0431	0.0018	0.0449
Overrun	0.3213	0.0018	0.3231
Zone 2			
Daily Demand	0.3088		0.3088
Commodity	0.0460	0.0018	0.0478
Overrun	0.3548	0.0018	0.3566
Zone 3			
Daily Demand	0.3543		0.3543
Commodity	0.0490	0.0018	0.0508
Overrun	0.4033	0.0018	0.4051
Zone 4			
Daily Demand	0.4190		0.4190
Commodity	0.0614	0.0018	0.0632
Overrun	0.4804	0.0018	0.4822

Minimum Rate: Demand $-0-; Commodity - Zone SL 0.0163
Zone 1 0.0186
Zone 2 0.0223
Zone 3 0.0262
Zone 4 0.0308

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental transportation charge of:

Daily Demand	$0.0621
Commodity	$0.0155
Overrun	$0.0776

This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Fifth Revised Sheet No. 24 : Effective

Superseding: Substitute Fourth Revised Sheet No. 24

Currently Effective Maximum Daily Demand Rates ($ per MMBtu)
For Service Under Rate Schedule FT

	Currently Effective Rates [1]
SL-SL	0.0794
SL-1	0.1552
~~SL-2~~	~~0.2120~~
~~SL-3~~	~~0.2494~~
~~SL-4~~	~~0.3142~~
1-1	0.1252
1-2	0.1820
~~1-3~~	~~0.2194~~
1-4	0.2842
2-2	0.1332
2-3	0.1705
2-4	0.2334
3-3	0.1181
3-4	0.1810
4-4	0.1374

Minimum Rates: Demand $-0-

Backhaul rates equal fronthaul rates to zone of delivery.

[1] Currently Effective Rates are equal to the Base Tariff Rates.

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental Daily Demand charge of $0.0621. This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Sixth Revised Sheet No. 25 : Effective

Superseding: Substitute Fifth Revised Sheet No. 25

Currently Effective Maximum Commodity Rates ($ per MMBtu)
For Service Under Rate Schedule FT

	Base Tariff Rates (1)	FERC ACA (2)	Currently Effective Rates (3)
SL-SL	0.0104	0.0018	0.0122
SL-1	0.0355	0.0018	0.0373
SL-2	0.0399	0.0018	0.0417
SL-3	0.0445	0.0018	0.0463
SL-4	0.0528	0.0018	0.0546
1-1	0.0337	0.0018	0.0355
1-2	0.0385	0.0018	0.0403
1-3	0.0422	0.0018	0.0440
1-4	0.0508	0.0018	0.0526
2-2	0.0323	0.0018	0.0341
2-3	0.0360	0.0018	0.0378
2-4	0.0446	0.0018	0.0464
3-3	0.0312	0.0018	0.0330
3-4	0.0398	0.0018	0.0416
4-4	0.0360	0.0018	0.0378

Minimum Rates: Commodity minimum base rates are presented on Sheet 31.

Backhaul rates equal fronthaul rates to zone of delivery.

Note: For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental Commodity charge of $0.0155. This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Third Revised Sheet No. 36 : Effective
Superseding: Second Revised Sheet No. 36

Schedule of Currently Effective Fuel Retention Percentages
Pursuant to Section 16 of the General Terms and Conditions

NNS/SGT/SNS RATE SCHEDULES

NNS/SGT WINTER

Delivery Zone	PFRP{1}	FAP{2}	EFRP{3}
SL	0.59%	0.41%	1.00%
1	2.54%	(0.18%)	2.36%
2	2.79%	(0.36%)	2.43%
3	3.07%	(0.34%)	2.73%
4	4.31%	(1.29%)	3.02%

NNS/SGT/SNS SUMMER

Delivery Zone	PFRP{1}	FAP{2}	EFRP{3}
SL	0.15%	(0.15%)	0.00%
1	2.21%	(0.29%)	1.92%
2	2.39%	(0.38%)	2.01%
3	2.63%	(0.48%)	2.15%
4	2.98%	(0.83%)	2.15%

FT/STF/STFX/IT/ITX RATE SCHEDULES

WINTER

Rec/Del Zone	PFRP	FAP	EFRP
SL/SL	0.28%	0.67%	0.95%
SL or 1/1	1.74%	(0.46%)	1.28%
SL or 1/2	2.12%	(0.20%)	1.92%
SL or 1/3	2.33%	0.51%	2.84%
SL or 1/4	2.98%	(0.08%)	2.90%
2/2	0.11%	0.35%	0.46%
2/3	0.21%	0.71%	0.92%
2/4	0.86%	0.12%	0.98%
3/3	0.11%	0.35%	0.46%
3/4	0.65%	0.00%	0.65%
4/4	0.33%	0.00%	0.33%

SUMMER

Rec/Del Zone	PFRP	FAP	EFRP
SL/SL	0.23%	0.73%	0.96%
SL or 1/1	1.50%	(0.44%)	1.06%
SL or 1/2	2.10%	(1.03%)	1.07%
SL or 1/3	2.13%	(0.19%)	1.94%
SL or 1/4	2.96%	(0.40%)	2.56%
2/2	0.01%	0.43%	0.44%
2/3	0.03%	0.84%	0.87%
2/4	0.86%	0.63%	1.49%
3/3	0.01%	0.43%	0.44%
3/4	0.83%	0.00%	0.83%
4/4	0.42%	0.00%	0.42%

FSS/ISS RATE SCHEDULES

Withdrawal

PFRP	FAP	EFRP
0.89%	0.35%	1.24%

Injection

PFRP	FAP	EFRP
0.72%	0.28%	1.00%

{1} Projected Fuel Retention Percentage
{2} Fuel Adjustment Percentage
{3} Effective Fuel Retention Percentage

Thirty-Second Revised Sheet No. 20 : Effective

Superseding: Thirty-First Revised Sheet No. 20

RATES PER DEKATHERM

FIRM TRANSPORTATION - GS RATES (FT-GS)

Base Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.2138		$0.4203	$0.5844	$0.6748	$0.7814	$0.8952	$1.0698
L		$0.1771						
1	$0.4318		$0.3268	$0.4951	$0.5849	$0.6915	$0.8052	$0.9804
2	$0.5844		$0.4951	$0.2000	$0.2897	$0.4144	$0.5106	$0.6852
3	$0.6748		$0.5849	$0.2897	$0.1489	$0.3995	$0.4951	$0.6698
4	$0.7995		$0.7096	$0.4144	$0.3995	$0.1886	$0.2311	$0.4061
5	$0.8952		$0.8052	$0.5106	$0.4951	$0.2311	$0.1989	$0.3466
6	$1.0698		$0.9804	$0.6852	$0.6698	$0.4061	$0.3466	$0.2374

Surcharges

PCB Adjustment: 1/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
L		$0.0000						
1	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
3	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
4	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
5	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
6	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Annual Charge Adjustment (ACA): $0.0018

Maximum Rates 2/, 3/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.2156		$0.4221	$0.5862	$0.6766	$0.7832	$0.8970	$1.0716
L		$0.1789						
1	$0.4336		$0.3286	$0.4969	$0.5867	$0.6933	$0.8070	$0.9822
2	$0.5862		$0.4969	$0.2018	$0.2915	$0.4162	$0.5124	$0.6870
3	$0.6766		$0.5867	$0.2915	$0.1507	$0.4013	$0.4969	$0.6716
4	$0.8013		$0.7114	$0.4162	$0.4013	$0.1904	$0.2329	$0.4079
5	$0.8970		$0.8070	$0.5124	$0.4969	$0.2329	$0.2007	$0.3484
6	$1.0716		$0.9822	$0.6870	$0.6716	$0.4079	$0.3484	$0.2392

Minimum Rates

DELIVERY ZONE

Tennessee Gas Pipeline

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Notes:

1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

3/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Seventeenth Revised Sheet No. 23A : Effective

Superseding: Sixteenth Revised Sheet No. 23A

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0457		$0.0687	$0.0898	$0.0996	$0.1136	$0.1249	$0.1626
L		$0.0304						
1	$0.0687		$0.0590	$0.0794	$0.0892	$0.1032	$0.1144	$0.1521
2	$0.0898		$0.0794	$0.0451	$0.0548	$0.0699	$0.0801	$0.1177

3	$0.0996	$0.0892	$0.0548	$0.0384	$0.0681	$0.0783	$0.1160
4	$0.1147	$0.1043	$0.0699	$0.0681	$0.0419	$0.0477	$0.0852
5	$0.1249	$0.1144	$0.0801	$0.0783	$0.0477	$0.0445	$0.0783
6	$0.1626	$0.1521	$0.1177	$0.1160	$0.0852	$0.0783	$0.0660

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0018

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Fourteenth Revised Sheet No. 23B : Effective

Superseding: Thirteenth Revised Sheet No. 23B

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-G

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
L		$0.00						
1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14

4	$12.53	$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09	$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59	$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-G Reservation Rate is $0.00 per Dth
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Notes:
1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.
2/ Maximum rates are inclusive of base rates and above surcharges.

Fifteenth Revised Sheet No. 23C : Effective

Superseding: Fourteenth Revised Sheet No. 23C

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-G

Base Commodity Rate

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	<u>$0.0880</u>	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	<u>$0.0776</u>	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0457		$0.0687	$0.0898	$0.0996	$0.1136	$0.1249	$0.1626
L		$0.0304						
1	$0.0687		$0.0590	$0.0794	$0.0892	$0.1032	$0.1144	$0.1521
2	$0.0898		$0.0794	$0.0451	$0.0548	$0.0699	$0.0801	$0.1177

3	$0.0996	$0.0892	$0.0548	$0.0384	$0.0681	$0.0783	$0.1160
4	$0.1147	$0.1043	$0.0699	$0.0681	$0.0419	$0.0477	$0.0852
5	$0.1249	$0.1144	$0.0801	$0.0783	$0.0477	$0.0445	$0.0783
6	$0.1626	$0.1521	$0.1177	$0.1160	$0.0852	$0.0783	$0.0660

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0018

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Fifteenth Revised Sheet No. 27 : Effective

Superseding: Fourteenth Revised Sheet No. 27

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA						
Deliverability Rate	$2.02			$0.00	$2.02	
Space Rate	$0.0248			$0.0000	$0.0248	1.49%
Injection Rate	$0.0053				$0.0053	
Withdrawal Rate	$0.0053				$0.0053	
Overrun Rate	$0.2427				$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA						
Deliverability Rate	$1.15			$0.00	$1.15	
Space Rate	$0.0185			$0.0000	$0.0185	1.49%
Injection Rate	$0.0102				$0.0102	
Withdrawal Rate	$0.0102				$0.0102	
Overrun Rate	$0.1380				$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA						
Space Rate	$0.0848			$0.0000	$0.0848	1.49%
Injection Rate	$0.0102				$0.0102	
Withdrawal Rate	$0.0102				$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA						
Space Rate	$0.0993			$0.0000	$0.0993	1.49%
Injection Rate	$0.0053				$0.0053	
Withdrawal Rate	$0.0053				$0.0053	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

Excess Withdrawal Rate	$0.7800	$0.0019		$0.7819	
SS-NE					

Deliverability	$6.71		$0.00	$6.71	
Space Rate	$0.0132		$0.0000	$0.0132	
Injection Rate	$0.0102			$0.0102	3.25%
Withdrawal Rate	$0.0936			$0.0936	
Excess Withdrawal Rate	$1.1600	$0.0019		$1.1619	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

First Revised Sheet No. 29 : Effective
Superseding: Substitute Original Sheet No. 29

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\, 3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interuptible Transportation-X, (FT-G) Firm Transportation-G, (EDS/ERS) FT- A Extended Transportation Service.

Eighth Revised Sheet No. 10 : Effective

Superseding: Seventh Revised Sheet No. 10

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

	Base Rate Per Dt (1)	Adjustments Sec. 24 (2)	Adjustments Sec. 25 (3)	Maximum Rate Per Dt (4)	Minimum Rate Per Dt (5)	Fuel Reimbursement (6)
RATE SCHEDULE FT						
Field Zone to Zone 2						
- Reservation Rate	$ 9.7097	-	$ 0.2800	$ 9.9897	-	-
- Usage Rate (1)	0.0141	-	-	0.0141	$ 0.0141	2.60 % (2)
- Overrun Rate (3)	0.3192	-	0.0092	0.3284	-	-
Zone 1A to Zone 2						
- Reservation Rate	$ 6.0096	-	$ 0.1900	$ 6.1996	-	-
- Usage Rate (1)	0.0117	-	-	0.0117	$ 0.0117	1.99 % (2)
- Overrun Rate (3)	0.1976	-	0.0062	0.2038	-	-
Zone 1B to Zone 2						
- Reservation Rate	$ 4.5557	-	$ 0.1900	$ 4.7457	-	-
- Usage Rate (1)	0.0062	-	-	0.0062	$ 0.0062	0.95 % (2)
- Overrun Rate (3)	0.1498	-	0.0062	0.1560	-	-
Zone 2 Only						
- Reservation Rate	$ 3.4350	-	$ 0.1900	$ 3.6250	-	-
- Usage Rate (1)	0.0011	-	-	0.0011	$ 0.0011	0.58 % (2)
- Overrun Rate (3)	0.1129	-	0.0062	0.1191	-	-
Field Zone to Zone 1B						
- Reservation Rate	$ 8.4890	-	$ 0.2800	$ 8.7690	-	-
- Usage Rate (1)	0.0130	-	-	0.0130	$ 0.0130	2.34 % (2)
- Overrun Rate (3)	0.2791	-	0.0092	0.2883	-	-
Zone 1A to Zone 1B						
- Reservation Rate	$ 4.7889	-	$ 0.1900	$ 4.9789	-	-
- Usage Rate (1)	0.0106	-	-	0.0106	$ 0.0106	1.73 % (2)
- Overrun Rate (3)	0.1574	-	0.0062	0.1636	-	-
Zone 1B Only						
- Reservation Rate	$ 3.3350	-	$ 0.1900	$ 3.5250	-	-
- Usage Rate (1)	0.0051	-	-	0.0051	$ 0.0051	0.69 % (2)
- Overrun Rate (3)	0.1096	-	0.0062	0.1158	-	-
Field Zone to Zone 1A						
- Reservation Rate	$ 7.3683	-	$ 0.2800	$ 7.6483	-	-

Trunkline

- Usage Rate (1)	0.0079	-	-	0.0079	$ 0.0079	1.97 % (2)
- Overrun Rate (3)	0.2422	-	0.0092	0.2514	-	-
Zone 1A Only						
- Reservation Rate	$ 3.6682	-	$ 0.1900	$ 3.8582	-	-
- Usage Rate (1)	0.0055	-	-	0.0055	$ 0.0055	1.36 % (2)
- Overrun Rate (3)	0.1206	-	0.0062	0.1268	-	-
Field Zone Only						
- Reservation Rate	$ 3.7001	-	$ 0.0900	$ 3.7901	-	-
- Usage Rate (1)	0.0024	-	-	0.0024	$ 0.0024	0.93 % (2)
- Overrun Rate (3)	0.1216	-	0.0030	0.1246	-	-
Gathering Charge (All Zones)						
- Reservation Rate	$ 0.3257			$ 0.3257		
- Overrun Rate (3)	0.0107			0.0107		

(1) Excludes Section 21 Annual Charge Adjustment: $0.0018
(2) Fuel reimbursement for backhauls is 0.43%
(3) Maximum firm volumetric rate applicable for capacity release

Atmos Energy Corporation
Basis for Indexed Gas Cost
For the Quarter of May 2006 - July 2006
2006-00000

The projected commodity price was provided by the Gas Supply **Department and was based upon the following:**

A. **The Gas Supply Department** reviewed the **NYMEX** futures close prices for the quarter of *May 2006 - July 2006 during the period March 15, 2006 through March 23, 2006* which are listed below:

		MAY 2006 ($/MMBTU)	JUN 2006 ($/MMBTU)	JUL 2006 ($/MMBTU)
Wednesday	15-Mar	7.304	7.444	7.589
Thursday	16-Mar	7.412	7.549	7.689
Friday	17-Mar	7.208	7.354	7.500
Monday	20-Mar	6.978	7.141	7.304
Tuesday	21-Mar	7.011	7.176	7.341
Wednesday	22-Mar	7.103	7.273	7.443
Thursday	23-Mar	7.467	7.630	7.793
		$7.212	$7.367	$7.523

B. Gas Supply believes prices will remain stable and prices for the quarter of May 2006 - July 2006 will settle at 7.194 per Mmbtu for the period that the GCA is to be effective.

In support of Item B, a worksheet entitled "Estimated Weighted Average Cost of Gas" has been filed under a Petition for Confidentiality in this Case.

Atmos Energy Corporation
Kentucky Division
For the Month of February, 2006

For Kentucky customers served in:		Indexed 1 Cash-out Price		Transport Charge 2, 3		WKG Cash-out Price
A. Texas Gas: Zone 2 Area	100% of Index Price	$7.2970	+	$0.0530	=	$7.3500
	90% of Index Price	6.5673	+	0.0530	=	6.6203
	80% of Index Price	5.8376	+	0.0530	=	5.8906
Zone 3 Area	100% of Index Price	$7.2970	+	$0.0563	=	$7.3533
	90% of Index Price	6.5673	+	0.0563	=	6.6236
	80% of Index Price	5.8376	+	0.0563	=	5.8939
Zone 4 Area	100% of Index Price	$7.2970	+	$0.0685	=	$7.3655
	90% of Index Price	6.5673	+	0.0685	=	6.6358
	80% of Index Price	5.8376	+	0.0685	=	5.9061
B. Tennessee Gas: Zone 2 Area	100% of Index Price	$7.4086	+	$0.0898	=	$7.4984
	90% of Index Price	6.6677	+	0.0898	=	6.7575
	80% of Index Price	5.9269	+	0.0898	=	6.0167

[1] Indexed cash-out price is from the pipeline's Electronic Bulletin Board.

[2] Transport charge used for Texas Gas is its tariff sheet no. 20 commodity rate.

[3] Transport charge used for Tennessee Gas is its tariff sheet no. 23A maximum commodity rate from zone 0 to zone 2.

Atmos Energy Corporation
Estimated Weighted Average Cost of Gas
May-06 Through July-06

	May-06			June-06			July-06			Total		
	Volumes	Rate	Value	Volumes	Rate	Value	Volumes	Rate	Value	Volumes	Rate	Value
Texas Gas												
Trunkline												
Tennessee Gas												
TX Gas Storage												
TN Gas Storage												
WKG Storage												
Midwestern												
Storage												
Market												
WACOGs												

(This information has been filed under a Petition for Confidentiality)

PUBLIC DISCLOSURE

Atmos Energy Corporation
Correction Factor (CF)
For the Three Months Ended January 1, 2006
Case No. 2006-000

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Month	Actual Sales Volume (Mcf)	Recoverable Gas Cost	Actual Recovered Gas Cost	Under (Over) Recovery Amount	Adjustments	Total
1	November-05	2,849,472	12,168,326.05	13,622,670.44	(1,454,344.39)	0.00	(1,454,344.39)
2							
3	December-05	3,142,867	27,969,453.46	35,353,498.55	(7,384,045.09)	0.00	(7,384,045.09)
4							
5	January-06	3,064,001	33,529,976.99	39,112,285.63	(5,582,308.64)	0.00	(5,582,308.64)
6							
7							
8							
9							
10							
11							
12							
13	Total Gas Cost						
14	Under/(Over) Recovery		73,667,756.50	88,088,454.62	(14,420,698.12)	0.00	(14,420,698.12)
15							
16							
17							
18	Account 191 Balance @ October, 2005						$14,649,349.19
19	Total Gas Cost Under/(Over) Recovery for the three months ended January, 2006						(14,420,698.12)
20	Recovery from outstanding Correction Factor (CF)						5,443,199.41
21	Account 191 Balance @ January, 2006						5,671,850.48
22							
23							
24							
25							
26							
27							
28	Derivation of Correction Factor (CF):						
29							
30	Account 191 Balance					$5,671,850	
31	Divided By: Total Expected Customer Sales					18,983,274	MCF
32							
33	Correction Factor (CF)					$0.2988	/MCF
34							
35							

Atmos Energy Corporation
Recoverable Gas Cost Calculation
For the Three Months Ended January 1, 2006
Case No. 2006-000

Exhibit D -
Page 2 of 5

Line No.	Description	Unit	(1) November-05	(2) Month December-05	(3) January-06	Source Document
		GL	Dec-05	Jan-06	Feb-06	
1	**Supply Volume**					
2	Pipelines:					
3	Texas Gas Transmission [1]	Mcf	0	0	0	
4	Tennessee Gas Pipeline [1]	Mcf	0	0	0	
5	Trunkline Gas Company [1]	Mcf	0	0	0	
6	Midwestern Pipeline [1]	Mcf	0	0	0	
7	**Total Pipeline Supply**	Mcf	0	0	0	
8	Total Other Suppliers	Mcf	416,280	1,516,374	1,625,771	pages 5
9	Off System Storage					
10	Texas Gas Transmission	Mcf	0	0	0	
11	Tennessee Gas Pipeline	Mcf	162,158	242,115	(284)	
12	System Storage					
13	Withdrawals	Mcf	336,956	1,105,202	915,844	
14	Injections	Mcf	(413,281)	0	0	
15	Producers	Mcf	15,462	11,895	(1,252)	
16	Pipeline Imbalances cashed out	Mcf	0	0	0	
17	System Imbalances [2]	Mcf	1,427,553	891,237	158,511	
18	**Total Supply**	Mcf	1,945,128	3,766,823	2,698,590	
19						
20	Change in Unbilled	Mcf	904,344	(623,956)	365,411	
21	Company Use	Mcf	0	0	0	
22	Unaccounted For	Mcf	0	0	0	
23	**Total Sales**	Mcf	2,849,472	3,142,867	3,064,001	

[1] Includes settlement of historical imbalances and prepaid items.

[2] Includes volumes banked from grandfathering or special contract and monthly cash out of endusers.

Atmos Energy Corporation
Recoverable Gas Cost Calculation
For the Three Months Ended January 1, 2006
Case No. 2006-000

Line No.	Description	Unit	(1) November-05	(2) December-05	(3) January-06	Source Document
		GL	Dec-05	Jan-06	Feb-06	
				Month		
1	**Supply Cost**					
2	Pipelines:					
3	Texas Gas Transmission [1]	$	2,021,363	2,104,291	2,061,745	
4	Tennessee Gas Pipeline [1]	$	326,432	342,366	363,225	
5	Trunkline Gas Company [1]	$	0	0	32,063	
6	Midwestern Pipeline [1]	$	30,132	32,054	0	
7	**Total Pipeline Supply**	$	2,377,927	2,478,711	2,457,034	
8	Total Other Suppliers	$	4,958,738	18,105,510	16,549,958	page 5
9	Hedging Settlements		0	0	0	
10	Off System Storage					
11	Texas Gas Transmission	$	0	0	0	
12	Tennessee Gas Pipeline	$	1,314,686	1,979,567	(106,011)	
13	WKG Storage		122,500	122,500	122,500	
14	System Storage					
15	Withdrawals	$	(1,874,568)	9,229,055	7,755,154	
16	Injections	$	0	0	0	
17	Producers	$	177,670	142,279	219,863	
18	Pipeline Imbalances cashed out	$	0	0	0	
19	System Imbalances [2]	$	15,362,269	5,611,265	2,085,277	
20	**Sub-Total**	$	22,439,221	37,668,886	29,083,775	
21						
22	Change in Unbilled	$	(10,270,895)	(9,699,433)	4,446,202	
23	Company Use	$	0	0	0	
24	Recovered thru Transportation	$	0	0	0	
25	**Total Recoverable Gas Cost**	$	12,168,326	27,969,453	33,529,977	

[1] Includes demand charges, cost of settlement of historical imbalances and prepaid items.

[2] Includes volumes banked from grandfathering or special contract and monthly cash out of endusers.

Atmos Energy Corporation
Recovery from Correction Factors (CF)
For the Three Months Ended January, 2006
Case No. 2006-000

Line No.	Month	Type of Sales	Mcf Sold	Rate	Amount
1	November-05	G-1 Sales	1,060,145.7	$0.7717	$818,114.44
2		G-1 HLF	0.0	0.7717	0.00
3		G-2 Sales	16,504.3	0.7717	12,736.34
4		T-3 Overrun Sales	3,664.0	0.8489	3,110.37
5		T-4 Overrun Sales	811.0	0.8489	688.46
6		LVS-1 Sales	0.0	0.0000	0.00
7		LVS-2 Sales	3,972.0	0.0000	0.00
8		LVS HLF Sales	0.0	0.0000	0.00
9		Total	1,085,097.0		834,649.61
10					
11	December-05	G-1 Sales	2,724,827.1	$0.7717	$2,102,749.06
12		G-1 HLF	0.0	0.7717	0.00
13		G-2 Sales	83,459.7	0.7717	64,405.81
14		T-3 Overrun Sales	16,433.0	0.8489	13,949.97
15		T-4 Overrun Sales	24,314.0	0.8489	20,640.15
16		LVS-1 Sales	0.0	0.0000	0.00
17		LVS-2 Sales	6,573.0	0.0000	0.00
18		LVS HLF Sales	0.0	0.0000	0.00
19		Total	2,855,606.7		2,201,744.99
20					
21	January-06	G-1 Sales	3,056,866.2	$0.7717	$2,358,983.64
22		G-1 HLF	0.0	0.7717	0.00
23		G-2 Sales	41,251.6	0.7717	31,833.84
24		T-3 Overrun Sales	18,769.0	0.8489	15,933.00
25		T-4 Overrun Sales	64.0	0.8489	54.33
26		LVS-1 Sales	0.0	0.0000	0.00
27		LVS-2 Sales	8,789.0	0.0000	0.00
28		LVS HLF Sales	0.0	0.0000	0.00
29		Total	3,125,739.8		2,406,804.81
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	Total Recovery from Correction Factor (CF)				$5,443,199.41
51					
52	LVS sales commodity is "trued-up" according to Section 3(f) in LVS tariff in P.S.C. No. 1.				
53					
54	When Carriage (T-3 and T-4) customers have a positive imbalance that has been approved by the				
55	Company, the customer is billed for the imbalance volumes at a rate equal to 110% of the Company's				
56	applicable sales rate according to Section 6(a) of P.S.C. No. 20, Sheet Nos. 41A and 47A.				

Atmos Energy Corporation
Detail Sheet for Supply Volumes & Costs
Traditional and Other Pipelines

		November, 2005		December, 2005		January, 2006	
	Description	MCF	Cost	MCF	Cost	MCF	Cost
1	**Texas Gas Pipeline Area**						
2	LG&E Natural						
3	Atmos Energy Marketing, LLC						
4	Texaco Gas Marketing						
5	CMS						
6	WESCO						
7	Southern Energy Company						
8	Union Pacific Fuels						
9	Atmos Energy Marketing, LLC						
10	Engage						
11	ERI						
12	Prepaid						
13	Reservation						
14	Hedging Costs - All Zones						
15							
16	**Total**	217,513	$2,566,018.88	1,080,471	$12,746,367.03	1,079,620	$10,993,300.17
17							
18							
19	**Tennessee Gas Pipeline Area**						
20	Atmos Energy Marketing, LLC						
21	Union Pacific Fuels						
22	WESCO						
23	Prepaid						
24	Reservation						
25	Fuel Adjustment						
26							
27	**Total**	111,703	$1,316,143.68	286,622	$3,465,844.94	394,682	$3,974,874.52
28							
29							
30	**Trunkline Gas Company**						
31	Atmos Energy Marketing, LLC						
32	Engage						
33	Prepaid						
34	Reservation						
35	Fuel Adjustment						
36							
37	**Total**	87,064	$1,076,575.07	149,910	$1,901,743.10	151,469	$1,581,783.66
38							
39							
40	**Midwestern Pipeline**						
41	Atmos Energy Marketing, LLC						
42	LG&E Natural						
43	Anadarko						
44	Prepaid						
45	Reservation						
46	Fuel Adjustment						
47							
48	**Total**	0	$0.00	(629)	($8,445.07)	0	$0.00
49							
50							
51	**All Zones**						
52	Total	416,280	$4,958,737.63	1,516,374	$18,105,510.00	1,625,771	$16,549,958.35
53							
54							
55		**** Detail of Volumes and Prices Has Been Filed Under Petition for Confidentiality ****					

PUBLIC DISCLOSURE

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

REFUND PLAN OF)
ATMOS ENERGY CORPORATION)

Case No. 2003-00377

CERTIFICATE OF COMPLIANCE

We hereby certify that the refund directed to be made by Order in Case No. 2003-00377 has been completed in the following manner:

Refund Detail

Customers Refund As Filed	$	(11,438.00)
Interest Accrued		(194.60)
Carry-over to next GCA Refund		259.78
Total	$	(11,372.82)

Refund by Class of Customer

Sales:		
Residential	$	6,622.69
Commercial		2,920.45
Industrial		920.57
Public Authority		860.85
T-3 Overrun Sales		34.06
T-4 Overrun Sales		14.20
Total	$	11,372.82

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

REFUND PLAN OF)
ATMOS ENERGY CORPORATION)

Case No. 2004-00269

CERTIFICATE OF COMPLIANCE

We hereby certify that the refund directed to be made by Order in Case No. 2004-00269 has been completed in the following manner:

Refund Detail

Customers Refund As Filed	$	(93,396.29)
Interest Accrued		(766.96)
Carry-over to next GCA Refund		511.28
Total	$	(93,651.97)

Refund by Class of Customer

Sales:		
Residential	$	53,316.59
Commercial		24,941.60
Industrial		7,859.20
Public Authority		7,177.49
T-3 Overrun Sales		150.42
T-4 Overrun Sales		206.67
Total	$	93,651.97

ATMOS ENERGY CORPORATION
Large Volume Sales
For the Period February, 2006

The net monthly rates for Large Volume Sales service is as follows:

Base Charge:

LVS-1 Service	$ 20.00	per Meter
LVS-2 Service	220.00	per Meter
Combined Service	220.00	per Meter

LVS-1:

Firm Service			Simple Margin		Non-Commodity Component [2]		Estimated Weighted Average Commodity Gas Cost		Sales Rate	
First	300 [1]	Mcf @	$ 1.1900	+	$ 1.2622	+	$ 10.3825	=	$ 12.8347	per Mcf
Next	14,700 [1]	Mcf @	0.6590	+	1.2622	+	10.3825	=	12.3037	per Mcf
All over	15,000	Mcf @	0.4300	+	1.2622	+	10.3825	=	12.0747	per Mcf
High Load Factor Firm Service										
Demand				@	5.4418	+	$0.0000	=	$ 5.4418	per Mcf of daily contract demand
First	300 [1]	Mcf @	$ 1.1900	+	$ 0.2195	+	$ 10.3825	=	$ 11.7920	per Mcf
Next	14,700 [1]	Mcf @	0.6590	+	0.2195	+	10.3825	=	11.2610	per Mcf
All over	15,000	Mcf @	0.4300	+	0.2195	+	10.3825	=	11.0320	per Mcf

LVS-2:

Interruptible Service										
First	15,000	Mcf @	$ 0.5300	+	$ 0.2195	+	$ 10.3825	=	$ 11.1320	per Mcf
All over	15,000	Mcf @	0.3591	+	0.2195	+	10.3825	=	10.9611	per Mcf

True-up Adjustment for 1/06 billing period: $ (1.8148) per Mcf

[1] All gas consumed by the customer will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] The Non-Commodity Component is from P.S.C. No. 20 Sixteenth Revised Sheet No. 6, effective February 1, 2006.

Atmos Energy Corporation
Large Volume Sales
Estimated WACOG used for Billing
For the Period February, 2006

Line No.	Supplier/Type of Service		January-06 (A) Estimated MCF Purchased @14.65	January-06 (B) Estimated Commodity Cost
1	**Estimated Purchases:**			
2	Texas Gas Area		1,079,620	$10,993,300.17
3	Tennessee Gas Area		394,682	3,974,415.12
4	Trunkline Gas Area		151,469	1,581,783.66
5	Midwestern Gas Area		0	0.00
6	Total Estimated Purchases		1,625,771	16,549,498.95
7				
8	**Transportation Costs:**			
9	Texas Gas Transmission			54,094.60
10	Tennessee Gas Pipeline			53,396.55
11	Trunkline Gas Area			2,293.29
11	Midwestern Gas Area			
12				
13	Local Production		13,578	135,333.48
14				
15	WKG End-User Cash Outs		4,289	34,944.74
16				
17	Total Current Month Gas Cost		1,643,637	$16,829,561.61
18				
19	Less: Lost & Unaccounted for @	1.38%	22,682	
20				
21	Total Deliveries		1,620,955	$16,829,561.61
22				
23	Estimated LVS Weighted Average Commodity Rate			**$10.3825**

Atmos Energy Corporation
Expected Purchases
LVS Commodity Purchase Basis
For the Period of February '06 to April '06

Line No.			(1) Mcf	(2) MMbtu	(3) Gas Cost
1	**Texas Gas Area**				
2	No Notice Service		5,908,390	6,056,100	44,504,462
3	Firm Transportation		88,780	91,000	666,848
4	Total Texas Gas Area		5,997,170	6,147,100	45,171,310
5					
6					
7	**Tennessee Gas Area**				
8	FT-A&G Commodity		724,030	752,991	5,643,667
9	FT-GS Commodity		131,437	136,694	1,093,661
10	Total Tennessee Gas Area		855,467	889,685	6,737,328
11					
12	**Trunkline Gas Area**				
13	Firm Transportation		88,889	92,000	1,185,789
14					
15					
16	**Local Production**				
17	Commodity		59,512	61,000	447,008
18					
19					
20	Expected WKG End-User Cash Outs		0	0	0
21					
22	**Total LVS Commodity Purchase Basis**		7,001,038	7,189,785	53,541,435
23					
24	Lost & Unaccounted for @	1.38%	96,614	99,219	
25					
26	Total Deliveries		6,904,424	7,090,566	53,541,435
27					
28	Estimated LVS Weighted Average Commodity Rate (per MMbtu)				$7.5511
29					
30	Estimated LVS Weighted Average Commodity Rate (per Mcf)				$7.7547
31	(To only be used to calculate commodity credit back on Exhibit B)				
32					
33					

ATMOS energy

RECEIVED

JUN 28 2006

PUBLIC SERVICE COMMISSION

June 26, 2006

Ms. Elizabeth O'Donnell, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602

Re: Case No. 2006-00 324

Dear Ms. O'Donnell:

We are filing the enclosed original and three (3) copies of a notice under the provisions of our Gas Cost Adjustment Clause, Case No. 2006-00324 **This filing contains a Petition of Confidentiality and confidential documents.**

Please indicate receipt of this filing by stamping and dating the enclosed duplicate of this letter and returning it in the self-addressed stamped envelope to the following address:

Atmos Energy Corporation
5430 LBJ Freeway, Suite 600
Dallas, TX 75240

If you have any questions, feel free to call me at 972-855-3011.

Sincerely,

Thomas J Morel

Thomas J. Morel
Senior Rate Analyst, Rate Administration

Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
JUN 28 2006
PUBLIC SERVICE COMMISSION

In the Matter of:

GAS COST ADJUSTMENT	)	**CASE NO.**
FILING OF	)	**2006 - 00**324
ATMOS ENERGY CORPORATION	)	

PETITION FOR CONFIDENTIALITY OF INFORMATION BEING FILED WITH THE KENTUCKY PUBLIC SERVICE COMMISSION

Atmos Energy Corporation ("Atmos") respectfully petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001 Section 7 and all other applicable law, for confidential treatment of the information which is described below and which is attached hereto. In support of this Petition, Atmos states as follows:

1. Atmos is filing its Gas Cost Adjustment ("GCA") for the quarterly period commencing on August 1, 2006. This GCA filing also contains Atmos' quarterly Correction Factor (CF) as well as information pertaining to Atmos' projected gas prices. The following two attachments contain information which require confidential treatment.

   a. The attached Exhibit D contains information from which the actual price being paid by Atmos for natural gas to its supplier can be determined.

   b. The attached Weighted Average Cost of Gas ("WACOG") schedule in support of Exhibit C, page 19 contains confidential information pertaining to prices projected to be paid by Atmos for purchase contracts.

2. Information of the type described above has previously been filed by Atmos with the Commission under petitions for confidentiality. Exhibit D contains information from which it

could be determined what Atmos is paying for natural gas under its gas supply agreement with its existing supplier. The Commission has consistently granted confidential protection to that type of information in each of the prior GCA filings in KPSC Case No. 1999-070. The information contained in the attached WACOG schedule has also been filed with the Commission under a Petition for Confidentiality in Case No. 97-513.

3. All of the information sought to be protected herein as confidential, if publicly disclosed, would have serious adverse consequences to Atmos and its customers. Public disclosure of this information would impose an unfair commercial disadvantage on Atmos. Atmos has successfully negotiated an extremely advantageous gas supply contract that is very beneficial to Atmos and its ratepayers. Detailed information concerning that contract, including commodity costs, demand and transportation charges, reservations fees, etc. on specifically identified pipelines, if made available to Atmos' competitors, (including specifically non-regulated gas marketers), would clearly put Atmos to an unfair commercial disadvantage. Those competitors for gas supply would be able to gain information that is otherwise confidential about Atmos' gas purchases and transportation costs and strategies. The Commission has accordingly granted confidential protection to such information.

4. Likewise, the information contained in the WACOG schedule in support of Exhibit C, page 19, also constitutes sensitive, proprietary information which if publicly disclosed would put Atmos to an unfair commercial disadvantage in future negotiations.

5. Atmos would not, as a matter of company policy, disclose any of the information for which confidential protection is sought herein to any person or entity, except as required by law or pursuant to a court order or subpoena. Atmos' internal practices and policies are directed towards non-disclosure of the attached information. In fact, the information contained in the

attached report is not disclosed to any personnel of Atmos except those who need to know in order to discharge their responsibility. Atmos has never disclosed such information publicly. This information is not customarily disclosed to the public and is generally recognized as confidential and proprietary in the industry.

6. There is no significant interest in public disclosure of the attached information. Any public interest in favor of disclosure of the information is out weighed by the competitive interest in keeping the information confidential.

7. The attached information is also entitled to confidential treatment because it constitutes a trade secret under the two prong test of KRS 265.880: (a) the economic value of the information as derived by not being readily ascertainable by other persons who might obtain economic value by its disclosure; and, (b) the information is the subject of efforts that are reasonable under the circumstances to maintain its secrecy. The economic value of the information is derived by Atmos maintaining the confidentiality of the information since competitors and entities with whom Atmos transacts business could obtain economic value by its disclosure.

8. Pursuant to 807 KAR 5:001 Section 7(3) temporary confidentiality of the attached information should be maintained until the Commission enters an order as to this petition. Once the order regarding confidentiality has been issued, Atmos would have twenty (20) days to seek alternative remedies pursuant to 807 KAR 5:001 Section 7(4).

WHEREFORE, Atmos petitions the Commission to treat as confidential all of the material and information which is included in the attached one volume marked "Confidential".

Respectfully submitted this 23rd day of June, 2006.

Mark R. Hutchinson
611 Frederica Street
Owensboro, Kentucky 42301

Douglas Walther
Atmos Energy Corporation
P.O. Box 650250
Dallas, Texas 75265

John N. Hughes
124 W. Todd Street
Frankfort, Kentucky 40601

Attorneys for Atmos Energy Corporation

RECEIVED

JUN 2 8 2006

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

GAS COST ADJUSTMENT	)	Case No. 2006 - 00324
FILING OF	)	
ATMOS ENERGY CORPORATION	)	

NOTICE

QUARTERLY FILING

For The Period

August 1, 2006 - October 31, 2006

Attorney for Applicant

Mark R. Hutchinson
1700 Frederica St.
Suite 201
Owensboro, Kentucky 42301

June 26, 2006

Atmos Energy Corporation, ("the Company"), is duly qualified under the laws of the Commonwealth of Kentucky to do its business. The Company is an operating public utility engaged in the business of purchasing, transporting and distributing natural gas to residential, commercial and industrial users in western and central Kentucky. The Company's principal operating office and place of business is 2401 New Hartford Road, Owensboro, Kentucky 42301. Correspondence and communications with respect to this notice should be directed to:

Gary L. Smith
Vice President - Marketing &
Regulatory Affairs/Kentucky Division
Atmos Energy Corporation
Post Office Box 866
Owensboro, Kentucky 42302

Mark R. Hutchinson
Attorney for Applicant
1700 Frederica St.
Suite 201
Owensboro, Kentucky 42301

Thomas J. Morel
Senior Rate Analyst, Rate Administration
Atmos Energy Corporation
5430 LBJ Freeway, Suite 600
Dallas, Texas 75240

The Company gives notice to the Kentucky Public Service Commission, hereinafter "the Commission", pursuant to the Gas Cost Adjustment Clause contained in the Company's settlement gas rate schedules in Case No. 99-070.

The Company hereby files Eighteenth Revised Sheet No. 4, Eighteenth Revised Sheet No. 5 and Eighteenth Revised Sheet No. 6 to its PSC No. 1, Rates, Rules and Regulations for Furnishing Natural Gas to become effective August 1, 2006.

The Gas Cost Adjustment (GCA) for firm sales service is $8.7180 per Mcf, $7.8447 per Mcf for high load factor firm sales service, and $7.8447 per Mcf for interruptible sales service. The supporting calculations for the Eighteenth Revised Sheet No. 5 are provided in the following Exhibits:

Exhibit A - Summary of Derivations of Gas Cost Adjustment (GCA) ....

Exhibit B - Expected Gas Cost (EGC) Calculation ....

Exhibit C - Rates used in the Expected Gas Cost (EGC) Calculation .....

Exhibit D - Correction Factor (CF) Calculation ....

Exhibit F - LVS Pricing Calculation ....

Since the Company's last GCA filing, Case No. 2006-00135, the following changes have occurred in its pipeline and gas supply commodity rates for the GCA period.

1. The commodity rates per MMbtu used are based on historical estimates and/or current data for the quarter August 2006 through October 2006, as shown in Exhibit C, page 19.

2. The Expected Commodity Gas Cost will be approximately $7.7975 MMbtu for the quarter August 2006 through October 2006, as compared to $7.9545 per MMbtu used for the quarter of May 2006 through July 2006.

3. The Company's notice sets out a new Correction Factor of ($0.1749) per Mcf, which will remain in effect until at least October 31, 2006.

The GCA tariff as approved in Case No. 92-558 provides for a Correction Factor (CF) which compensates for the difference between the expected gas cost and the actual gas cost for prior periods. A revision to the GCA tariff effective December 1, 2001, Filing No. T62-1253, provides that the Correction Factor be filed on a quarterly basis. The Company is filing its updated Correction Factor that is based upon the balance in the Company's Account 191 as of April 30, 2006. The calculation for the Correction Factor is shown on Exhibit D, Page 1.

WHEREFORE, Atmos Energy Corporation requests this Commission, pursuant to the Commission's order in Case No. 99-070, to approve the Gas Cost Adjustment (GCA) as filed in Eighteenth Revised Sheet No. 5; and Eighteenth Revised Sheet No. 6 setting out the General Transportation Tariff Rate T-2 for each respective sales rate for meter readings made on and after August 1, 2006.

DATED at Dallas Texas, this 26th Day of June, 2006.

ATMOS ENERGY CORPORATION

By: Thomas J Morel

Thomas J. Morel
Senior Rate Analyst, Rate Administration
Atmos Energy Corporation

ATMOS ENERGY CORPORATION

Current Rate Summary

Case No. 2006-00000

Firm Service

Base Charge:

Residential	-	$7.50	per meter per month
Non-Residential	-	20.00	per meter per month
Carriage (T-4)	-	220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

Rate per Mcf[2]			Sales (G-1)			Transport (T-2)			Carriage (T-4)			
First	300 [1]	Mcf	@	9.9080	per Mcf	@	2.2472	per Mcf	@	1.1900	per Mcf	(R, N, N)
Next	14,700 [1]	Mcf	@	9.3770	per Mcf	@	1.7162	per Mcf	@	0.6590	per Mcf	(R, N, N)
Over	15,000	Mcf	@	9.1480	per Mcf	@	1.4872	per Mcf	@	0.4300	per Mcf	(R, N, N)

High Load Factor Firm Service

HLF demand charge/Mcf	@	4.5576	@	4.5576	per Mcf of daily Contract Demand	(N)

Rate per Mcf[2]									
First	300 [1]	Mcf	@	9.0347	per Mcf	@	1.3739	per Mcf	(R, N)
Next	14,700 [1]	Mcf	@	8.5037	per Mcf	@	0.8429	per Mcf	(R, N)
Over	15,000	Mcf	@	8.2747	per Mcf	@	0.6139	per Mcf	(R, N)

Interruptible Service

Base Charge	-	$220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

Rate per Mcf[2]			Sales (G-2)			Transport (T-2)			Carriage (T-3)			
First	15,000 [1]	Mcf	@	8.3747	per Mcf	@	0.7139	per Mcf	@	0.5300	per Mcf	(R, N, N)
Over	15,000	Mcf	@	8.2038	per Mcf	@	0.5430	per Mcf	@	0.3591	per Mcf	(R, N, N)

[1] All gas consumed by the customer (sales, transportation, and carriage; firm, high load factor, and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] DSM, GRI and MLR Riders may also apply, where applicable.

ATMOS ENERGY CORPORATION

Current Gas Cost Adjustments

Case No. 2006-00000

Applicable

For all Mcf billed under General Sales Service (G-1) and Interruptible Sales Service (G-2).

Gas Charge = GCA

GCA = EGC + CF + RF + PBRRF

Gas Cost Adjustment Components	G - 1	HLF G - 1	G-2	
EGC (Expected Gas Cost Component)	8.8547	7.9814	7.9814	(R, R, R)
CF (Correction Factor)	(0.1749)	(0.1749)	(0.1749)	(R, R, R)
RF (Refund Adjustment)	(0.0017)	(0.0017)	(0.0017)	(N. N. N)
PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0399	(N, N, N)
GCA (Gas Cost Adjustment)	$8.7180	$7.8447	$7.8447	(R, R, R)

ISSUED: **June 26, 2006** **Effective:** **August 1, 2006**

(Issued by Authority of an Order of the Public Service Commission in Case No. 2006-00000.)

ISSUED BY: **Gary L. Smith** **Vice President - Marketing & Regulatory Affairs/Kentucky Division**

ATMOS ENERGY CORPORATION

Current Transportation and Carriage

Case No. 2006-00000

Case No. 2004-00398

The General Transportation Rate T-2 and Carriage Service (Rates T-3 and T-4) for each respective service net monthly rate is as follows:

System Lost and Unaccounted gas percentage: 1.38%

					Simple Margin		*Non-* Commodity		*Gross* Margin		
Transportation Service (T-2)[1]											
a)	Firm Service										
	First	300 [2]	Mcf	@	$1.1900	+	$1.0572	=	$2.2472	per Mcf	(N)
	Next	14,700 [2]	Mcf	@	0.6590	+	1.0572	=	1.7162	per Mcf	(N)
	All over	15,000	Mcf	@	0.4300	+	1.0572	=	1.4872	per Mcf	(N)
b)	High Load Factor Firm Service (HLF)										
	Demand			@	$0.0000	+	4.5576	=	$4.5576	per Mcf of daily contract demand	(N)
	First	300 [2]	Mcf	@	$1.1900	+	$0.1839	=	$1.3739	per Mcf	(N)
	Next	14,700 [2]	Mcf	@	0.6590	+	0.1839	=	0.8429	per Mcf	(N)
	All over	15,000	Mcf	@	0.4300	+	0.1839	=	0.6139	per Mcf	(N)
c)	Interruptible Service										
	First	15,000 [2]	Mcf	@	$0.5300	+	$0.1839	=	$0.7139	per Mcf	(N)
	All over	15,000	Mcf	@	0.3591	+	0.1839	=	0.5430	per Mcf	(N)
Carriage Service[3]											
	Firm Service (T-4)										
	First	300	[2] Mcf	@	$1.1900	+	$0.0000	=	$1.1900	per Mcf	(N)
	Next	14,700	[2] Mcf	@	0.6590	+	0.0000	=	0.6590	per Mcf	(N)
	All over	15,000	[2] Mcf	@	0.4300	+	0.0000	=	0.4300	per Mcf	(N)
	Interruptible Service (T-3)										
	First	15,000 [2]	Mcf	@	$0.5300	+	$0.0000	=	$0.5300	per Mcf	(N)
	All over	15,000	Mcf	@	0.3591	+	0.0000	=	0.3591	per Mcf	(N)

[1] Includes standby sales service under corresponding sales rates. GRI Rider may also apply.

[2] All gas consumed by the customer (Sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[3] Excludes standby sales service.

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Sales Service

Line No.	Description	Case No. 2006-00135 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	G-1			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 300 Mcf	1.1900	1.1900	0.0000
5	Next 14,700 Mcf	0.6590	0.6590	0.0000
6	Over 15,000 Mcf	0.4300	0.4300	0.0000
7				
8	Gas Cost Adjustment Components			
9	EGC (Expected Gas Cost):			
10	Commodity	7.9545	7.7975	(0.1570)
11	Demand	1.0572	1.0572	0.0000
12	Take-Or-Pay	0.0000	0.0000	0.0000
13	Transition Costs	0.0000	0.0000	0.0000
14	Total EGC	9.0117	8.8547	(0.1570)
15	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
16	CF (Correction Factor)	0.2988	(0.1749)	(0.4737)
17	RF (Refund Adjustment)	(0.0017)	(0.0017)	0.0000
18	PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0000
19	GCA (Gas Cost Adjustment)	9.3487	8.7180	(0.6307)
20	Total Billing Cost of Gas	9.3487	8.7180	(0.6307)
21				
22	Commodity Charge (GCA included):			
23	First 300 Mcf	10.5387	9.9080	(0.6307)
24	Next 14,700 Mcf	10.0077	9.3770	(0.6307)
25	Over 15,000 Mcf	9.7787	9.1480	(0.6307)
26				
27	HLF (High Load Factor)			
28				
29	Commodity Charge (Base Rate per Case No. 99-070):			
30	First 300 Mcf	1.1900	1.1900	0.0000
31	Next 14,700 Mcf	0.6590	0.6590	0.0000
32	Over 15,000 Mcf	0.4300	0.4300	0.0000
33				
34	Gas Cost Adjustment Components			
35	EGC (Expected Gas Cost):			
36	Commodity	7.9545	7.7975	(0.1570)
37	Demand	0.1839	0.1839	0.0000
38	Take-Or-Pay	0.0000	0.0000	0.0000
39	Transition Costs	0.0000	0.0000	0.0000
40	Total EGC	8.1384	7.9814	(0.1570)
41	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
42	CF (Correction Factor)	0.2988	(0.1749)	(0.4737)
43	RF (Refund Adjustment)	(0.0017)	(0.0017)	0.0000
44	PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0000
45	GCA (Gas Cost Adjustment)	8.4754	7.8447	(0.6307)
46	Total Cost of Gas to Bill (excludes MDQ Demand)	8.4754	7.8447	(0.6307)
47				
48	Commodity Charge (GCA included):			
49	First 300 Mcf	9.6654	9.0347	(0.6307)
50	Next 14,700 Mcf	9.1344	8.5037	(0.6307)
51	Over 15,000 Mcf	8.9054	8.2747	(0.6307)
52				
53	HLF Demand			
54	Contract Demand Factor	4.5576	4.5576	0.0000

Atmos Energy Corporation
Comparison of Current and Previous Cases
Interruptible Sales Service

Line No.	Description	Case No. 2006-00135 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	**G-2**			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 15,000 Mcf	0.5300	0.5300	0.0000
5	Over 15,000 Mcf	0.3591	0.3591	0.0000
6				
7	Gas Cost Adjustment Components			
8	Expected Gas Cost (EGC):			
9	Commodity	7.9545	7.7975	(0.1570)
10	Demand	0.1839	0.1839	0.0000
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0000	0.0000	0.0000
13	Total EGC	8.1384	7.9814	(0.1570)
14	Less: Base Cost of Gas (BCOG)	0.0000	0.0000	0.0000
15	Correction Factor (CF)	0.2988	(0.1749)	(0.4737)
16	Refund Adjustment (RF)	(0.0017)	(0.0017)	0.0000
17	Performance Based Rate Recovery Factor (PBRRF)	0.0399	0.0399	0.0000
18	Gas Cost Adjustment (GCA)	8.4754	7.8447	(0.6307)
19	Total Cost of Gas to Bill	8.4754	7.8447	(0.6307)
20				
21	Commodity Charge (GCA included):			
22	First 15,000 Mcf	9.0054	8.3747	(0.6307)
23	Over 15,000 Mcf	8.8345	8.2038	(0.6307)
24				
25				

Line No.	Monthly Refund Factor	Case No.	Effective Date	G - 1	G - 1 / HLF	G - 2
26						
27						
28						
29	1 -	1999-070 L	07/01/01	0.0000	0.0000	0.0000
30	2 -	1999-070 M	08/01/01	0.0000	0.0000	0.0000
31	3 -	1999-070 N	10/01/01	0.0000	0.0000	0.0000
32	4 -	1999-070 O	11/01/01	(0.0019)	(0.0019)	(0.0019)
33	5 -	1999-070 P	05/03/02	0.0000	0.0000	0.0000
34	6 -	2002-00251	08/01/02	(0.0095)	(0.0095)	(0.0019)
35	7 -	2002-00359	11/01/02	(0.1574)	(0.1574)	(0.0391)
36	8 -	2003-00377	11/01/03	(0.0006)	(0.0006)	(0.0006)
37	9 -	2004-00269	08/01/04	(0.0048)	(0.0048)	(0.0048)
38	10 -	2005-00399	11/01/05	(0.0017)	(0.0017)	(0.0017)
39	11 -					
40	12 -					
41						
42	Total Supplier Refund Adjustment (RF)			(0.0017)	(0.0017)	(0.0017)
43						

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description		Case No. 2006-00135	Case No. 2006-00000	Difference
			$/Mcf	$/Mcf	$/Mcf
1	T-2 \ G-1				
2					
3					
4	Simple Margin (Base Rate per Case No. 99-070):				
5	First	300 Mcf	1.1900	1.1900	0.0000
6	Next	14,700 Mcf	0.6590	0.6590	0.0000
7	Over	15,000 Mcf	0.4300	0.4300	0.0000
8					
9	Non-Commodity Components:				
10	Demand		1.0572	1.0572	0.0000
11	Take-Or-Pay		0.0000	0.0000	0.0000
12	Transition Costs		0.0000	0.0000	0.0000
13	RF (Refund Adjustment)		0.0000	0.0000	0.0000
14	Total		1.0572	1.0572	0.0000
15					
16	Gross Margin:				
17	First	300 Mcf	2.2472	2.2472	0.0000
18	Next	14,700 Mcf	1.7162	1.7162	0.0000
19	Over	15,000 Mcf	1.4872	1.4872	0.0000
20					
21	T-2\G-1\HLF				
22					
23	Simple Margin (Base Rate per Case No. 99-070):				
24	First	300 Mcf	1.1900	1.1900	0.0000
25	Next	14,700 Mcf	0.6590	0.6590	0.0000
26	Over	15,000 Mcf	0.4300	0.4300	0.0000
27					
28	Non-Commodity Components:				
29	Demand		0.1839	0.1839	0.0000
30	Take-Or-Pay		0.0000	0.0000	0.0000
31	Transition Costs		0.0000	0.0000	0.0000
32	RF (Refund Adjustment)		0.0000	0.0000	0.0000
33	Total		0.1839	0.1839	0.0000
34					
35	Gross Margin (Excluding HLF Demand):				
36	First	300 Mcf	1.3739	1.3739	0.0000
37	Next	14,700 Mcf	0.8429	0.8429	0.0000
38	Over	15,000 Mcf	0.6139	0.6139	0.0000
39					
40	HLF Demand				
41	Contract Demand Factor		4.5576	4.5576	0.0000
42					

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description			Case No. 2006-00135	Case No. 2006-00000	Difference
				$/Mcf	$/Mcf	$/Mcf
1	Carriage Service					
2						
3	Firm Service (T-4)					
4	Simple Margin (Base Rate per Case No. 99-070):					
5	First	300	Mcf	1.1900	1.1900	0.0000
6	Next	14,700	Mcf	0.6590	0.6590	0.0000
7	Over	15,000	Mcf	0.4300	0.4300	0.0000
8						
9	Non-Commodity Components:					
11	Take-Or-Pay			0.0000	0.0000	0.0000
13	RF (Refund Adjustment)			0.0000	0.0000	0.0000
14	Total			0.0000	0.0000	0.0000
15						
16	Gross Margin:					
17	First	300	Mcf	1.1900	1.1900	0.0000
18	Next	14,700	Mcf	0.6590	0.6590	0.0000
19	Over	15,000	Mcf	0.4300	0.4300	0.0000
20						

Comparison of Current and Previous Cases
Interruptible Transportation and Carriage Service

Line No.	Description			Case No. 2006-00135	2006-00000	Difference
				$/Mcf	$/Mcf	$/Mcf
1	**General Transporation (T-2)**					
2						
3	Interruptible Service (G-2)					
4	Simple Margin (Base Rate per Case No. 99-070):					
5	First	15,000	Mcf	0.5300	0.5300	0.0000
6	Over	15,000	Mcf	0.3591	0.3591	0.0000
7						
8	Non-Commodity Components:					
9	Demand			0.1839	0.1839	0.0000
10	Take-Or-Pay			0.0000	0.0000	0.0000
11	Transition Costs			0.0000	0.0000	0.0000
12	RF (Refund Adjustment)			0.0000	0.0000	0.0000
13	Total			0.1839	0.1839	0.0000
14						
15	Gross Margin:					
16	First	15,000	Mcf	0.7139	0.7139	0.0000
17	Over	15,000	Mcf	0.5430	0.5430	0.0000
18						
19	**Carriage Service**					
20						
21	Carriage Service (T-3)					
22	Simple Margin (Base Rate per Case No. 99-070):					
23	First	15,000	Mcf	0.5300	0.5300	0.0000
24	Over	15,000	Mcf	0.3591	0.3591	0.0000
25						
26	Non-Commodity Components:					
28	Take-Or-Pay			0.0000	0.0000	0.0000
30	RF (Refund Adjustment)			0.0000	0.0000	0.0000
31	Total			0.0000	0.0000	0.0000
32						
33	Gross Margin:					
34	First	15,000	Mcf	0.5300	0.5300	0.0000
35	Over	15,000	Mcf	0.3591	0.3591	0.0000
36						

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Texas Gas

				(1)	(2)	(3)	(4)	(5)
						Non-Commodity		
Line No.	Description		Tariff Sheet No.	Annual Units	Rate	Total	Demand	Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**SL to Zone 2**							
2	NNS Contract #	N0210		12,617,673				
3	Base Rate		20		0.3088	3,896,336	3,896,336	
4	GSR		20		0.0000	0		0
5	TCA Adjustment		20		0.0000	0	0	
6	Unrec TCA Surch		20		0.0000	0	0	
7	ISS Credit		20		0.0000	0	0	
8	Misc Rev Cr Adj		20		0.0000	0	0	
9	GRI		20		0.0000	0	0	
6								
7	Total SL to Zone 2			12,617,673		3,896,336	3,896,336	0
8								
9	**SL to Zone 3**							
10	NNS Contract #	N0340		27,480,375				
11	Base Rate		20		0.3543	9,736,297	9,736,297	
12	GSR		20		0.0000	0		0
13	TCA Adjustment		20		0.0000	0	0	
14	Unrec TCA Surch		20		0.0000	0	0	
15	ISS Credit		20		0.0000	0	0	
16	Misc Rev Cr Adj		20		0.0000	0	0	
17	GRI		20		0.0000	0	0	
18								
19	FT Contract #	3355		3,130,605				
20	Base Rate		24		0.2494	780,773	780,773	
21	GSR		24		0.0000	0		0
22	TCA Adjustment		24		0.0000	0	0	
23	Unrec TCA Surch		24		0.0000	0	0	
24	ISS Credit		24		0.0000	0	0	
25	Misc Rev Cr Adj		24		0.0000	0	0	
26	GRI		24		0.0000	0	0	
27								
28								
29	Total SL to Zone 3			30,610,980		10,517,070	10,517,070	0
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Texas Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**Zone 1 to Zone 3**							
2	FT Contract #	3355		2,344,395				
3	Base Rate		24		0.2194	514,360	514,360	
4	GSR		24		0.0000	0		0
5	TCA Adjustment		24		0.0000	0	0	
6	Unrec TCA Surch		24		0.0000	0	0	
7	ISS Credit		24		0.0000	0	0	
8	Misc Rev Cr Adj		24		0.0000	0	0	
9	GRI		24		0.0000	0	0	
6								
7	Total Zone 1 to Zone 3			2,344,395		514,360	514,360	0
8								
9	**SL to Zone 4**							
10	NNS Contract #	N0410		3,320,769				
11	Base Rate		20		0.4190	1,391,402	1,391,402	
12	GSR		20		0.0000	0		0
13	TCA Adjustment		20		0.0000	0	0	
14	Unrec TCA Surch		20		0.0000	0	0	
15	ISS Credit		20		0.0000	0	0	
16	Misc Rev Cr Adj		20		0.0000	0	0	
17	GRI		20		0.0000	0	0	
18								
19	FT Contract #	3819		1,277,500				
20	Base Rate		24		0.3142	401,391	401,391	
21	GSR		24		0.0000	0		0
22	TCA Adjustment		24		0.0000	0	0	
23	Unrec TCA Surch		24		0.0000	0	0	
24	ISS Credit		24		0.0000	0	0	
25	Misc Rev Cr Adj		24		0.0000	0	0	
26	GRI		24		0.0000	0	0	
27								
28	Total SL to Zone 4			4,598,269		1,792,793	1,792,793	0
29								
30	Total SL to Zone 2			12,617,673		3,896,336	3,896,336	0
31	Total SL to Zone 3			30,610,980		10,517,070	10,517,070	0
32	Total Zone 1 to Zone 3			2,344,395		514,360	514,360	0
33								
34	Total Texas Gas			50,171,317		16,720,559	16,720,559	0
35								
36								
37	Vendor Reservation Fees (Fixed)					0	0	
38								
39	TOP & Direct Billed Transition costs					0		
40								
41	Total Texas Gas Area Non-Commodity					16,720,559	16,720,559	0
42								
43								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Tennessee Gas

				(1)	(2)	(3)	(4)	(5)
						Non-Commodity		
Line No.	**Description**		**Tariff Sheet No.**	**Annual Units**	**Rate**	**Total**	**Demand**	**Transition Costs**
				MMbtu	$/MMbtu	$	$	$
1	**<u>0 to Zone 2</u>**							
2	FT-G Contract #	2546.1		12,844	9.0600			
3	Base Rate		23B		9.0600	116,367	116,367	
4	Settlement Surcharge		23B		0.0000	0		0
5	PCB Adjustment		23B		0.0000	0		0
6								
7	FT-G Contract #	2548.1		4,363	9.0600			
8	Base Rate		23B		9.0600	39,529	39,529	
9	Settlement Surcharge		23B		0.0000	0		0
10	PCB Adjustment		23B		0.0000	0		0
11								
12	FT-G Contract #	2550.1		5,739	9.0600			
13	Base Rate		23B		9.0600	51,995	51,995	
14	Settlement Surcharge		23B		0.0000	0		0
15	PCB Adjustment		23B		0.0000	0		0
16								
17	FT-G Contract #	2551.1		4,447	9.0600			
18	Base Rate		23B		9.0600	40,290	40,290	
19	Settlement Surcharge		23B		0.0000	0		0
20	PCB Adjustment		23B		0.0000	0		0
21								
22								
23	Total Zone 0 to 2			27,393		248,181	248,181	0
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Tennessee Gas

Line No.	Description	Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Total	(4) Non-Commodity Demand	(5) Transition Costs
			MMbtu	$/MMbtu	$	$	$
1	**1 to Zone 2**						
2	FT-G Contract # 2546		114,156	7.6200			
3	Base Rate	23B		7.6200	869,869	869,869	
4	Settlement Surcharge	23B		0.0000	0		0
5	PCB Adjustment	23B		0.0000	0		0
6							
7	FT-G Contract # 2548		44,997	7.6200			
8	Base Rate	23B		7.6200	342,877	342,877	
9	Settlement Surcharge	23B		0.0000	0		0
10	PCB Adjustment	23B		0.0000	0		0
11							
12	FT-G Contract # 2550		59,741	7.6200			
13	Base Rate	23B		7.6200	455,226	455,226	
14	Settlement Surcharge	23B		0.0000	0		0
15	PCB Adjustment	23B		0.0000	0		0
16							
17	FT-G Contract # 2551		45,058	7.6200			
18	Base Rate	23B		7.6200	343,342	343,342	
19	Settlement Surcharge	23B		0.0000	0		0
20	PCB Adjustment	23B		0.0000	0		0
21							
22	Total Zone 1 to 2		263,952		2,011,314	2,011,314	0
23							
24	Total Zone 0 to 2		27,393		248,181	248,181	0
25							
26	Total Zone 1 to 2 and Zone 0 to 2		291,345		2,259,495	2,259,495	0
27							
28	**Gas Storage**						
29	Production Area:						
30	Demand	27	34,968	2.0200	70,635	70,635	
31	Space Charge	27	4,916,148	0.0248	121,920	121,920	
32	Market Area:						
33	Demand	27	237,408	1.1500	273,019	273,019	
34	Space Charge	27	10,846,308	0.0185	200,657	200,657	
35	Total Storage				666,231	666,231	
36							
37	Vendor Reservation Fees (Fixed)				0	0	
38							
39	TOP & Direct Billed Transition costs				0	0	0
40							
41	Total Tennessee Gas Area FT-G Non-Commodity				2,925,726	2,925,726	0
42							
43							
44							
45							
46							
47							
48							
49							
50							
51							

Atmos Energy Corporation
Expected Gas Cost - Commodity
Purchases in Texas Gas Service Area

Line No.	Description	Tariff Sheet No.		Purchases (1) Mcf	(2) MMbtu	Rate (3) $/MMbtu	Total (4) $
1	No Notice Service				3,294,497		
2	Indexed Gas Cost (Texas Gas Payback)					7.2180	23,779,679
3	Commodity	20				0.0508	167,360
4	Fuel and Loss Retention @	36	2.15%			0.1586	522,507
5						7.4274	24,469,546
6							
7	Firm Transportation				91,000		
8	Indexed Gas Cost					7.2180	656,838
9	Base (Weighted on MDQs)	25				0.0439	3,995
10	TCA Adjustment	25				0.0000	0
11	Unrecovered TCA Surcharge	25				0.0000	0
12	Cash-out Adjustment	25				0.0000	0
13	GRI	25				0.0000	0
14	ACA	25				0.0018	164
15	Fuel and Loss Retention @	36	1.94%			0.1428	12,995
16						7.4065	673,992
17	No Notice Storage						
18	Net (Injections)/Withdrawals				(1,008,417)		
19	Indexed Gas Cost					7.2180	(7,278,754)
20	Commodity (Zone 3)	20				0.0508	(51,228)
21	Fuel and Loss Retention @	36	2.15%			0.1586	(159,935)
22						7.4274	(7,489,917)
23							
24							
25	Total Purchases in Texas Area				2,377,080	7.4266	17,653,621
26							
27							

Line No.	28 Used to allocate transportation non-commodity	Annualized MDQs in MMbtu	Allocation	Commodity Charge $/MMbtu		Weighted Average
29						
30						
31						
32	Texas Gas					
33	SL to Zone 2	12,617,673	25.15%	$0.0399	$	0.0100
34	SL to Zone 3	30,610,980	61.01%	0.0445		0.0271
35	1 to Zone 3	2,344,395	4.67%	0.0422		0.0020
36	SL to Zone 4	4,598,269	9.17%	0.0528		0.0048
37	Total	50,171,317	100.00%		$	0.0439
38						
39	Tennessee Gas					
40	0 to Zone 2	27,393	9.40%	0.0880	$	0.0083
41	1 to Zone 2	263,952	90.60%	0.0776		0.0703
42	Total	291,345	100.00%		$	0.0786
43						

Atmos Energy Corporation
Expected Gas Cost - Commodity
Purchases in Tennessee Gas Service Area

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	FT-A and FT-G				406,495		
2	Indexed Gas Cost					7.2180	2,934,081
3	Base Commodity (Weighted on MDQs)					0.0786	31,951
4	GRI	23C				0.0000	0
5	ACA	23C				0.0018	732
6	Transition Cost	23C				0.0000	0
7	Fuel and Loss Retention	29	3.69%			0.2765	112,396
8						7.5749	3,079,160
9							
10							
11	FT-GS				71,649		
12	Indexed Gas Cost					7.2180	517,162
13	Base Rate	20				0.5844	41,872
14	GRI	20				0.0000	0
15	ACA	20				0.0018	129
16	PCB Adjustment	20				0.0000	0
17	Settlement Surcharge	20				0.0000	0
18	Fuel and Loss Retention	29	3.69%			0.2765	19,811
19						8.0807	578,974
20							
21							
22	Gas Storage						
23	FT-A & FT-G Market Area (Injections)/Withdrawals				(188,675)		
24	Indexed Gas Cost/Storage					7.2180	(1,361,856)
25	Injection Rate	27				0.0102	(1,924)
26	Fuel and Loss Retention	27	1.49%			0.1092	(20,603)
27	Total					7.3374	(1,384,383)
28							
29							
30	FT-GS Market Area (Injections)/Withdrawals				(35,939)		
31	Indexed Gas Cost/Storage					7.2180	(259,408)
32	Injection Rate	27				0.0102	(367)
33	Fuel and Loss Retention	27	1.49%			0.1092	(3,925)
34	Total					7.3374	(263,700)
35							
36							
37	Total Tennessee Gas Zones				253,530	7.9283	2,010,051
38							
39							

Atmos Energy Corporation
Expected Gas Cost
Trunkline Gas

Commodity

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	Firm Transportation						
2	Expected Volumes				92,000		
3	Indexed Gas Cost					7.2180	664,056
4	Base Commodity					0.0213	1,960
5	GRI	10				-	0
6	ACA	10				0.0019	175
7	Fuel and Loss Retention	10	1.11%			0.0810	7,452
8						7.3222	673,643
9							
10							

Non-Commodity

Line No.	Description		(1) Tariff Sheet No.	(2) Annual Units MMbtu	(3) Non-Commodity Rate $/MMbtu	(4) Non-Commodity Total $	(5) Non-Commodity Demand $	(6) Transition Costs $
11	FT-G Contract #	014573		87,475				
12	Discount Rate on MDQs				7.2000	629,820	629,820	
13								
14				92,125				
15	GRI Surcharge		10			0	-	
16								
17	Reservation Fee					-	-	
18								
19	Total Trunkline Area Non-Commodity					629,820	629,820	
20								
21								

Atmos Energy Corporation
Demand Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Total Demand Cost:						
2	Texas Gas	$16,720,559					
3	Midwestern	0					
4	Tennessee Gas	2,925,726					
5	Trunkline	629,820					
6	Total	$20,276,105					
7							
8			Allocated	Related	Monthly Demand Charge		
9	Demand Cost Allocation:	Factors	Demand	Volumes	Firm	Interruptible	HLF
10	All	0.1850	$3,751,079	20,401,274	0.1839	0.1839	0.1839
11	Firm	0.8150	16,525,026	18,923,274	0.8733	NA	NA
12	Total	1.0000	$20,276,105		1.0572	0.1839	0.1839
13							
14			Volumetric Basis for				
15		Annualized	Monthly Demand Charge				
16		Mcf @14.65	All	Firm			
17	Firm Service						
18	Sales:						
19	G-1	18,887,274	18,887,274	18,887,274	1.0572		
20	HLF	60,000	60,000		0.1839 + HLF MDQ Demand		
21	LVS-1	0	0	0	1.0572		
22	Total Firm Sales	18,947,274	18,947,274	18,887,274			
23							
24	Transportation:						
25	T-2 \ G-1	36,000	36,000	36,000	1.0572		
26	HLF	0	0		0.1839		
27	Total Firm Service	18,983,274	18,983,274	18,923,274			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	684,000	684,000		1.0572	0.1839	
32	LVS-2	154,000	154,000		1.0572	0.1839	
33	Total Sales	838,000	838,000				
34							
35	Transportation:						
36	T-2 \ G-2	580,000	580,000		1.0572	0.1839	
37							
38	Total Interruptible Service	1,418,000	1,418,000				
39							
40	Carriage Service						
41	T-3 & T-4	23,438,000					
42							
43	Total	43,839,274	20,401,274	18,923,274			
44							
45	HLF MDQ Demand						
46	Firm Demand Cost		$16,525,026				
47	Peak Day Thru-put		302,152	Mcf/Peak Day			
48	Times:		12	Months/Year			
49	Total Annualized Peak Day Demand		3,625,824				
50	Demand Charge per MDQ		$4.5576	/ MDQ of Customer's Contract			
51							
52							
53	Note: LVS Credit =	($28,321)					

Atmos Energy Corporation
Take-or-Pay and Transition Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Other Fixed Charges	Take-or-Pay	Transition				
2	Texas Gas		$0				
3	Tennessee Gas		0				
4	Total	$0	$0				
5							
6							
7			Related	Charge			
8	Other Fixed Charges	Amount	Volumes	$/Mcf			
9	Take-or-Pay	0	43,839,274	0.0000			
10	Transition	0	20,401,274	0.0000			
11	Total	$0		0.0000			
12							
13							
14			Volumetric Basis for				
15		Annual	Other Fixed Charges			Other Fixed Charges	
16		Expected Mcf	Take-or-Pay	Transition		Take-or-Pay	Transition
17	Firm Service						
18	Sales:						
19	G-1	18,887,274	18,887,274	18,887,274			0.0000
20	HLF	60,000	60,000	60,000			0.0000
21	LVS-1	0	0	0			0.0000
22	Total Firm Sales	18,947,274	18,947,274	18,947,274			
23							
24	Transportation:						
25	T-2 \ G-1	36,000	36,000	36,000			0.0000
26	T-2 \ G-1 \ HLF	0					0.0000
27	Total Firm Service	18,983,274	18,983,274	18,983,274			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	684,000	684,000	684,000			0.0000
32	LVS-2	154,000	154,000	154,000			0.0000
33	Total Sales	838,000	838,000	838,000			
34							
35	Transportation:						
36	T-2 \ G-2	580,000	580,000	580,000			0.0000
37							
38	Total Interruptible Service	1,418,000	1,418,000	1,418,000			
39							
40	Carriage Service						
41	T-3 & T-4	23,438,000	23,438,000	NA			
42							
43	Total	43,839,274	43,839,274	20,401,274			
44							
45							
46	Note: LVS Credit =	$0					
47							

Atmos Energy Corporation
Expected Gas Cost - Commodity
Total System

Line No.	Description		(1) Purchases Mcf	(2) MMbtu	(3) Rate $/MMbtu	(4) Total $
1	**Texas Gas Area**					
2	No Notice Service		3,214,143	3,294,497	7.4274	24,469,546
3	Firm Transportation		88,780	91,000	7.4065	673,992
4	No Notice Storage		(983,821)	(1,008,417)	7.4274	(7,489,917)
5	Total Texas Gas Area		2,319,102	2,377,080	7.4266	17,653,621
6						
7	**Tennessee Gas Area**					
8	FT-A and FT-G		390,861	406,495	7.5749	3,079,160
9	FT-GS		68,893	71,649	8.0807	578,974
10	Gas Storage					
11	FT-A and FT-G Injections		(181,418)	(188,675)	7.3374	(1,384,383)
12	FT-GS Withdrawals		(34,557)	(35,939)	7.3374	(263,700)
13			243,779	253,530	7.9283	2,010,051
14	**Trunkline Gas Area**					
15	Firm Transportation		88,889	92,000	7.3222	673,643
16						
17						
18	**WKG System Storage**					
19	Injections		(759,590)	(778,580)	7.4274	(5,782,825)
20	Withdrawals		0	0	8.0100	0
21	Net WKG Storage		(759,590)	(778,580)	7.4274	(5,782,825)
22						
23						
24	Local Production		59,512	61,000	7.4065	451,797
25						
26						
27						
28	Total Commodity Purchases		1,951,692	2,005,030	7.4843	15,006,287
29						
30	Lost & Unaccounted for @	1.38%	26,933	27,669		
31						
32	Total Deliveries		1,924,759	1,977,361	7.5890	15,006,287
33						
34	LVS Commodity Credit to System					
35	LVS Sales		(50,000)	(51,366)	7.5526	(387,947)
36						
37						
38	Total Expected Commodity Cost		1,874,759	1,925,995	7.5900	14,618,340
39						
40	Expected Commodity Cost ($/Mcf)				7.7975	
41						
42						
43						

Atmos Energy Corporation
Load Factor Calculation for Demand Allocation

Line No.	Description	MCF	
	Annualized Volumes Subject to Demand Charges		
1	Sales Volume	19,631,274	
2	Large Volume Sales (Annualized)	154,000	
3	Transportation	616,000	
4	Total Mcf Billed Demand Charges	20,401,274	
5	Divided by: Days/Year	365	
7	Average Daily Sales and Transport Volumes	55,894	
8			
10	Peak Day Sales and Transportation Volume		
11	Estimated total company firm requirements for 5 degree average		
12	temperature day from Peak Day Book - with adjustments per rate filing	302,152	Mcf/Peak Day
13			
14			
15	New Load Factor (line 7 / line 12)	**0.1850**	

Seventh Revised Sheet No. 20 : Effective

Superseding: Substitute Sixth Revised Sheet No. 20

Currently Effective Maximum Transportation Rates ($ per MMBtu)
For Service Under Rate Schedule NNS

	Base Tariff Rates (1)	FERC ACA (2)	Currently Effective Rates (3)
Zone SL			
Daily Demand	0.1800		0.1800
Commodity	0.0253	0.0018	0.0271
Overrun	0.2053	0.0018	0.2071
Zone 1			
Daily Demand	0.2782		0.2782
Commodity	0.0431	0.0018	0.0449
Overrun	0.3213	0.0018	0.3231
Zone 2			
Daily Demand	0.3088		0.3088
Commodity	0.0460	0.0018	0.0478
Overrun	0.3548	0.0018	0.3566
Zone 3			
Daily Demand	0.3543		0.3543
Commodity	0.0490	0.0018	0.0508
Overrun	0.4033	0.0018	0.4051
Zone 4			
Daily Demand	0.4190		0.4190
Commodity	0.0614	0.0018	0.0632
Overrun	0.4804	0.0018	0.4822

Minimum Rate: Demand $-0-; Commodity -

Zone SL	0.0163
Zone 1	0.0186
Zone 2	0.0223
Zone 3	0.0262
Zone 4	0.0308

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental transportation charge of:

Daily Demand	$0.0621
Commodity	$0.0155
Overrun	$0.0776

This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Fifth Revised Sheet No. 24 : Effective

Superseding: Substitute Fourth Revised Sheet No. 24

Currently Effective Maximum Daily Demand Rates ($ per MMBtu)
For Service Under Rate Schedule FT

	Currently Effective Rates [1]
SL-SL	0.0794
SL-1	0.1552
SL-2	0.2120
SL-3	0.2494
SL-4	0.3142
1-1	0.1252
1-2	0.1820
1-3	0.2194
1-4	0.2842
2-2	0.1332
2-3	0.1705
2-4	0.2334
3-3	0.1181
3-4	0.1810
4-4	0.1374

Minimum Rates: Demand $-0-

Backhaul *rates equal fronthaul rates to zone of delivery.*

[1] Currently Effective Rates are equal to the Base Tariff Rates.

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental Daily Demand charge of $0.0621. This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Sixth Revised Sheet No. 25 : Effective

Superseding: Substitute Fifth Revised Sheet No. 25

Currently Effective Maximum Commodity Rates ($ per MMBtu)
For Service Under Rate Schedule FT

	Base Tariff Rates (1)	FERC ACA (2)	Currently Effective Rates (3)
SL-SL	0.0104	0.0018	0.0122
SL-1	0.0355	0.0018	0.0373
SL-2	0.0399	0.0018	0.0417
SL-3	0.0445	0.0018	0.0463
SL-4	0.0528	0.0018	0.0546
1-1	0.0337	0.0018	0.0355
1-2	0.0385	0.0018	0.0403
1-3	0.0422	0.0018	0.0440
1-4	0.0508	0.0018	0.0526
2-2	0.0323	0.0018	0.0341
2-3	0.0360	0.0018	0.0378
2-4	0.0446	0.0018	0.0464
3-3	0.0312	0.0018	0.0330
3-4	0.0398	0.0018	0.0416
4-4	0.0360	0.0018	0.0378

Minimum Rates: Commodity minimum base rates are presented on Sheet 31.

Backhaul rates equal fronthaul rates to zone of delivery.

Note: For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental Commodity charge of $0.0155. This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Third Revised Sheet No. 36 : Effective
Superseding: Second Revised Sheet No. 36

Schedule of Currently Effective Fuel Retention Percentages
Pursuant to Section 16 of the General Terms and Conditions

NNS/SGT/SNS RATE SCHEDULES

NNS/SGT WINTER

Delivery Zone	PFRP{1}	FAP{2}	EFRP{3}
SL	0.59%	0.41%	1.00%
1	2.54%	(0.18%)	2.36%
2	2.79%	(0.36%)	2.43%
3	3.07%	(0.34%)	2.73%
4	4.31%	(1.29%)	3.02%

NNS/SGT/SNS SUMMER

Delivery Zone	PFRP{1}	FAP{2}	EFRP{3}
SL	0.15%	(0.15%)	0.00%
1	2.21%	(0.29%)	1.92%
2	2.39%	(0.38%)	2.01%
3	2.63%	(0.48%)	2.15%
4	2.98%	(0.83%)	2.15%

FT/STF/STFX/IT/ITX RATE SCHEDULES

WINTER

Rec/Del Zone	PFRP	FAP	EFRP
SL/SL	0.28%	0.67%	0.95%
SL or 1/1	1.74%	(0.46%)	1.28%
SL or 1/2	2.12%	(0.20%)	1.92%
SL or 1/3	2.33%	0.51%	2.84%
SL or 1/4	2.98%	(0.08%)	2.90%
2/2	0.11%	0.35%	0.46%
2/3	0.21%	0.71%	0.92%
2/4	0.86%	0.12%	0.98%
3/3	0.11%	0.35%	0.46%
3/4	0.65%	0.00%	0.65%
4/4	0.33%	0.00%	0.33%

SUMMER

Rec/Del Zone	PFRP	FAP	EFRP
SL/SL	0.23%	0.73%	0.96%
SL or 1/1	1.50%	(0.44%)	1.06%
SL or 1/2	2.10%	(1.03%)	1.07%
SL or 1/3	2.13%	(0.19%)	1.94%
SL or 1/4	2.96%	(0.40%)	2.56%
2/2	0.01%	0.43%	0.44%
2/3	0.03%	0.84%	0.87%
2/4	0.86%	0.63%	1.49%
3/3	0.01%	0.43%	0.44%
3/4	0.83%	0.00%	0.83%
4/4	0.42%	0.00%	0.42%

FSS/ISS RATE SCHEDULES

Withdrawal

PFRP	FAP	EFRP
0.89%	0.35%	1.24%

Injection

PFRP	FAP	EFRP
0.72%	0.28%	1.00%

{1} Projected Fuel Retention Percentage
{2} Fuel Adjustment Percentage
{3} Effective Fuel Retention Percentage

Thirty-Second Revised Sheet No. 20 : Effective

Superseding: Thirty-First Revised Sheet No. 20

RATES PER DEKATHERM

FIRM TRANSPORTATION - GS RATES (FT-GS)

Base Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.2138		$0.4203	$0.5844	$0.6748	$0.7814	$0.8952	$1.0698
L		$0.1771						
1	$0.4318		$0.3268	$0.4951	$0.5849	$0.6915	$0.8052	$0.9804
2	$0.5844		$0.4951	$0.2000	$0.2897	$0.4144	$0.5106	$0.6852
3	$0.6748		$0.5849	$0.2897	$0.1489	$0.3995	$0.4951	$0.6698
4	$0.7995		$0.7096	$0.4144	$0.3995	$0.1886	$0.2311	$0.4061
5	$0.8952		$0.8052	$0.5106	$0.4951	$0.2311	$0.1989	$0.3466
6	$1.0698		$0.9804	$0.6852	$0.6698	$0.4061	$0.3466	$0.2374

Surcharges

DELIVERY ZONE

PCB Adjustment: 1/

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
L		$0.0000						
1	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
3	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
4	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
5	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
6	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Annual Charge Adjustment (ACA): $0.0018

Maximum Rates 2/, 3/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.2156		$0.4221	$0.5862	$0.6766	$0.7832	$0.8970	$1.0716
L		$0.1789						
1	$0.4336		$0.3286	$0.4969	$0.5867	$0.6933	$0.8070	$0.9822
2	$0.5862		$0.4969	$0.2018	$0.2915	$0.4162	$0.5124	$0.6870
3	$0.6766		$0.5867	$0.2915	$0.1507	$0.4013	$0.4969	$0.6716
4	$0.8013		$0.7114	$0.4162	$0.4013	$0.1904	$0.2329	$0.4079
5	$0.8970		$0.8070	$0.5124	$0.4969	$0.2329	$0.2007	$0.3484
6	$1.0716		$0.9822	$0.6870	$0.6716	$0.4079	$0.3484	$0.2392

Minimum Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Notes:

1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

3/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Seventeenth Revised Sheet No. 23A : Effective

Superseding: Sixteenth Revised Sheet No. 23A

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0457		$0.0687	$0.0898	$0.0996	$0.1136	$0.1249	$0.1626
L		$0.0304						
1	$0.0687		$0.0590	$0.0794	$0.0892	$0.1032	$0.1144	$0.1521
2	$0.0898		$0.0794	$0.0451	$0.0548	$0.0699	$0.0801	$0.1177

Tennessee Gas Pipeline

3	$0.0996	$0.0892	$0.0548	$0.0384	$0.0681	$0.0783	$0.1160
4	$0.1147	$0.1043	$0.0699	$0.0681	$0.0419	$0.0477	$0.0852
5	$0.1249	$0.1144	$0.0801	$0.0783	$0.0477	$0.0445	$0.0783
6	$0.1626	$0.1521	$0.1177	$0.1160	$0.0852	$0.0783	$0.0660

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0018

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Fourteenth Revised Sheet No. 23B : Effective

Superseding: Thirteenth Revised Sheet No. 23B

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-G

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
L		$0.00						
1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14

4	$12.53	$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09	$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59	$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-G Reservation Rate is $0.00 per Dth

Notes:

1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

Fifteenth Revised Sheet No. 23C : Effective

Superseding: Fourteenth Revised Sheet No. 23C

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-G

Base Commodity Rate

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0457		$0.0687	$0.0898	$0.0996	$0.1136	$0.1249	$0.1626
L		$0.0304						
1	$0.0687		$0.0590	$0.0794	$0.0892	$0.1032	$0.1144	$0.1521
2	$0.0898		$0.0794	$0.0451	$0.0548	$0.0699	$0.0801	$0.1177

3	$0.0996	$0.0892	$0.0548	$0.0384	$0.0681	$0.0783	$0.1160
4	$0.1147	$0.1043	$0.0699	$0.0681	$0.0419	$0.0477	$0.0852
5	$0.1249	$0.1144	$0.0801	$0.0783	$0.0477	$0.0445	$0.0783
6	$0.1626	$0.1521	$0.1177	$0.1160	$0.0852	$0.0783	$0.0660

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0018

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Fifteenth Revised Sheet No. 27 : Effective

Superseding: Fourteenth Revised Sheet No. 27

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	ADJUSTMENTS (TCSM)	ADJUSTMENTS (PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA						
Deliverability Rate	$2.02			$0.00	$2.02	
Space Rate	$0.0248			$0.0000	$0.0248	1.49%
Injection Rate	$0.0053				$0.0053	
Withdrawal Rate	$0.0053				$0.0053	
Overrun Rate	$0.2427				$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA						
Deliverability Rate	$1.15			$0.00	$1.15	
Space Rate	$0.0185			$0.0000	$0.0185	1.49%
Injection Rate	$0.0102				$0.0102	
Withdrawal Rate	$0.0102				$0.0102	
Overrun Rate	$0.1380				$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA						
Space Rate	$0.0848			$0.0000	$0.0848	1.49%
Injection Rate	$0.0102				$0.0102	
Withdrawal Rate	$0.0102				$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA						
Space Rate	$0.0993			$0.0000	$0.0993	1.49%
Injection Rate	$0.0053				$0.0053	
Withdrawal Rate	$0.0053				$0.0053	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

Excess Withdrawal Rate	$0.7800	$0.0019		$0.7819	
SS-NE					

Deliverability	$6.71		$0.00	$6.71	
Space Rate	$0.0132		$0.0000	$0.0132	3.25%
Injection Rate	$0.0102			$0.0102	
Withdrawal Rate	$0.0936			$0.0936	
Excess Withdrawal Rate	$1.1600	$0.0019		$1.1619	

1/ The quantity of gas associated with losses is 0.5%.
2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

First Revised Sheet No. 29 : Effective
Superseding: Substitute Original Sheet No. 29

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\, 3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interuptible Transportation-X, (FT-G) Firm Transportation-G, (EDS/ERS) FT- A Extended Transportation Service.

Ninth Revised Sheet No. 10 : Effective

Superseding: Eighth Revised Sheet No. 10

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

	Base Rate Per Dt	Adjustments Sec. 24	Adjustments Sec. 25	*Maximum* Rate Per Dt	*Minimum* Rate Per Dt	Fuel Reimbursement
	(1)	(2)	(3)	(4)	(5)	(6)
RATE SCHEDULE FT						
Field Zone to Zone 2						
- Reservation Rate	$ 9.7097	-	$ 0.2800	$ 9.9897	-	-
- Usage Rate (1)	0.0141	-	-	0.0141	$ 0.0141	2.25% (2)
- Overrun Rate (3)	0.3192	-	0.0092	0.3284	-	-
Zone 1A to Zone 2						
- Reservation Rate	$ 6.0096	-	$ 0.1900	$ 6.1996	-	-
- Usage Rate (1)	0.0117	-	-	0.0117	$ 0.0117	1.86% (2)
- Overrun Rate (3)	0.1976	-	0.0062	0.2038	-	-
Zone 1B to Zone 2						
- Reservation Rate	$ 4.5557	-	$ 0.1900	$ 4.7457	-	-
- Usage Rate (1)	0.0062	-	-	0.0062	$ 0.0062	0.86% (2)
- Overrun Rate (3)	0.1498	-	0.0062	0.1560	-	-
Zone 2 Only						
- Reservation Rate	$ 3.4350	-	$ 0.1900	$ 3.6250	-	-
- Usage Rate (1)	0.0011	-	-	0.0011	$ 0.0011	0.60% (2)
- Overrun Rate (3)	0.1129	-	0.0062	0.1191	-	-
Field Zone to Zone 1B						
- Reservation Rate	$ 8.4890	-	$ 0.2800	$ 8.7690	-	-
- Usage Rate (1)	0.0130	-	-	0.0130	$ 0.0130	1.95% (2)
- Overrun Rate (3)	0.2791	-	0.0092	0.2883	-	-
Zone 1A to Zone 1B						
- Reservation Rate	$ 4.7889	-	$ 0.1900	$ 4.9789	-	-
- Usage Rate (1)	0.0106	-	-	0.0106	$ 0.0106	1.56% (2)
- Overrun Rate (3)	0.1574	-	0.0062	0.1636	-	-
Zone 1B Only						
- Reservation Rate	$ 3.3350	-	$ 0.1900	$ 3.5250	-	-
- Usage Rate (1)	0.0051	-	-	0.0051	$ 0.0051	0.56% (2)
- Overrun Rate (3)	0.1096	-	0.0062	0.1158	-	-
Field Zone to Zone 1A						
- Reservation Rate	$ 7.3683	-	$ 0.2800	$ 7.6483	-	-

Trunkline

- Usage Rate (1)	0.0079	-	-	0.0079	$ 0.0079	1.69% 2)
- Overrun Rate (3)	0.2422	-	0.0092	0.2514	-	-
Zone 1A Only						
- Reservation Rate	$ 3.6682	-	$ 0.1900	$ 3.8582	-	-
- Usage Rate (1)	0.0055	-	-	0.0055	$ 0.0055	1.30% (2)
- Overrun Rate (3)	0.1206	-	0.0062	0.1268	-	-
Field Zone Only						
- Reservation Rate	$ 3.7001	-	$ 0.0900	$ 3.7901	-	-
- Usage Rate (1)	0.0024	-	-	0.0024	$ 0.0024	0.69% (2)
- Overrun Rate (3)	0.1216	-	0.0030	0.1246	-	-
Gathering Charge (All Zones)						
- Reservation Rate	$ 0.3257			$ 0.3257		
- Overrun Rate (3)	0.0107			0.0107		

(1) Excludes Section 21 Annual Charge Adjustment: $0.0018
(2) Fuel reimbursement for backhauls is 0.41%
(3) Maximum firm volumetric rate applicable for capacity release

Atmos Energy Corporation
Basis for Indexed Gas Cost
For the Quarter of August 2006 - October 2006
2006-00000

The projected commodity price was provided by the Gas Supply Department and was based upon the following:

A. The Gas Supply Department reviewed the NYMEX futures close prices for the quarter of August 2006 - October 2006 during the period June 13, 2006 through June 21, 2006 which are listed below:

		AUG 2006 ($/MMBTU)	SEP 2006 ($/MMBTU)	OCT 2006 ($/MMBTU)
Tuesday	13-Jun	6.438	6.750	7.130
Wednesday	14-Jun	6.852	7.112	7.467
Thursday	15-Jun	7.475	7.735	8.075
Friday	16-Jun	7.455	7.750	8.130
Monday	19-Jun	7.153	7.458	7.838
Tuesday	20-Jun	6.737	6.997	7.367
Wednesday	21-Jun	6.798	7.018	7.383
		$6.987	$7.260	$7.627

B. Gas Supply believes prices will remain stable and prices for the quarter of May 2006 - July 2006 will settle at 7.218 per Mmbtu for the period that the GCA is to be effective.

In support of Item B, a worksheet entitled "Estimated Weighted Average Cost of Gas" has been filed under a Petition for Confidentiality in this Case.

Atmos Energy Corporation
Kentucky Division
For the Month of May, 2006

For Kentucky customers served in:			Indexed 1 Cash-out Price		Transport Charge 2, 3		WKG Cash-out Price
A. Texas Gas:							
	Zone 2 Area	100% of Index Price	$6.2890	+	$0.0478	=	$6.3368
		90% of Index Price	5.6601	+	0.0478	=	5.7079
		80% of Index Price	5.0312	+	0.0478	=	5.0790
	Zone 3 Area	100% of Index Price	$6.2890	+	$0.0508	=	$6.3398
		90% of Index Price	5.6601	+	0.0508	=	5.7109
		80% of Index Price	5.0312	+	0.0508	=	5.0820
	Zone 4 Area	100% of Index Price	$6.2890	+	$0.0632	=	$6.3522
		90% of Index Price	5.6601	+	0.0632	=	5.7233
		80% of Index Price	5.0312	+	0.0632	=	5.0944
B. Tennessee Gas:							
	Zone 2 Area	100% of Index Price	$6.2354	+	$0.0916	=	$6.3270
		90% of Index Price	5.6119	+	0.0916	=	5.7035
		80% of Index Price	4.9883	+	0.0916	=	5.0799

[1] Indexed cash-out price is from the pipeline's Electronic Bulletin Board.

[2] Transport charge used for Texas Gas is its tariff sheet no. 20 commodity rate.

[3] Transport charge used for Tennessee Gas is its tariff sheet no. 23A maximum commodity rate from zone 0 to zone 2.

Atmos Energy Corporation
Estimated Weighted Average Cost of Gas
August-06 Through October-06

	August-06			September-06			October-06			Total		
	Volumes	Rate	Value	Volumes	Rate	Value	Volumes	Rate	Value	Volumes	Rate	Value
Texas Gas												
Trunkline												
Tennessee Gas												
TX Gas Storage												
TN Gas Storage												
WKG Storage												
Midwestern												

(This information has been filed under a Petition for Confidentiality)

WACOGs												

PUBLIC DISCLOSURE

Atmos Energy Corporation
Correction Factor (CF)
For the Three Months Ended April 1, 2006
Case No. 2006-000

Exhibit D
Page 1 of 5

Line No.	(1) Month	(2) Actual Sales Volume (Mcf)	(3) Recoverable Gas Cost	(4) Actual Recovered Gas Cost	(5) Under (Over) Recovery Amount	(6) Adjustments	(7) Total
1	February-06	3,007,431	21,039,072.92	33,845,219.57	(12,806,146.65)	0.00	(12,806,146.65)
2							
3	March-06	2,057,703	18,279,742.57	31,281,518.82	(13,001,776.25)	0.00	(13,001,776.25)
4							
5	April-06	852,289	5,462,763.72	18,314,769.49	(12,852,005.77)	0.00	(12,852,005.77)
6							
7							
8							
9							
10							
11							
12							
13	Total Gas Cost						
14	Under/(Over) Recovery		44,781,579.21	83,441,507.88	(38,659,928.67)	0.00	(38,659,928.67)
15							
16							
17							
18	Account 191 Balance @ January, 2006						$5,671,850.48
19	Elimination of Unbilled Gas Cost Balance @ December, 2006						27,725,906.00
20	Total Gas Cost Under/(Over) Recovery for the three months ended April, 2006						(38,659,928.67)
21	Recovery from outstanding Correction Factor (CF)						1,941,775.42
22	Account 191 Balance @ April, 2006						(3,320,396.77)
23							
24							
25							
26							
27							
28	Derivation of Correction Factor (CF):						
29							
30	Account 191 Balance					($3,320,397)	
31	Divided By: Total Expected Customer Sales					18,983,274	MCF
32							
33	**Correction Factor (CF)**					**($0.1749)**	**/MCF**
34							
35							

Atmos Energy Corporation
Recoverable Gas Cost Calculation
For the Three Months Ended April 1, 2006
Case No. 2006-000

Line No.	Description	Unit	GL Mar-06 (1) Month February-06	Apr-06 (2) March-06	May-06 (3) April-06	Source Document
1	**Supply Volume**					
2	Pipelines:					
3	Texas Gas Transmission [1]	Mcf	0	0	0	
4	Tennessee Gas Pipeline [1]	Mcf	0	0	0	
5	Trunkline Gas Company [1]	Mcf	0	0	0	
6	Midwestern Pipeline [1]	Mcf	0	0	0	
7	**Total Pipeline Supply**	Mcf	0	0	0	
8	Total Other Suppliers	Mcf	500,366	409,704	3,226,865	pages 5
9	Off System Storage					
10	Texas Gas Transmission	Mcf	0	0	0	
11	Tennessee Gas Pipeline	Mcf	422,054	170,256	(261,828)	
12	System Storage					
13	Withdrawals	Mcf	986,417	567,594	45,494	
14	Injections	Mcf	0	0	(677,848)	
15	Producers	Mcf	30,917	11,236	12,331	
16	Pipeline Imbalances cashed out	Mcf	0	0	0	
17	System Imbalances [2]	Mcf	1,067,677	898,913	(1,492,725)	
18	**Total Supply**	Mcf	3,007,431	2,057,703	852,289	
19						
20	Change in Unbilled	Mcf				
21	Company Use	Mcf	0	0	0	
22	Unaccounted For	Mcf	0	0	0	
23	**Total Sales**	Mcf	3,007,431	2,057,703	852,289	

[1] Includes settlement of historical imbalances and prepaid items.

[2] Includes Texas Gas No-Notice Service volumes and monthly imbalances related to transportation customer activities.

Atmos Energy Corporation
Recoverable Gas Cost Calculation
For the Three Months Ended April 1, 2006
Case No. 2006-000

Line No.	Description	GL Unit	Mar-06 (1) February-06	Apr-06 (2) Month March-06	May-06 (3) April-06	Source Document
1	**Supply Cost**					
2	Pipelines:					
3	Texas Gas Transmission [1]	$	1,565,349	1,716,998	1,518,781	
4	Tennessee Gas Pipeline [1]	$	313,395	331,651	326,586	
5	Trunkline Gas Company [1]	$	28,538	30,900	7,644	
6	Midwestern Pipeline [1]	$	0	0	0	
7	**Total Pipeline Supply**	$	1,907,281	2,079,549	1,853,010	
8	Total Other Suppliers	$	4,029,629	2,855,336	23,154,145	page 5
9	Hedging Settlements		0	0	0	
10	Off System Storage					
11	Texas Gas Transmission	$	0	0	0	
12	Tennessee Gas Pipeline	$	3,514,015	1,429,560	(1,869,915)	
13	WKG Storage		122,500	122,500	122,500	
14	System Storage					
15	Withdrawals	$	8,427,409	4,877,054	413,804	
16	Injections	$	0	0	(4,852,219)	
17	Producers	$	80,338	76,789	87,603	
18	Pipeline Imbalances cashed out	$	0	0	0	
19	System Imbalances [2]	$	2,957,900	6,838,954	(13,446,164)	
20	**Sub-Total**	$	21,039,073	18,279,743	5,462,764	
21						
22	Change in Unbilled	$				
23	Company Use	$	0	0	0	
24	Recovered thru Transportation	$	0	0	0	
25	**Total Recoverable Gas Cost**	$	21,039,073	18,279,743	5,462,764	

[1] Includes demand charges, cost of settlement of historical imbalances and prepaid items.

[2] Includes Texas Gas No-Notice Service volumes and monthly imbalances related to transportation customer activities.

Atmos Energy Corporation
Recovery from Correction Factors (CF)
For the Three Months Ended April, 2006
Case No. 2006-000

Exhibit D
Page 4 of 5

Line No.	Month	Type of Sales	Mcf Sold	Rate	Amount
1	February-06	G-1 Sales	2,604,089.2	$0.2988	$778,101.85
2		G-1 HLF	0.0	0.2988	0.00
3		G-2 Sales	43,536.8	0.2988	13,008.80
4		T-3 Overrun Sales	1,646.0	0.3287	541.04
5		T-4 Overrun Sales	7,451.0	0.3287	2,449.14
6		LVS-1 Sales	0.0	0.0000	0.00
7		LVS-2 Sales	8,301.0	0.0000	0.00
8		LVS HLF Sales	0.0	0.0000	0.00
9		Total	2,665,024.0		794,100.83
10					
11	March-06	G-1 Sales	2,419,979.4	$0.2988	$723,089.85
12		G-1 HLF	0.0	0.2988	0.00
13		G-2 Sales	34,065.0	0.2988	10,178.62
14		T-3 Overrun Sales	92.0	0.3287	30.24
15		T-4 Overrun Sales	243.0	0.3287	79.87
16		LVS-1 Sales	0.0	0.0000	0.00
17		LVS-2 Sales	7,632.0	0.0000	0.00
18		LVS HLF Sales	0.0	0.0000	0.00
19		Total	2,462,011.4		733,378.58
20					
21	April-06	G-1 Sales	1,370,450.7	$0.2988	$409,490.66
22		G-1 HLF	0.0	0.2988	0.00
23		G-2 Sales	16,093.2	0.2988	4,808.64
24		T-3 Overrun Sales	0.0	0.3287	0.00
25		T-4 Overrun Sales	(10.0)	0.3287	(3.29)
26		LVS-1 Sales	0.0	0.0000	0.00
27		LVS-2 Sales	8,562.0	0.0000	0.00
28		LVS HLF Sales	0.0	0.0000	0.00
29		Total	1,395,095.8		414,296.01
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	Total Recovery from Correction Factor (CF)				$1,941,775.42
51					

52 LVS sales commodity is "trued-up" according to Section 3(f) in LVS tariff in P.S.C. No. 1.

53

54 When Carriage (T-3 and T-4) customers have a positive imbalance that has been approved by the
55 Company, the customer is billed for the imbalance volumes at a rate equal to 110% of the Company's
56 applicable sales rate according to Section 6(a) of P.S.C. No. 20, Sheet Nos. 41A and 47A.

Atmos Energy Corporation
Detail Sheet for Supply Volumes & Costs
Traditional and Other Pipelines

Exhibit D
Page 5 of 5

		February, 2006		March, 2006		April, 2006	
	Description	MCF	Cost	MCF	Cost	MCF	Cost
1	**Texas Gas Pipeline Area**						
2	LG&E Natural						
3	Atmos Energy Marketing, LLC						
4	Texaco Gas Marketing						
5	CMS						
6	WESCO						
7	Southern Energy Company						
8	Union Pacific Fuels						
9	Atmos Energy Marketing, LLC						
10	Engage						
11	ERI						
12	Prepaid						
13	Reservation						
14	Hedging Costs - All Zones						
15							
16	**Total**	390,931	$3,137,273.22	194,902	$1,346,894.61	2,800,825	$20,087,462.55
17							
18							
19	**Tennessee Gas Pipeline Area**						
20	Atmos Energy Marketing, LLC						
21	Union Pacific Fuels						
22	WESCO						
23	Prepaid						
24	Reservation						
25	Fuel Adjustment						
26							
27	**Total**	0	$0.00	140,959	$985,994.23	396,968	$2,854,370.32
28							
29							
30	**Trunkline Gas Company**						
31	Atmos Energy Marketing, LLC						
32	Engage						
33	Prepaid						
34	Reservation						
35	Fuel Adjustment						
36							
37	**Total**	109,632	$894,072.37	75,710	$535,515.46	29,072	$212,312.17
38							
39							
40	**Midwestern Pipeline**						
41	Atmos Energy Marketing, LLC						
42	LG&E Natural						
43	Anadarko						
44	Prepaid						
45	Reservation						
46	Fuel Adjustment						
47							
48	**Total**	(197)	($1,716.31)	(1,867)	($13,067.91)	0	$0.00
49							
50							
51	**All Zones**						
52	Total	500,366	$4,029,629.28	409,704	$2,855,336.39	3,226,865	$23,154,145.04
53							
54							
55							

**** Detail of Volumes and Prices Has Been Filed Under Petition for Confidentiality ****

PUBLIC DISCLOSURE

ATMOS ENERGY CORPORATION
Large Volume Sales
For the Period May, 2006

Exhibit F
Page 1 of 3

The net monthly rates for Large Volume Sales service is as follows:

Base Charge:

LVS-1 Service	$ 20.00	per Meter
LVS-2 Service	220.00	per Meter
Combined Service	220.00	per Meter

LVS-1:

Firm Service			Simple Margin		Non-Commodity Component [2]		Estimated Weighted Average Commodity Gas Cost		Sales Rate	
First	300 [1]	Mcf @	$ 1.1900	+	$ 1.0572	+	$ 7.3101	=	$ 9.5573	per Mcf
Next	14,700 [1]	Mcf @	0.6590	+	1.0572	+	7.3101	=	9.0263	per Mcf
All over	15,000	Mcf @	0.4300	+	1.0572	+	7.3101	=	8.7973	per Mcf
High Load Factor Firm Service										
Demand				@	4.5576	+	$0.0000	=	$ 4.5576	per Mcf of daily contract demand
First	300 [1]	Mcf @	$ 1.1900	+	$ 0.1839	+	$ 7.3101	=	$ 8.6840	per Mcf
Next	14,700 [1]	Mcf @	0.6590	+	0.1839	+	7.3101	=	8.1530	per Mcf
All over	15,000	Mcf @	0.4300	+	0.1839	+	7.3101	=	7.9240	per Mcf

LVS-2:

Interruptible Service										
First	15,000	Mcf @	$ 0.5300	+	$ 0.1839	+	$ 7.3101	=	$ 8.0240	per Mcf
All over	15,000	Mcf @	0.3591	+	0.1839	+	7.3101	=	7.8531	per Mcf

True-up Adjustment for 4/06 billing period: $ 0.0694 per Mcf

[1] All gas consumed by the customer will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] The Non-Commodity Component is from P.S.C. No. 20 Seventeenth Revised Sheet No. 6, effective May 1,2006.

Atmos Energy Corporation
Large Volume Sales
Estimated WACOG used for Billing
For the Period May, 2006

Line No.	Supplier/Type of Service		April-06 (A) Estimated MCF Purchased @14.65	April-06 (B) Estimated Commodity Cost
1	**Estimated Purchases:**			
2	Texas Gas Area		2,800,825	$20,087,462.55
3	Tennessee Gas Area		396,968	2,851,941.92
4	Trunkline Gas Area		29,072	212,312.17
5	Midwestern Gas Area		0	0.00
6	Total Estimated Purchases		3,226,865	23,151,716.64
7				
8	**Transportation Costs:**			
9	Texas Gas Transmission			62,381.75
10	Tennessee Gas Pipeline			59,498.23
11	Trunkline Gas Area			444.00
11	Midwestern Gas Area			
12				
13	Local Production		12,331	87,602.61
14				
15	WKG End-User Cash Outs		9,434	58,537.23
16				
17	Total Current Month Gas Cost		3,248,629	$23,420,180.46
18				
19	Less: Lost & Unaccounted for @	1.38%	44,831	
20				
21	Total Deliveries		3,203,798	$23,420,180.46
22				
23	Estimated LVS Weighted Average Commodity Rate			**$7.3101**

Atmos Energy Corporation
Expected Purchases
LVS Commodity Purchase Basis
For the Period of May '06 to July '06

Line No.			(1) Mcf	(2) MMbtu	(3) Gas Cost
1	**Texas Gas Area**				
2	No Notice Service		3,214,143	3,294,497	24,388,831
3	Firm Transportation		88,780	91,000	671,762
4	Total Texas Gas Area		3,302,923	3,385,497	25,060,593
5					
6					
7	**Tennessee Gas Area**				
8	FT-A&G Commodity		390,861	406,495	3,069,038
9	FT-GS Commodity		68,893	71,649	577,190
10	Total Tennessee Gas Area		459,754	478,144	3,646,228
11					
12	**Trunkline Gas Area**				
13	Firm Transportation		88,889	92,000	683,505
14					
15					
16	**Local Production**				
17	Commodity		59,512	61,000	450,302
18					
19					
20	Expected WKG End-User Cash Outs		0	0	0
21					
22	**Total LVS Commodity Purchase Basis**		3,911,078	4,016,641	29,840,628
23					
24	Lost & Unaccounted for @	1.38%	53,973	55,430	
25					
26	Total Deliveries		3,857,105	3,961,211	29,840,628
27					
28	Estimated LVS Weighted Average Commodity Rate (per MMbtu)				$7.5332
29					
30	Estimated LVS Weighted Average Commodity Rate (per Mcf)				$7.7365
31	(To only be used to calculate commodity credit back on Exhibit B)				
32					
33					

ATMOS energy

September 28, 2006

RECEIVED

SEP 29 2006

PUBLIC SERVICE COMMISSION

Ms. Elizabeth O'Donnell, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602

Re: Case No. 2006-00428

Dear Ms. O'Donnell:

We are filing the enclosed original and three (3) copies of a notice under the provisions of our Gas Cost Adjustment Clause, Case No. 2006-428. **This filing contains a Petition of Confidentiality and confidential documents.**

Please indicate receipt of this filing by stamping and dating the enclosed duplicate of this letter and returning it in the self-addressed stamped envelope to the following address:

Atmos Energy Corporation
5430 LBJ Freeway, Suite 600
Dallas, TX 75240

If you have any questions, feel free to call me at 972-855-3011.

Sincerely,

Thomas J Morel

Thomas J. Morel
Senior Rate Analyst, Rate Administration

Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
SEP 28 2006
PUBLIC SERVICE COMMISSION

In the Matter of:

GAS COST ADJUSTMENT	)	**Case No. 2006** - 00478
FILING OF	)	
ATMOS ENERGY CORPORATION	)	

NOTICE

QUARTERLY FILING

For The Period

November 1, 2006 - January 31, 2007

Attorney for Applicant

Mark R. Hutchinson
1700 Frederica St.
Suite 201
Owensboro, Kentucky 42301

September 28, 2006

Atmos Energy Corporation, ("the Company"), is duly qualified under the laws of the Commonwealth of Kentucky to do its business. The Company is an operating public utility engaged in the business of purchasing, transporting and distributing natural gas to residential, commercial and industrial users in western and central Kentucky. The Company's principal operating office and place of business is 2401 New Hartford Road, Owensboro, Kentucky 42301. Correspondence and communications with respect to this notice should be directed to:

Gary L. Smith
Vice President - Marketing &
Regulatory Affairs/Kentucky Division
Atmos Energy Corporation
Post Office Box 866
Owensboro, Kentucky 42302

Mark R. Hutchinson
Attorney for Applicant
1700 Frederica St.
Suite 201
Owensboro, Kentucky 42301

Thomas J. Morel
Senior Rate Analyst, Rate Administration
Atmos Energy Corporation
5430 LBJ Freeway, Suite 600
Dallas, Texas 75240

The Company gives notice to the Kentucky Public Service Commission, hereinafter "the Commission", pursuant to the Gas Cost Adjustment Clause contained in the Company's settlement gas rate schedules in Case No. 99-070.

The Company hereby files Nineteenth Revised Sheet No. 4, Nineteenth Revised Sheet No. 5 and Nineteenth Revised Sheet No. 6 to its PSC No. 1, Rates, Rules and Regulations for Furnishing Natural Gas to become effective November 1, 2006.

The Gas Cost Adjustment (GCA) for firm sales service is $8.7869 per Mcf, $7.9136 per Mcf for high load factor firm sales service, and $7.9136 per Mcf for interruptible sales service. The supporting calculations for the Nineteenth Revised Sheet No. 5 are provided in the following Exhibits:

Exhibit A - Summary of Derivations of Gas Cost Adjustment (GCA) ....

Exhibit B - Expected Gas Cost (EGC) Calculation ....

Exhibit C - Rates used in the Expected Gas Cost (EGC) Calculation .....

Exhibit D - Correction Factor (CF) Calculation ....

Exhibit E - Refund Factor (RF) Calculation..........................

Exhibit F - LVS Pricing Calculation ....

Since the Company's last GCA filing, Case No. 2006-00135, the following changes have occurred in its pipeline and gas supply commodity rates for the GCA period.

1. The commodity rates per MMbtu used are based on historical estimates and/or current data for the quarter November 2006 through January 2007, as shown in Exhibit C, page 19.

2. The Expected Commodity Gas Cost will be approximately $8.0540 MMbtu for the quarter November 2006 through January 2007, as compared to $7.7975 per MMbtu used for the quarter of August 2006 through October 2006.

3. The Company's notice sets out a new Correction Factor of ($0.3088) per Mcf, which will remain in effect until at least January 31, 2007.

The GCA tariff as approved in Case No. 92-558 provides for a Correction Factor (CF) which compensates for the difference between the expected gas cost and the actual gas cost for prior periods. A revision to the GCA tariff effective December 1, 2001, Filing No. T62-1253, provides that the Correction Factor be filed on a quarterly basis. The Company is filing its updated Correction Factor that is based upon the balance in the Company's Account 191 as of July 31, 2006. The calculation for the Correction Factor is shown on Exhibit D, Page 1.

WHEREFORE, Atmos Energy Corporation requests this Commission, pursuant to the Commission's order in Case No. 99-070, to approve the Gas Cost Adjustment (GCA) as filed in Nineteenth Revised Sheet No. 5; and Nineteenth Revised Sheet No. 6 setting out the General Transportation Tariff Rate T-2 for each respective sales rate for meter readings made on and after November 1, 2006.

DATED at Dallas Texas, this 28th Day of September, 2006.

ATMOS ENERGY CORPORATION

By: Thomas J. Morel

Thomas J. Morel
Senior Rate Analyst, Rate Administration
Atmos Energy Corporation

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

GAS COST ADJUSTMENT	)	**CASE NO.**
FILING OF	)	**2006 - 00**438
ATMOS ENERGY CORPORATION	)	

PETITION FOR CONFIDENTIALITY OF INFORMATION BEING FILED WITH THE KENTUCKY PUBLIC SERVICE COMMISSION

Atmos Energy Corporation ("Atmos") respectfully petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001 Section 7 and all other applicable law, for confidential treatment of the information which is described below and which is attached hereto. In support of this Petition, Atmos states as follows:

1. Atmos is filing its Gas Cost Adjustment ("GCA") for the quarterly period commencing on November 1, 2006. This GCA filing also contains Atmos' quarterly Correction Factor (CF) as well as information pertaining to Atmos' projected gas prices. The following two attachments contain information which requires confidential treatment.

   a. The attached Exhibit D contains information from which the actual price being paid by Atmos for natural gas to its supplier can be determined.

   b. The attached Weighted Average Cost of Gas ("WACOG") schedule in support of Exhibit C, page 20 contains confidential information pertaining to prices projected to be paid by Atmos for purchase contracts.

2. Information of the type described above has previously been filed by Atmos with the Commission under petitions for confidentiality. Exhibit D contains information from which it

could be determined what Atmos is paying for natural gas under its gas supply agreement with its existing supplier. The Commission has consistently granted confidential protection to that type of information in each of the prior GCA filings in KPSC Case No. 1999-070. The information contained in the attached WACOG schedule has also been filed with the Commission under a Petition for Confidentiality in Case No. 97-513.

3. All of the information sought to be protected herein as confidential, if publicly disclosed, would have serious adverse consequences to Atmos and its customers. Public disclosure of this information would impose an unfair commercial disadvantage on Atmos. Atmos has successfully negotiated an extremely advantageous gas supply contract that is very beneficial to Atmos and its ratepayers. Detailed information concerning that contract, including commodity costs, demand and transportation charges, reservations fees, etc. on specifically identified pipelines, if made available to Atmos' competitors, (including specifically non-regulated gas marketers), would clearly put Atmos to an unfair commercial disadvantage. Those competitors for gas supply would be able to gain information that is otherwise confidential about Atmos' gas purchases and transportation costs and strategies. The Commission has accordingly granted confidential protection to such information.

4. Likewise, the information contained in the WACOG schedule in support of Exhibit C, page 20, also constitutes sensitive, proprietary information which if publicly disclosed would put Atmos to an unfair commercial disadvantage in future negotiations.

5. Atmos would not, as a matter of company policy, disclose any of the information for which confidential protection is sought herein to any person or entity, except as required by law or pursuant to a court order or subpoena. Atmos' internal practices and policies are directed towards non-disclosure of the attached information. In fact, the information contained in the

attached report is not disclosed to any personnel of Atmos except those who need to know in order to discharge their responsibility. Atmos has never disclosed such information publicly. This information is not customarily disclosed to the public and is generally recognized as confidential and proprietary in the industry.

6. There is no significant interest in public disclosure of the attached information. Any public interest in favor of disclosure of the information is out weighed by the competitive interest in keeping the information confidential.

7. The attached information is also entitled to confidential treatment because it constitutes a trade secret under the two prong test of KRS 265.880: (a) the economic value of the information as derived by not being readily ascertainable by other persons who might obtain economic value by its disclosure; and, (b) the information is the subject of efforts that are reasonable under the circumstances to maintain its secrecy. The economic value of the information is derived by Atmos maintaining the confidentiality of the information since competitors and entities with whom Atmos transacts business could obtain economic value by its disclosure.

8. Pursuant to 807 KAR 5:001 Section 7(3) temporary confidentiality of the attached information should be maintained until the Commission enters an order as to this petition. Once the order regarding confidentiality has been issued, Atmos would have twenty (20) days to seek alternative remedies pursuant to 807 KAR 5:001 Section 7(4).

WHEREFORE, Atmos petitions the Commission to treat as confidential all of the material and information which is included in the attached one volume marked "Confidential".

Respectfully submitted this 28th day of September, 2006.

____

Mark R. Hutchinson
1700 Frederica Street
Suite 201
Owensboro, Kentucky 42301

Douglas Walther
Atmos Energy Corporation
P.O. Box 650250
Dallas, Texas 75265

John N. Hughes
124 W. Todd Street
Frankfort, Kentucky 40601

Attorneys for Atmos Energy Corporation

WHEREFORE, Atmos petitions the Commission to treat as confidential all of the material and information which is included in the attached one volume marked "Confidential".

Respectfully submitted this 28th day of September, 2006.

Mark R. Hutchinson
611 Frederica Street
Owensboro, Kentucky 42301

Douglas Walther
Atmos Energy Corporation
P.O. Box 650250
Dallas, Texas 75265

John N. Hughes
124 W. Todd Street
Frankfort, Kentucky 40601

Attorneys for Atmos Energy Corporation

ATMOS ENERGY CORPORATION

Current Rate Summary

Case No. 2006-00000

Firm Service

Base Charge:

Residential	-	$7.50	per meter per month
Non-Residential	-	20.00	per meter per month
Carriage (T-4)	-	220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

Rate per Mcf[2]			Sales (G-1)		Transport (T-2)		Carriage (T-4)		
First	300[1]	Mcf	@ 9.9769	per Mcf	@ 2.2472	per Mcf	@ 1.1900	per Mcf	(I, N, N)
Next	14,700[1]	Mcf	@ 9.4459	per Mcf	@ 1.7162	per Mcf	@ 0.6590	per Mcf	(I, N, N)
Over	15,000	Mcf	@ 9.2169	per Mcf	@ 1.4872	per Mcf	@ 0.4300	per Mcf	(I, N, N)

High Load Factor Firm Service

HLF demand charge/Mcf	@ 4.5576	@ 4.5576 per Mcf of daily Contract Demand	(N)

Rate per Mcf[2]							
First	300[1]	Mcf	@ 9.1036	per Mcf	@ 1.3739	per Mcf	(I, N)
Next	14,700[1]	Mcf	@ 8.5726	per Mcf	@ 0.8429	per Mcf	(I, N)
Over	15,000	Mcf	@ 8.3436	per Mcf	@ 0.6139	per Mcf	(I, N)

Interruptible Service

Base Charge	-	$220.00	per delivery point per month
Transportation Administration Fee	-	50.00	per customer per meter

Rate per Mcf[2]			Sales (G-2)		Transport (T-2)		Carriage (T-3)		
First	15,000[1]	Mcf	@ 8.4436	per Mcf	@ 0.7139	per Mcf	@ 0.5300	per Mcf	(I, N, N)
Over	15,000	Mcf	@ 8.2727	per Mcf	@ 0.5430	per Mcf	@ 0.3591	per Mcf	(I, N, N)

[1] All gas consumed by the customer (sales, transportation, and carriage; firm, high load factor, and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] DSM, GRI and MLR Riders may also apply, where applicable.

ISSUED: September 28, 2006 Effective: November 1, 2006

(Issued by Authority of an Order of the Public Service Commission in Case No. 2006-00000.)

ISSUED BY: Gary L. Smith Vice President - Marketing & Regulatory Affairs/Kentucky Division

For Entire Service Area
P.S.C. No. 1
Nineteenth SHEET No. 5
Cancelling
Eighteenth SHEET No. 5

ATMOS ENERGY CORPORATION

Current Gas Cost Adjustments

Case No. 2006-00000

Applicable

For all Mcf billed under General Sales Service (G-1) and Interruptible Sales Service (G-2).

Gas Charge = GCA

GCA = EGC + CF + RF + PBRRF

Gas Cost Adjustment Components	G - 1	HLF G - 1	G-2	
EGC (Expected Gas Cost Component)	9.1112	8.2379	8.2379	(I, I, I)
CF (Correction Factor)	(0.3088)	(0.3088)	(0.3088)	(R, R, R)
RF (Refund Adjustment)	(0.0554)	(0.0554)	(0.0554)	(R, R, R)
PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0399	(N, N, N)
GCA (Gas Cost Adjustment)	$8.7869	$7.9136	$7.9136	(I I I)

ISSUED: September 28, 2006 **Effective:** November 1, 2006

(Issued by Authority of an Order of the Public Service Commission in Case No. 2006-00000.)

ISSUED BY: Gary L. Smith Vice President - Marketing & Regulatory Affairs/Kentucky Division

ATMOS ENERGY CORPORATION

Current Transportation and Carriage

Case No. 2006-00000

Case No. 2004-00398

The General Transportation Rate T-2 and Carriage Service (Rates T-3 and T-4) for each respective service net monthly rate is as follows:

System Lost and Unaccounted gas percentage: 1.38%

						Simple Margin		Non-Commodity		Gross Margin		
Transportation Service (T-2)[1]												
a)	Firm Service											
	First	300 [2]	Mcf	@		$1.1900	+	$1.0572	=	$2.2472	per Mcf	(N)
	Next	14,700 [2]	Mcf	@		0.6590	+	1.0572	=	1.7162	per Mcf	(N)
	All over	15,000	Mcf	@		0.4300	+	1.0572	=	1.4872	per Mcf	(N)
b)	High Load Factor Firm Service (HLF)											
	Demand			@		$0.0000	+	4.5576	=	$4.5576	per Mcf of daily contract demand	(N)
	First	300 [2]	Mcf	@		$1.1900	+	$0.1839	=	$1.3739	per Mcf	(N)
	Next	14,700 [2]	Mcf	@		0.6590	+	0.1839	=	0.8429	per Mcf	(N)
	All over	15,000	Mcf	@		0.4300	+	0.1839	=	0.6139	per Mcf	(N)
c)	Interruptible Service											
	First	15,000 [2]	Mcf	@		$0.5300	+	$0.1839	=	$0.7139	per Mcf	(N)
	All over	15,000	Mcf	@		0.3591	+	0.1839	=	0.5430	per Mcf	(N)
Carriage Service[3]												
	Firm Service (T-4)											
	First	300	[2] Mcf	@		$1.1900	+	$0.0000	=	$1.1900	per Mcf	(N)
	Next	14,700	[2] Mcf	@		0.6590	+	0.0000	=	0.6590	per Mcf	(N)
	All over	15,000	[2] Mcf	@		0.4300	+	0.0000	=	0.4300	per Mcf	(N)
	Interruptible Service (T-3)											
	First	15,000 [2]	Mcf	@		$0.5300	+	$0.0000	=	$0.5300	per Mcf	(N)
	All over	15,000	Mcf	@		0.3591	+	0.0000	=	0.3591	per Mcf	(N)

[1] Includes standby sales service under corresponding sales rates. GRI Rider may also apply.

[2] All gas consumed by the customer (Sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[3] Excludes standby sales service.

ISSUED: September 28, 2006 **Effective:** November 1, 2006

(Issued by Authority of an Order of the Public Service Commission in Case No. 2006-00000.)

ISSUED BY: Gary L. Smith Vice President - Marketing & Regulatory Affairs/Kentucky Division

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Sales Service

Line No.	Description	Case No. 2006-00324 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	**G-1**			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 300 Mcf	1.1900	1.1900	0.0000
5	Next 14,700 Mcf	0.6590	0.6590	0.0000
6	Over 15,000 Mcf	0.4300	0.4300	0.0000
7				
8	Gas Cost Adjustment Components			
9	EGC (Expected Gas Cost):			
10	Commodity	7.7975	8.0540	0.2565
11	Demand	1.0572	1.0572	0.0000
12	Take-Or-Pay	0.0000	0.0000	0.0000
13	Transition Costs	0.0000	0.0000	0.0000
14	Total EGC	8.8547	9.1112	0.2565
15	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
16	CF (Correction Factor)	(0.1749)	(0.3088)	(0.1339)
17	RF (Refund Adjustment)	(0.0017)	(0.0554)	(0.0537)
18	PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0000
19	GCA (Gas Cost Adjustment)	8.7180	8.7869	0.0689
20	Total Billing Cost of Gas	8.7180	8.7869	0.0689
21				
22	Commodity Charge (GCA included):			
23	First 300 Mcf	9.9080	9.9769	0.0689
24	Next 14,700 Mcf	9.3770	9.4459	0.0689
25	Over 15,000 Mcf	9.1480	9.2169	0.0689
26				
27	**HLF (High Load Factor)**			
28				
29	Commodity Charge (Base Rate per Case No. 99-070):			
30	First 300 Mcf	1.1900	1.1900	0.0000
31	Next 14,700 Mcf	0.6590	0.6590	0.0000
32	Over 15,000 Mcf	0.4300	0.4300	0.0000
33				
34	Gas Cost Adjustment Components			
35	EGC (Expected Gas Cost):			
36	Commodity	7.7975	8.0540	0.2565
37	Demand	0.1839	0.1839	0.0000
38	Take-Or-Pay	0.0000	0.0000	0.0000
39	Transition Costs	0.0000	0.0000	0.0000
40	Total EGC	7.9814	8.2379	0.2565
41	Less: BCOG (Base Cost of Gas)	0.0000	0.0000	0.0000
42	CF (Correction Factor)	(0.1749)	(0.3088)	(0.1339)
43	RF (Refund Adjustment)	(0.0017)	(0.0554)	(0.0537)
44	PBRRF (Performance Based Rate Recovery Factor)	0.0399	0.0399	0.0000
45	GCA (Gas Cost Adjustment)	7.8447	7.9136	0.0689
46	Total Cost of Gas to Bill (excludes MDQ Demand)	7.8447	7.9136	0.0689
47				
48	Commodity Charge (GCA included):			
49	First 300 Mcf	9.0347	9.1036	0.0689
50	Next 14,700 Mcf	8.5037	8.5726	0.0689
51	Over 15,000 Mcf	8.2747	8.3436	0.0689
52				
53	HLF Demand			
54	Contract Demand Factor	4.5576	4.5576	0.0000

Atmos Energy Corporation
Comparison of Current and Previous Cases
Interruptible Sales Service

Line No.	Description	Case No. 2006-00324	Case No. 2006-00000	Difference
		$/Mcf	$/Mcf	$/Mcf
1	G-2			
2				
3	Commodity Charge (Base Rate per Case No. 99-070):			
4	First 15,000 Mcf	0.5300	0.5300	0.0000
5	Over 15,000 Mcf	0.3591	0.3591	0.0000
6				
7	Gas Cost Adjustment Components			
8	Expected Gas Cost (EGC):			
9	Commodity	7.7975	8.0540	0.2565
10	Demand	0.1839	0.1839	0.0000
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0000	0.0000	0.0000
13	Total EGC	7.9814	8.2379	0.2565
14	Less: Base Cost of Gas (BCOG)	0.0000	0.0000	0.0000
15	Correction Factor (CF)	(0.1749)	(0.3088)	(0.1339)
16	Refund Adjustment (RF)	(0.0017)	(0.0554)	(0.0537)
17	Performance Based Rate Recovery Factor (PBRRF)	0.0399	0.0399	0.0000
18	Gas Cost Adjustment (GCA)	7.8447	7.9136	0.0689
19	Total Cost of Gas to Bill	7.8447	7.9136	0.0689
20				
21	Commodity Charge (GCA included):			
22	First 15,000 Mcf	8.3747	8.4436	0.0689
23	Over 15,000 Mcf	8.2038	8.2727	0.0689
24				
25				

Line No.		Case No.	Effective Date	G - 1	G - 1 / HLF	G - 2
26	Monthly Refund Factor					
29	1 -	1999-070 L	07/01/01	0.0000	0.0000	0.0000
30	2 -	1999-070 M	08/01/01	0.0000	0.0000	0.0000
31	3 -	1999-070 N	10/01/01	0.0000	0.0000	0.0000
32	4 -	1999-070 O	11/01/01	(0.0019)	(0.0019)	(0.0019)
33	5 -	1999-070 P	05/03/02	0.0000	0.0000	0.0000
34	6 -	2002-00251	08/01/02	(0.0095)	(0.0095)	(0.0019)
35	7 -	2002-00359	11/01/02	(0.1574)	(0.1574)	(0.0391)
36	8 -	2003-00377	11/01/03	(0.0006)	(0.0006)	(0.0006)
37	9 -	2004-00269	08/01/04	(0.0048)	(0.0048)	(0.0048)
38	10 -	2005-00399	11/01/05	(0.0017)	(0.0017)	(0.0017)
39	11 -	2006-00000	11/01/06	(0.0554)	(0.0554)	(0.0554)
40	12 -					
41						
42	Total Supplier Refund Adjustment (RF)			(0.0554)	(0.0554)	(0.0554)
43						

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description	Case No. 2006-00324 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	T-2 \ G-1			
2				
3				
4	Simple Margin (Base Rate per Case No. 99-070):			
5	First 300 Mcf	1.1900	1.1900	0.0000
6	Next 14,700 Mcf	0.6590	0.6590	0.0000
7	Over 15,000 Mcf	0.4300	0.4300	0.0000
8				
9	Non-Commodity Components:			
10	Demand	1.0572	1.0572	0.0000
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0000	0.0000	0.0000
13	RF (Refund Adjustment)	0.0000	0.0000	0.0000
14	Total	1.0572	1.0572	0.0000
15				
16	Gross Margin:			
17	First 300 Mcf	2.2472	2.2472	0.0000
18	Next 14,700 Mcf	1.7162	1.7162	0.0000
19	Over 15,000 Mcf	1.4872	1.4872	0.0000
20				
21	T-2\G-1\HLF			
22				
23	Simple Margin (Base Rate per Case No. 99-070):			
24	First 300 Mcf	1.1900	1.1900	0.0000
25	Next 14,700 Mcf	0.6590	0.6590	0.0000
26	Over 15,000 Mcf	0.4300	0.4300	0.0000
27				
28	Non-Commodity Components:			
29	Demand	0.1839	0.1839	0.0000
30	Take-Or-Pay	0.0000	0.0000	0.0000
31	Transition Costs	0.0000	0.0000	0.0000
32	RF (Refund Adjustment)	0.0000	0.0000	0.0000
33	Total	0.1839	0.1839	0.0000
34				
35	Gross Margin (Excluding HLF Demand):			
36	First 300 Mcf	1.3739	1.3739	0.0000
37	Next 14,700 Mcf	0.8429	0.8429	0.0000
38	Over 15,000 Mcf	0.6139	0.6139	0.0000
39				
40	HLF Demand			
41	Contract Demand Factor	4.5576	4.5576	0.0000
42				

Atmos Energy Corporation
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description			Case No. 2006-00324	Case No. 2006-00000	Difference
				$/Mcf	$/Mcf	$/Mcf
1	**Carriage Service**					
2						
3	Firm Service (T-4)					
4	Simple Margin (Base Rate per Case No. 99-070):					
5	First	300	Mcf	1.1900	1.1900	0.0000
6	Next	14,700	Mcf	0.6590	0.6590	0.0000
7	Over	15,000	Mcf	0.4300	0.4300	0.0000
8						
9	Non-Commodity Components:					
11	Take-Or-Pay			0.0000	0.0000	0.0000
13	RF (Refund Adjustment)			0.0000	0.0000	0.0000
14	Total			0.0000	0.0000	0.0000
15						
16	Gross Margin:					
17	First	300	Mcf	1.1900	1.1900	0.0000
18	Next	14,700	Mcf	0.6590	0.6590	0.0000
19	Over	15,000	Mcf	0.4300	0.4300	0.0000
20						

Comparison of Current and Previous Cases
Interruptible Transportation and Carriage Service

Line No.	Description			Case No. 2006-00324 $/Mcf	Case No. 2006-00000 $/Mcf	Difference $/Mcf
1	**General Transporation (T-2)**					
2						
3	Interruptible Service (G-2)					
4	Simple Margin (Base Rate per Case No. 99-070):					
5	First	15,000	Mcf	0.5300	0.5300	0.0000
6	Over	15,000	Mcf	0.3591	0.3591	0.0000
7						
8	Non-Commodity Components:					
9	Demand			0.1839	0.1839	0.0000
10	Take-Or-Pay			0.0000	0.0000	0.0000
11	Transition Costs			0.0000	0.0000	0.0000
12	RF (Refund Adjustment)			0.0000	0.0000	0.0000
13	Total			0.1839	0.1839	0.0000
14						
15	Gross Margin:					
16	First	15,000	Mcf	0.7139	0.7139	0.0000
17	Over	15,000	Mcf	0.5430	0.5430	0.0000
18						
19	**Carriage Service**					
20						
21	Carriage Service (T-3)					
22	Simple Margin (Base Rate per Case No. 99-070):					
23	First	15,000	Mcf	0.5300	0.5300	0.0000
24	Over	15,000	Mcf	0.3591	0.3591	0.0000
25						
26	Non-Commodity Components:					
28	Take-Or-Pay			0.0000	0.0000	0.0000
30	RF (Refund Adjustment)			0.0000	0.0000	0.0000
31	Total			0.0000	0.0000	0.0000
32						
33	Gross Margin:					
34	First	15,000	Mcf	0.5300	0.5300	0.0000
35	Over	15,000	Mcf	0.3591	0.3591	0.0000
36						

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Texas Gas

				(1)	(2)	(3)	(4)	(5)
							Non-Commodity	
Line No.	**Description**		**Tariff Sheet No.**	**Annual Units**	**Rate**	**Total**	**Demand**	**Transition Costs**
				MMbtu	$/MMbtu	$	$	$
1	**SL to Zone 2**							
2	NNS Contract #	N0210		12,617,673				
3	Base Rate		20		0.3088	3,896,336	3,896,336	
4	GSR		20		0.0000	0		0
5	TCA Adjustment		20		0.0000	0	0	
6	Unrec TCA Surch		20		0.0000	0	0	
7	ISS Credit		20		0.0000	0	0	
8	Misc Rev Cr Adj		20		0.0000	0	0	
9	GRI		20		0.0000	0	0	
6								
7	Total SL to Zone 2			12,617,673		3,896,336	3,896,336	0
8								
9	**SL to Zone 3**							
10	NNS Contract #	N0340		27,480,375				
11	Base Rate		20		0.3543	9,736,297	9,736,297	
12	GSR		20		0.0000	0		0
13	TCA Adjustment		20		0.0000	0	0	
14	Unrec TCA Surch		20		0.0000	0	0	
15	ISS Credit		20		0.0000	0	0	
16	Misc Rev Cr Adj		20		0.0000	0	0	
17	GRI		20		0.0000	0	0	
18								
19	FT Contract #	3355		3,130,605				
20	Base Rate		24		0.2494	780,773	780,773	
21	GSR		24		0.0000	0		0
22	TCA Adjustment		24		0.0000	0	0	
23	Unrec TCA Surch		24		0.0000	0	0	
24	ISS Credit		24		0.0000	0	0	
25	Misc Rev Cr Adj		24		0.0000	0	0	
26	GRI		24		0.0000	0	0	
27								
28								
29	Total SL to Zone 3			30,610,980		10,517,070	10,517,070	0
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Texas Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**Zone 1 to Zone 3**							
2	FT Contract #	3355		2,344,395				
3	Base Rate		24		0.2194	514,360	514,360	
4	GSR		24		0.0000	0		0
5	TCA Adjustment		24		0.0000	0	0	
6	Unrec TCA Surch		24		0.0000	0	0	
7	ISS Credit		24		0.0000	0	0	
8	Misc Rev Cr Adj		24		0.0000	0	0	
9	GRI		24		0.0000	0	0	
6								
7	Total Zone 1 to Zone 3			2,344,395		514,360	514,360	0
8								
9	**SL to Zone 4**							
10	NNS Contract #	N0410		3,320,769				
11	Base Rate		20		0.4190	1,391,402	1,391,402	
12	GSR		20		0.0000	0		0
13	TCA Adjustment		20		0.0000	0	0	
14	Unrec TCA Surch		20		0.0000	0	0	
15	ISS Credit		20		0.0000	0	0	
16	Misc Rev Cr Adj		20		0.0000	0	0	
17	GRI		20		0.0000	0	0	
18								
19	FT Contract #	3819		1,277,500				
20	Base Rate		24		0.3142	401,391	401,391	
21	GSR		24		0.0000	0		0
22	TCA Adjustment		24		0.0000	0	0	
23	Unrec TCA Surch		24		0.0000	0	0	
24	ISS Credit		24		0.0000	0	0	
25	Misc Rev Cr Adj		24		0.0000	0	0	
26	GRI		24		0.0000	0	0	
27								
28	Total SL to Zone 4			4,598,269		1,792,793	1,792,793	0
29								
30	Total SL to Zone 2			12,617,673		3,896,336	3,896,336	0
31	Total SL to Zone 3			30,610,980		10,517,070	10,517,070	0
32	Total Zone 1 to Zone 3			2,344,395		514,360	514,360	0
33								
34	Total Texas Gas			50,171,317		16,720,559	16,720,559	0
35								
36								
37	Vendor Reservation Fees (Fixed)					0	0	
38								
39	TOP & Direct Billed Transition costs					0		
40								
41	Total Texas Gas Area Non-Commodity					16,720,559	16,720,559	0
42								
43								

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Tennessee Gas

Line No.	Description	Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Non-Commodity Transition Costs
			MMbtu	$/MMbtu	$	$	$
1	***0 to Zone 2***						
2	FT-G Contract # 2546.1		12,844	9.0600			
3	Base Rate	23B		9.0600	116,367	116,367	
4	Settlement Surcharge	23B		0.0000	0		0
5	PCB Adjustment	23B		0.0000	0		0
6							
7	FT-G Contract # 2548.1		4,363	9.0600			
8	Base Rate	23B		9.0600	39,529	39,529	
9	Settlement Surcharge	23B		0.0000	0		0
10	PCB Adjustment	23B		0.0000	0		0
11							
12	FT-G Contract # 2550.1		5,739	9.0600			
13	Base Rate	23B		9.0600	51,995	51,995	
14	Settlement Surcharge	23B		0.0000	0		0
15	PCB Adjustment	23B		0.0000	0		0
16							
17	FT-G Contract # 2551.1		4,447	9.0600			
18	Base Rate	23B		9.0600	40,290	40,290	
19	Settlement Surcharge	23B		0.0000	0		0
20	PCB Adjustment	23B		0.0000	0		0
21							
22							
23	Total Zone 0 to 2		27,393		248,181	248,181	0
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							

Atmos Energy Corporation
Expected Gas Cost - Non Commodity
Tennessee Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	**1 to Zone 2**							
2	FT-G Contract #	2546		114,156	7.6200			
3	Base Rate		23B		7.6200	869,869	869,869	
4	Settlement Surcharge		23B		0.0000	0		0
5	PCB Adjustment		23B		0.0000	0		0
6								
7	FT-G Contract #	2548		44,997	7.6200			
8	Base Rate		23B		7.6200	342,877	342,877	
9	Settlement Surcharge		23B		0.0000	0		0
10	PCB Adjustment		23B		0.0000	0		0
11								
12	FT-G Contract #	2550		59,741	7.6200			
13	Base Rate		23B		7.6200	455,226	455,226	
14	Settlement Surcharge		23B		0.0000	0		0
15	PCB Adjustment		23B		0.0000	0		0
16								
17	FT-G Contract #	2551		45,058	7.6200			
18	Base Rate		23B		7.6200	343,342	343,342	
19	Settlement Surcharge		23B		0.0000	0		0
20	PCB Adjustment		23B		0.0000	0		0
21								
22	Total Zone 1 to 2			263,952		2,011,314	2,011,314	0
23								
24	Total Zone 0 to 2			27,393		248,181	248,181	0
25								
26	Total Zone 1 to 2 and Zone 0 to 2			291,345		2,259,495	2,259,495	0
27								
28	**Gas Storage**							
29	Production Area:							
30	Demand		27	34,968	2.0200	70,635	70,635	
31	Space Charge		27	4,916,148	0.0248	121,920	121,920	
32	Market Area:							
33	Demand		27	237,408	1.1500	273,019	273,019	
34	Space Charge		27	10,846,308	0.0185	200,657	200,657	
35	Total Storage					666,231	666,231	
36								
37	Vendor Reservation Fees (Fixed)					0	0	
38								
39	TOP & Direct Billed Transition costs					0	0	0
40								
41	Total Tennessee Gas Area FT-G Non-Commodity					2,925,726	2,925,726	0
42								
43								
44								
45								
46								
47								
48								
49								
50								
51								

Atmos Energy Corporation
Expected Gas Cost - Commodity
Purchases in Texas Gas Service Area

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1							
2							
3							
4							
5							
6							
7	Firm Transportation				1,760,200		
8	Indexed Gas Cost					8.7170	15,343,663
9	Base (Weighted on MDQs)	25				0.0439	77,273
10	TCA Adjustment	25				0.0000	0
11	Unrecovered TCA Surcharge	25				0.0000	0
12	Cash-out Adjustment	25				0.0000	0
13	GRI	25				0.0000	0
14	ACA	25				0.0018	3,168
15	Fuel and Loss Retention @	36	2.10%			0.1870	329,157
16						8.9497	15,753,261
17	No Notice Storage						
18	Net (Injections)/Withdrawals				2,300,000		
19	Indexed Gas Cost					7.7010	17,712,300
20	Commodity (Zone 3)	20				0.0508	116,840
21	Fuel and Loss Retention @	36	2.05%			0.1612	370,760
22						7.9130	18,199,900
23							
24							
25	Total Purchases in Texas Area				4,060,200	8.3624	33,953,161
26							
27							

28 Used to allocate transportation non-commodity

Line No.	Description	Annualized MDQs in MMbtu	Allocation	Commodity Charge $/MMbtu	Weighted Average
29					
30					
31					
32	Texas Gas				
33	SL to Zone 2	12,617,673	25.15%	$0.0399	$ 0.0100
34	SL to Zone 3	30,610,980	61.01%	0.0445	0.0271
35	1 to Zone 3	2,344,395	4.67%	0.0422	0.0020
36	SL to Zone 4	4,598,269	9.17%	0.0528	0.0048
37	Total	50,171,317	100.00%		$ 0.0439
38					
39	Tennessee Gas				
40	0 to Zone 2	27,393	9.40%	0.0880	$ 0.0083
41	1 to Zone 2	263,952	90.60%	0.0776	0.0703
42	Total	291,345	100.00%		$ 0.0786
43					

Atmos Energy Corporation
Expected Gas Cost - Commodity
Purchases in Tennessee Gas Service Area

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	FT-A and FT-G				684,900		
2	Indexed Gas Cost					8.7170	5,970,273
3	Base Commodity (Weighted on MDQs)					0.0786	53,833
4	GRI	23C				0 0000	0
5	ACA	23C				0 0018	1,233
6	Transition Cost	23C				0.0000	0
7	Fuel and Loss Retention	29	4.28%			0.3898	266,974
8						9.1872	6,292,313
9							
10							
11	FT-GS				101,900		
12	Indexed Gas Cost					8.7170	888,262
13	Base Rate	20				0.5844	59,550
14	GRI	20				0.0000	0
15	ACA	20				0.0018	183
16	PCB Adjustment	20				0.0000	0
17	Settlement Surcharge	20				0.0000	0
18	Fuel and Loss Retention	29	4.28%			0.3898	39,721
19						9.6930	987,716
20							
21							
22	Gas Storage						
23	FT-A & FT-G Market Area (Injections)/Withdrawals				810,000		
24	Indexed Gas Cost/Storage					6.5400	5,297,400
25	Injection Rate	27				0.0102	8,262
26	Fuel and Loss Retention	27	1 49%			0.0989	80,109
27	Total					6.6491	5,385,771
28							
29							
30							
31							
32							
33							
34							
35							
36							
37	Total Tennessee Gas Zones				1,596,800	7.9320	12,665,800
38							
39							

Atmos Energy Corporation
Expected Gas Cost
Trunkline Gas

Commodity

				(1)	(2)	(3)	(4)
Line No.	**Description**	**Tariff Sheet No.**		**Purchases**		**Rate**	**Total**
				Mcf	MMbtu	$/MMbtu	$
1	Firm Transportation						
2	Expected Volumes				400,000		
3	Indexed Gas Cost					8.7170	3,486,800
4	Base Commodity					0.0213	8,520
5	GRI	10				-	0
6	ACA	10				0.0019	760
7	Fuel and Loss Retention	10	1.11%			0.0978	39,120
8						8.8380	3,535,200
9							
10							

Non-Commodity

		(1)	(2)	(3)	(4)	(5)	(6)
					Non-Commodity		
Line No.	**Description**	**Tariff Sheet No.**	**Annual Units**	**Rate**	**Total**	**Demand**	**Transition Costs**
			MMbtu	$/MMbtu	$	$	$
11	FT-G Contract # 014573		87,475				
12	Discount Rate on MDQs			7.2000	629,820	629,820	
13							
14			92,125				
15	GRI Surcharge	10			0	-	
16							
17	Reservation Fee				-	-	
18							
19	Total Trunkline Area Non-Commodity				629,820	629,820	
20							
21							

Atmos Energy Corporation
Demand Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Total Demand Cost:						
2	Texas Gas	$16,720,559					
3	Midwestern	0					
4	Tennessee Gas	2,925,726					
5	Trunkline	629,820					
6	Total	$20,276,105					
7							
8			Allocated	Related	Monthly Demand Charge		
9	Demand Cost Allocation:	Factors	Demand	Volumes	Firm	Interruptible	HLF
10	All	0.1850	$3,751,079	20,401,274	0.1839	0.1839	0.1839
11	Firm	0.8150	16,525,026	18,923,274	0.8733	NA	NA
12	Total	1.0000	$20,276,105		1.0572	0.1839	0.1839
13							
14			Volumetric Basis for				
15		Annualized	Monthly Demand Charge				
16		Mcf @14.65	All	Firm			
17	Firm Service						
18	Sales:						
19	G-1	18,887,274	18,887,274	18,887,274	1.0572		
20	HLF	60,000	60,000		0.1839 + HLF MDQ Demand		
21	LVS-1	0	0	0	1.0572		
22	Total Firm Sales	18,947,274	18,947,274	18,887,274			
23							
24	Transportation:						
25	T-2 \ G-1	36,000	36,000	36,000	1.0572		
26	HLF	0	0		0.1839		
27	Total Firm Service	18,983,274	18,983,274	18,923,274			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	684,000	684,000		1.0572	0.1839	
32	LVS-2	154,000	154,000		1.0572	0.1839	
33	Total Sales	838,000	838,000				
34							
35	Transportation:						
36	T-2 \ G-2	580,000	580,000		1.0572	0.1839	
37							
38	Total Interruptible Service	1,418,000	1,418,000				
39							
40	Carriage Service						
41	T-3 & T-4	23,438,000					
42							
43	Total	43,839,274	20,401,274	18,923,274			
44							
45	HLF MDQ Demand						
46	Firm Demand Cost		$16,525,026				
47	Peak Day Thru-put		302,152	Mcf/Peak Day			
48	Times:		12	Months/Year			
49	Total Annualized Peak Day Demand		3,625,824				
50	Demand Charge per MDQ		$4.5576	/ MDQ of Customer's Contract			
51							
52							
53	Note: LVS Credit =	($28,321)					

Atmos Energy Corporation
Take-or-Pay and Transition Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Other Fixed Charges	Take-or-Pay	Transition				
2	Texas Gas		$0				
3	Tennessee Gas		0				
4	Total	$0	$0				
5							
6							
7			Related	Charge			
8	Other Fixed Charges	Amount	Volumes	$/Mcf			
9	Take-or-Pay	0	43,839,274	0.0000			
10	Transition	0	20,401,274	0.0000			
11	Total	$0		0.0000			
12							
13							
14			Volumetric Basis for				
15		Annual	Other Fixed Charges			Other Fixed Charges	
16		Expected Mcf	Take-or-Pay	Transition		Take-or-Pay	Transition
17	Firm Service						
18	Sales:						
19	G-1	18,887,274	18,887,274	18,887,274			0.0000
20	HLF	60,000	60,000	60,000			0.0000
21	LVS-1	0	0	0			0.0000
22	Total Firm Sales	18,947,274	18,947,274	18,947,274			
23							
24	Transportation:						
25	T-2 \ G-1	36,000	36,000	36,000			0.0000
26	T-2 \ G-1 \ HLF	0					0.0000
27	Total Firm Service	18,983,274	18,983,274	18,983,274			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	684,000	684,000	684,000			0.0000
32	LVS-2	154,000	154,000	154,000			0.0000
33	Total Sales	838,000	838,000	838,000			
34							
35	Transportation:						
36	T-2 \ G-2	580,000	580,000	580,000			0.0000
37							
38	Total Interruptible Service	1,418,000	1,418,000	1,418,000			
39							
40	Carriage Service						
41	T-3 & T-4	23,438,000	23,438,000	NA			
42							
43	Total	43,839,274	43,839,274	20,401,274			
44							
45							
46	Note: LVS Credit =	$0					
47							

Atmos Energy Corporation
Expected Gas Cost - Commodity
Total System

Line No.	Description		(1) Purchases	(2)	(3) Rate	(4) Total
			Mcf	MMbtu	$/MMbtu	$
1	**Texas Gas Area**					
2	No Notice Service		0	0	0.0000	0
3	Firm Transportation		1,717,268	1,760,200	8.9497	15,753,261
4	No Notice Storage		2,243,902	2,300,000	7.9130	18,199,900
5	Total Texas Gas Area		3,961,170	4,060,200	8.3624	33,953,161
6						
7	**Tennessee Gas Area**					
8	FT-A and FT-G		658,558	684,900	9.1872	6,292,313
9	FT-GS		97,981	101,900	9.6930	987,716
10	Gas Storage					
11	FT-A and FT-G Injections		778,846	810,000	6.6491	5,385,771
12	FT-GS Withdrawals		0	0	0.0000	0
13			1,535,385	1,596,800	7.9320	12,665,800
14	**Trunkline Gas Area**					
15	Firm Transportation		386,473	400,000	8.8380	3,535,200
16						
17						
18	**WKG System Storage**					
19	Injections		0	0		0
20	Withdrawals		3,680,000	3,772,000	6.8300	25,762,760
21	Net WKG Storage		3,680,000	3,772,000	6.8300	25,762,760
22						
23						
24	Local Production		59,512	61,000	8.9497	545,932
25						
26						
27						
28	Total Commodity Purchases		9,622,540	9,890,000	7.7313	76,462,853
29						
30	Lost & Unaccounted for @	1.38%	132,791	136,482		
31						
32	Total Deliveries		9,489,749	9,753,518	7.8395	76,462,853
33						
34	LVS Commodity Credit to System					
35	LVS Sales		(20,000)	(20,556)	9.4164	(193,564)
36						
37						
38	Total Expected Commodity Cost		9,469,749	9,732,962	7.8362	76,269,289
39						
40	Expected Commodity Cost ($/Mcf)				8.0540	
41						
42						
43						

Atmos Energy Corporation
Load Factor Calculation for Demand Allocation

Line No.	Description	MCF	
	Annualized Volumes Subject to Demand Charges		
1	Sales Volume	19,631,274	
2	Large Volume Sales (Annualized)	154,000	
3	Transportation	616,000	
4	Total Mcf Billed Demand Charges	20,401,274	
5	Divided by: Days/Year	365	
7	Average Daily Sales and Transport Volumes	55,894	
8			
10	Peak Day Sales and Transportation Volume		
11	Estimated total company firm requirements for 5 degree average		
12	temperature day from Peak Day Book - with adjustments per rate filing	302,152	Mcf/Peak Day
13			
14			
15	New Load Factor (line 7 / line 12)	0.1850	

Texas Gas Transmission LLP

Substitute Seventh Revised Sheet No. 20 : Effective

Superseding: Second Sub Sixth Rev Sheet No. 20

Currently Effective Maximum Transportation Rates ($ per MMBtu)
For Service Under Rate Schedule NNS

	Base Tariff Rates (1)	FERC ACA (2)	Currently Effective Rates (3)
Zone SL			
Daily Demand	0.1800		0.1800
Commodity	0.0253	0.0018	0.0271
Overrun	0.2053	0.0018	0.2071
Zone 1			
Daily Demand	0.2782		0.2782
Commodity	0.0431	0.0018	0.0449
Overrun	0.3213	0.0018	0.3231
Zone 2			
Daily Demand	0.3088		0.3088
Commodity	0.0460	0.0018	0.0478
Overrun	0.3548	0.0018	0.3566
Zone 3			
Daily Demand	0.3543		0.3543
Commodity	0.0490	0.0018	0.0508
Overrun	0.4033	0.0018	0.4051
Zone 4			
Daily Demand	0.4190		0.4190
Commodity	0.0614	0.0018	0.0632
Overrun	0.4804	0.0018	0.4822

Minimum Rate: Demand $-0-; Commodity - Zone SL 0.0163
Zone 1 0.0186
Zone 2 0.0223
Zone 3 0.0262
Zone 4 0.0308

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental transportation charge of:

Daily Demand	$0.0621
Commodity	$0.0155
Overrun	$0.0776

This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Substitute Fifth Revised Sheet No. 24 : Effective

Superseding: Second Sub Fourth Rev Sheet No. 24

Currently Effective Maximum Daily Demand Rates ($ per MMBtu)
For Service Under Rate Schedule FT

	Currently Effective Rates [1]
SL-SL	0.0794
SL-1	0.1552
SL-2	0.2120
SL-3	0.2494
SL-4	0.3142
1-1	0.1252
1-2	0.1820
1-3	0.2194
1-4	0.2842
2-2	0.1332
2-3	0.1705
2-4	0.2334
3-3	0.1181
3-4	0.1810
4-4	0.1374

Minimum Rates: Demand $-0-

Backhaul rates equal fronthaul rates to zone of delivery.

[1] Currently Effective Rates are equal to the Base Tariff Rates.

Note: The maximum reservation charge component of the maximum firm volumetric capacity release rate shall be the applicable maximum daily demand rate herein pursuant to Section 25 of the General Terms and Conditions.

For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental Daily Demand charge of $0.0621. This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Substitute Sixth Revised Sheet No. 25 : Effective

Superseding: Second Sub Fifth Rev Sheet No. 25

Currently Effective Maximum Commodity Rates ($ per MMBtu)
For Service Under Rate Schedule FT

	Base Tariff Rates (1)	FERC ACA (2)	Currently Effective Rates (3)
SL-SL	0.0104	0.0018	0.0122
SL-1	0.0355	0.0018	0.0373
SL-2	0.0399	0.0018	0.0417
SL-3	0.0445	0.0018	0.0463
SL-4	0.0528	0.0018	0.0546
1-1	0.0337	0.0018	0.0355
1-2	0.0385	0.0018	0.0403
1-3	0.0422	0.0018	0.0440
1-4	0.0508	0.0018	0.0526
2-2	0.0323	0.0018	0.0341
2-3	0.0360	0.0018	0.0378
2-4	0.0446	0.0018	0.0464
3-3	0.0312	0.0018	0.0330
3-4	0.0398	0.0018	0.0416
4-4	0.0360	0.0018	0.0378

Minimum Rates: Commodity minimum base rates are presented on Sheet 31.

Backhaul rates equal fronthaul rates to zone of delivery.

Note: For receipts from Enterprise Texas Pipeline, L.P./Texas Eastern Transmission, LP interconnect near Beckville, Texas, the above rates shall be increased to include an incremental Commodity charge of $0.0155. This receipt point is available to those customers agreeing to pay the incremental rate(s) applicable to such point and is not available for pooling under Rate Schedule TAPS.

Sub 1 Rev 3 Rev Sheet No. 36 : Effective

Superseding: Third Revised Sheet No. 36

Schedule of Currently Effective Fuel Retention Percentages
Pursuant to Section 16 of the General Terms and Conditions

NNS/SGT/SNS RATE SCHEDULES

NNS/SGT WINTER

Delivery Zone	PFRP{1}	FAP{2}	EFRP{3}
SL	0.58%	0.59%	1.17%
1	2.53%	(0.76%)	1.77%
2	2.62%	(0.55%)	2.07%
3	2.81%	(0.76%)	2.05%
4	4.39%	(0.78%)	3.61%

NNS/SGT/SNS SUMMER

Delivery Zone	PFRP{1}	FAP{2}	EFRP{3}
SL	0.23%	(0.23%)	0.00%
1	2.26%	(0.19%)	2.07%
2	2.48%	0.23%	2.71%
3	2.71%	(0.15%)	2.56%
4	3.01%	0.22%	3.23%

FT/STF/IT RATE SCHEDULES

WINTER

Rec/Del Zone	PFRP	FAP	EFRP
SL/SL	0.25%	1.12%	1.37%
SL or 1/1	1.44%	(0.88%)	0.56%
SL or 1/2	1.83%	(0.77%)	1.06%
SL or 1/3	2.05%	0.05%	2.10%
SL or 1/4	2.71%	(0.27%)	2.44%
2/2	0.11%	0.41%	0.52%
2/3	0.22%	0.82%	1.04%
2/4	0.88%	0.50%	1.38%
3/3	0.11%	0.41%	0.52%
3/4	0.66%	0.00%	0.66%
4/4	0.33%	0.00%	0.33%

SUMMER

Rec/Del Zone	PFRP	FAP	EFRP
SL/SL	0.24%	1.22%	1.46%
SL or 1/1	1.45%	(0.69%)	0.76%
SL or 1/2	2.15%	(0.53%)	1.62%
SL or 1/3	2.20%	0.10%	2.30%
SL or 1/4	3.05%	0.03%	3.08%
2/2	0.03%	0.31%	0.34%
2/3	0.05%	0.63%	0.68%
2/4	0.90%	0.56%	1.46%
3/3	0.03%	0.31%	0.34%
3/4	0.85%	0.00%	0.85%
4/4	0.43%	0.00%	0.43%

FSS/ISS RATE SCHEDULES

Withdrawal

PFRP	FAP	EFRP
0.89%	(0.01%)	0.88%

Injection

PFRP	FAP	EFRP
0.63%	0.24%	0.87%

{1} Projected Fuel Retention Percentage

(2) Fuel Adjustment Percentage
(3) Effective Fuel Retention Percentage

Thirty-Third Revised Sheet No. 20 : Effective

Superseding: Thirty-Second Revised Sheet No. 20

RATES PER DEKATHERM

FIRM TRANSPORTATION - GS RATES (FT-GS)

Base Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.2138		$0.4203	$0.5844	$0.6748	$0.7814	$0.8952	$1.0698
L		$0.1771						
1	$0.4318		$0.3268	$0.4951	$0.5849	$0.6915	$0.8052	$0.9804
2	$0.5844		$0.4951	$0.2000	$0.2897	$0.4144	$0.5106	$0.6852
3	$0.6748		$0.5849	$0.2897	$0.1489	$0.3995	$0.4951	$0.6698
4	$0.7995		$0.7096	$0.4144	$0.3995	$0.1886	$0.2311	$0.4061
5	$0.8952		$0.8052	$0.5106	$0.4951	$0.2311	$0.1989	$0.3466
6	$1.0698		$0.9804	$0.6852	$0.6698	$0.4061	$0.3466	$0.2374

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
L		$0.0000						
1	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
3	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
4	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
5	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
6	$0.0000		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Annual Charge Adjustment (ACA): $0.0018

Maximum Rates 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.2156		$0.4221	$0.5862	$0.6766	$0.7832	$0.8970	$1.0716
L		$0.1789						
1	$0.4336		$0.3286	$0.4969	$0.5867	$0.6933	$0.8070	$0.9822
2	$0.5862		$0.4969	$0.2018	$0.2915	$0.4162	$0.5124	$0.6870
3	$0.6766		$0.5867	$0.2915	$0.1507	$0.4013	$0.4969	$0.6716
4	$0.8013		$0.7114	$0.4162	$0.4013	$0.1904	$0.2329	$0.4079
5	$0.8970		$0.8070	$0.5124	$0.4969	$0.2329	$0.2007	$0.3484
6	$1.0716		$0.9822	$0.6870	$0.6716	$0.4079	$0.3484	$0.2392

Minimum Rates

DELIVERY ZONE

Tennessee Gas Pipeline

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Notes:

1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2008 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

3/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Seventeenth Revised Sheet No. 23A : Effective

Superseding: Sixteenth Revised Sheet No. 23A

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0457		$0.0687	$0.0898	$0.0996	$0.1136	$0.1249	$0.1626
L		$0.0304						
1	$0.0687		$0.0590	$0.0794	$0.0892	$0.1032	$0.1144	$0.1521
2	$0.0898		$0.0794	$0.0451	$0.0548	$0.0699	$0.0801	$0.1177

3	$0.0996	$0.0892	$0.0548	$0.0384	$0.0681	$0.0783	$0.1160
4	$0.1147	$0.1043	$0.0699	$0.0681	$0.0419	$0.0477	$0.0852
5	$0.1249	$0.1144	$0.0801	$0.0783	$0.0477	$0.0445	$0.0783
6	$0.1626	$0.1521	$0.1177	$0.1160	$0.0852	$0.0783	$0.0660

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0018

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Fifteenth Revised Sheet No. 23B : Effective

Superseding: Fourteenth Revised Sheet No. 23B

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-G

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14
4	$12.53		$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09		$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59		$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
L		$0.00						
1	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
3	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
4	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
5	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
6	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Maximum Reservation Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.10		$6.45	$9.06	$10.53	$12.22	$14.09	$16.59
L		$2.71						
1	$6.66		$4.92	$7.62	$9.08	$10.77	$12.64	$15.15
2	$9.06		$7.62	$2.86	$4.32	$6.32	$7.89	$10.39
3	$10.53		$9.08	$4.32	$2.05	$6.08	$7.64	$10.14

4	$12.53	$11.08	$6.32	$6.08	$2.71	$3.38	$5.89
5	$14.09	$12.64	$7.89	$7.64	$3.38	$2.85	$4.93
6	$16.59	$15.15	$10.39	$10.14	$5.89	$4.93	$3.16

Minimum Base Reservation Rates The minimum FT-G Reservation Rate is $0.00 per Dth

----

Notes:

1/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2008 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

2/ Maximum rates are inclusive of base rates and above surcharges.

Fifteenth Revised Sheet No. 23C : Effective

Superseding: Fourteenth Revised Sheet No. 23C

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-G

Base Commodity Rate

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0880	$0.0978	$0.1118	$0.1231	$0.1608
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1014	$0.1126	$0.1503
2	$0.0880		$0.0776	$0.0433	$0.0530	$0.0681	$0.0783	$0.1159
3	$0.0978		$0.0874	$0.0530	$0.0366	$0.0663	$0.0765	$0.1142
4	$0.1129		$0.1025	$0.0681	$0.0663	$0.0401	$0.0459	$0.0834
5	$0.1231		$0.1126	$0.0783	$0.0765	$0.0459	$0.0427	$0.0765
6	$0.1608		$0.1503	$0.1159	$0.1142	$0.0834	$0.0765	$0.0642

Minimum
Commodity Rates 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0126	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0457		$0.0687	$0.0898	$0.0996	$0.1136	$0.1249	$0.1626
L		$0.0304						
1	$0.0687		$0.0590	$0.0794	$0.0892	$0.1032	$0.1144	$0.1521
2	$0.0898		$0.0794	$0.0451	$0.0548	$0.0699	$0.0801	$0.1177

3	$0.0996	$0.0892	$0.0548	$0.0384	$0.0681	$0.0783	$0.1160
4	$0.1147	$0.1043	$0.0699	$0.0681	$0.0419	$0.0477	$0.0852
5	$0.1249	$0.1144	$0.0801	$0.0783	$0.0477	$0.0445	$0.0783
6	$0.1626	$0.1521	$0.1177	$0.1160	$0.0852	$0.0783	$0.0660

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0018

2/ The applicable fuel retention percentages are listed on Sheet No. 29, provided that for service rendered solely by displacement, shipper shall render only the quantity of gas associated with losses of .5%.

Sixteenth Revised Sheet No. 27 : Effective

Superseding: Fifteenth Revised Sheet No. 27

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (ACA)	(TCSM)	(PCB) 2/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA						
Deliverability Rate	$2.02			$0.00	$2.02	
Space Rate	$0.0248			$0.0000	$0.0248	
Injection Rate	$0.0053				$0.0053	1.49%
Withdrawal Rate	$0.0053				$0.0053	
Overrun Rate	$0.2427				$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA						
Deliverability Rate	$1.15			$0.00	$1.15	
Space Rate	$0.0185			$0.0000	$0.0185	
Injection Rate	$0.0102				$0.0102	1.49%
Withdrawal Rate	$0.0102				$0.0102	
Overrun Rate	$0.1380				$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA						
Space Rate	$0.0848			$0.0000	$0.0848	
Injection Rate	$0.0102				$0.0102	1.49%
Withdrawal Rate	$0.0102				$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA						
Space Rate	$0.0993			$0.0000	$0.0993	
Injection Rate	$0.0053				$0.0053	1.49%
Withdrawal Rate	$0.0053				$0.0053	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2008 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

Excess Withdrawal Rate	$0.7800	$0.0019		$0.7819	
SS-NE					

Deliverability	$6.71		$0.00	$6.71	
Space Rate	$0.0132		$0.0000	$0.0132	
Injection Rate	$0.0102			$0.0102	3.25%
Withdrawal Rate	$0.0936			$0.0936	
Excess Withdrawal Rate	$1.1600	$0.0019		$1.1619	

1/ The quantity of gas associated with losses is 0.5%.

2/ PCB adjustment surcharge originally effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, was revised and the PCB Adjustment Period has been extended until June 30, 2006 as required by the Stipulation and Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

First Revised Sheet No. 29 : Effective
Superseding: Substitute Original Sheet No. 29

FUEL AND LOSS RETENTION PERCENTAGE 1\,2\, 3\

NOVEMBER - MARCH

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.89%		2.79%	5.16%	5.88%	6.79%	7.88%	8.71%
L		1.01%						
1	1.74%		1.91%	4.28%	4.99%	5.90%	6.99%	7.82%
2	4.59%		2.13%	1.43%	2.15%	3.05%	4.15%	4.98%
3	6.06%		3.60%	1.23%	0.69%	2.64%	3.69%	4.52%
4	7.43%		4.97%	2.68%	3.07%	1.09%	1.33%	2.17%
5	7.51%		5.05%	2.76%	3.14%	1.16%	1.28%	2.09%
6	8.93%		6.47%	4.18%	4.56%	2.50%	1.40%	0.89%

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.88%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

1\ Included in the above Fuel and Loss Retention Percentages is the quantity of gas associated with losses of 0.5%.

2\ For service that is rendered entirely by displacement shipper shall render only the quantity of gas associated with losses of 0.5%.

3\ The above percentages are applicable to (IT) Interruptible Transportation, (FT-A) Firm Transportation, (FT-GS) Firm Transportation-GS, (PAT) Preferred Access Transportation, (IT-X) Interuptible Transportation-X, (FT-G) Firm Transportation-G, (EDS/ERS) FT- A Extended Transportation Service.

Ninth Revised Sheet No. 10 : Effective

Superseding: Eighth Revised Sheet No. 10

CURRENTLY EFFECTIVE RATES

Each rate set forth in this Tariff is the currently effective rate pertaining to the particular rate schedule to which it is referenced, but each such rate is separate and independent and the change in any such rate shall not thereby effect a change in any other rate or rate schedule.

	Base Rate Per Dt	Adjustments Sec. 24	Adjustments Sec. 25	Maximum Rate Per Dt	Minimum Rate Per Dt	Fuel Reimbursement
	(1)	(2)	(3)	(4)	(5)	(6)
RATE SCHEDULE FT						
Field Zone to Zone 2						
- Reservation Rate	$ 9.7097	-	$ 0.2800	$ 9.9897	-	-
- Usage Rate (1)	0.0141	-	-	0.0141	$ 0.0141	2.25% (2)
- Overrun Rate (3)	0.3192	-	0.0092	0.3284	-	-
Zone 1A to Zone 2						
- Reservation Rate	$ 6.0096	-	$ 0.1900	$ 6.1996	-	-
- Usage Rate (1)	0.0117	-	-	0.0117	$ 0.0117	1.86% (2)
- Overrun Rate (3)	0.1976	-	0.0062	0.2038	-	-
Zone 1B to Zone 2						
- Reservation Rate	$ 4.5557	-	$ 0.1900	$ 4.7457	-	-
- Usage Rate (1)	0.0062	-	-	0.0062	$ 0.0062	0.86% (2)
- Overrun Rate (3)	0.1498	-	0.0062	0.1560	-	-
Zone 2 Only						
- Reservation Rate	$ 3.4350	-	$ 0.1900	$ 3.6250	-	-
- Usage Rate (1)	0.0011	-	-	0.0011	$ 0.0011	0.60% (2)
- Overrun Rate (3)	0.1129	-	0.0062	0.1191	-	-
Field Zone to Zone 1B						
- Reservation Rate	$ 8.4890	-	$ 0.2800	$ 8.7690	-	-
- Usage Rate (1)	0.0130	-	-	0.0130	$ 0.0130	1.95% (2)
- Overrun Rate (3)	0.2791	-	0.0092	0.2883	-	-
Zone 1A to Zone 1B						
- Reservation Rate	$ 4.7889	-	$ 0.1900	$ 4.9789	-	-
- Usage Rate (1)	0.0106	-	-	0.0106	$ 0.0106	1.56% (2)
- Overrun Rate (3)	0.1574	-	0.0062	0.1636	-	-
Zone 1B Only						
- Reservation Rate	$ 3.3350	-	$ 0.1900	$ 3.5250	-	-
- Usage Rate (1)	0.0051	-	-	0.0051	$ 0.0051	0.56% (2)
- Overrun Rate (3)	0.1096	-	0.0062	0.1158	-	-
Field Zone to Zone 1A						
- Reservation Rate	$ 7.3683	-	$ 0.2800	$ 7.6483	-	-

- Usage Rate (1)	0.0079	-	-	0.0079	$ 0.0079	1.69% 2)
- Overrun Rate (3)	0.2422	-	0.0092	0.2514	-	-
Zone 1A Only						
- Reservation Rate	$ 3.6682	-	$ 0.1900	$ 3.8582	-	-
- Usage Rate (1)	0.0055	-	-	0.0055	$ 0.0055	1.30% (2)
- Overrun Rate (3)	0.1206	-	0.0062	0.1268	-	-
Field Zone Only						
- Reservation Rate	$ 3.7001	-	$ 0.0900	$ 3.7901	-	-
- Usage Rate (1)	0.0024	-	-	0.0024	$ 0.0024	0.69% (2)
- Overrun Rate (3)	0.1216	-	0.0030	0.1246	-	-
Gathering Charge (All Zones)						
- Reservation Rate	$ 0.3257			$ 0.3257		
- Overrun Rate (3)	0.0107			0.0107		

(1) Excludes Section 21 Annual Charge Adjustment: $0.0018
(2) Fuel reimbursement for backhauls is 0.41%
(3) Maximum firm volumetric rate applicable for capacity release

Atmos Energy Corporation
Basis for Indexed Gas Cost
For the Quarter of November 2006 - January 2007
2006-00000

The projected commodity price was provided by the Gas Supply Department and was based upon the following:

A. **The Gas Supply Department reviewed the NYMEX futures close prices for the quarter of** November 2006 - January 2007 during the period September 11, 2006 through September 19, 2006 **which are listed below:**

		NOV 2006 ($/MMBTU)	DEC 2006 ($/MMBTU)	JAN 2007 ($/MMBTU)
Monday	11-Sep	7.255	9.110	9.825
Tuesday	12-Sep	7.274	8.884	9.639
Wednesday	13-Sep	7.084	8.679	9.404
Thursday	14-Sep	6.467	8.047	8.772
Friday	15-Sep	6.364	7.774	8.504
Monday	18-Sep	6.256	7.806	8.336
Tuesday	19-Sep	6.203	7.883	8.443
		$6.700	$8.312	$8.989

B. Gas Supply believes prices will remain stable and prices for the quarter of Nov 2006 - Jan 2007 **will settle at 8.581 per Mmbtu for the period that the GCA is to be effective.**

In support of Item B, a worksheet entitled "Estimated Weighted Average Cost of Gas" has been filed under a **Petition for Confidentiality in this Case.**

Atmos Energy Corporation
Kentucky Division
For the Month of August, 2006

For Kentucky customers served in:			Indexed 1 Cash-out Price		Transport Charge 2, 3		WKG Cash-out Price
A. Texas Gas:							
	Zone 2 Area	100% of Index Price	$6.9990	+	$0.0478	=	$7.0468
		90% of Index Price	6.2991	+	0.0478	=	6.3469
		80% of Index Price	5.5992	+	0.0478	=	5.6470
	Zone 3 Area	100% of Index Price	$6.9990	+	$0.0508	=	$7.0498
		90% of Index Price	6.2991	+	0.0508	=	6.3499
		80% of Index Price	5.5992	+	0.0508	=	5.6500
	Zone 4 Area	100% of Index Price	$6.9990	+	$0.0632	=	$7.0622
		90% of Index Price	6.2991	+	0.0632	=	6.3623
		80% of Index Price	5.5992	+	0.0632	=	5.6624
B. Tennessee Gas:							
	Zone 2 Area	100% of Index Price	$7.1713	+	$0.0916	=	$7.2629
		90% of Index Price	6.4542	+	0.0916	=	6.5458
		80% of Index Price	5.7370	+	0.0916	=	5.8286

[1] Indexed cash-out price is from the pipeline's Electronic Bulletin Board.

[2] Transport charge used for Texas Gas is its tariff sheet no. 20 commodity rate.

[3] Transport charge used for Tennessee Gas is its tariff sheet no. 23A maximum commodity rate from zone 0 to zone 2.

Atmos Energy Corporation
Correction Factor (CF)
For the Three Months Ended July 1, 2006
Case No. 2006-000

Line No.	(1) Month	(2) Actual Sales Volume (Mcf)	(3) Recoverable Gas Cost	(4) Actual Recovered Gas Cost	(5) Under (Over) Recovery Amount	(6) Adjustments	(7) Total
1	May-06	721,819	3,315,840.91	6,613,148.87	(3,297,307.96)	0.00	(3,297,307.96)
2							
3	June-06	515,369	5,256,810.98	5,039,018.24	217,792.74	0.00	217,792.74
4							
5	July-06	533,668	4,202,910.38	4,139,324.70	63,585.68	0.00	63,585.68
6							
7							
8							
9							
10							
11							
12							
13	Total Gas Cost						
14	Under/(Over) Recovery		12,775,562.27	15,791,491.81	(3,015,929.54)	0.00	(3,015,929.54)
15							
16							
17							
18	Account 191 Balance @ April, 2006						($3,320,396.77)
19							
20	Total Gas Cost Under/(Over) Recovery for the three months ended July, 2006						(3,015,929.54)
21	Recovery from outstanding Correction Factor (CF)						473,388.76
22	Account 191 Balance @ July, 2006						(5,862,937.55)
23							
24							
25							
26							
27							
28	Derivation of Correction Factor (CF):						
29							
30	Account 191 Balance					($5,862,938)	
31	Divided By: Total Expected Customer Sales					18,983,274	MCF
32							
33	**Correction Factor (CF)**					**($0.3088)**	**/MCF**
34							
35							

Atmos Energy Corporation
Recoverable Gas Cost Calculation
For the Three Months Ended July 1, 2006
Case No. 2006-000

Line No.	Description	Unit	GL Jun-06 (1) Month May-06	GL Jul-06 (2) Month June-06	GL Aug-06 (3) Month July-06	Source Document
1	**Supply Volume**					
2	Pipelines:					
3	Texas Gas Transmission [1]	Mcf	0	0	0	
4	Tennessee Gas Pipeline [1]	Mcf	0	0	0	
5	Trunkline Gas Company [1]	Mcf	0	0	0	
6	Midwestern Pipeline [1]	Mcf	0	0	0	
7	**Total Pipeline Supply**	Mcf	0	0	0	
8	Total Other Suppliers	Mcf	2,612,006	2,241,469	2,224,323	pages 5
9	Off System Storage					
10	Texas Gas Transmission	Mcf	0	0	0	
11	Tennessee Gas Pipeline	Mcf	(212,261)	(211,267)	(216,579)	
12	System Storage					
13	Withdrawals	Mcf	224	15	1	
14	Injections	Mcf	(422,998)	(542,466)	(456,415)	
15	Producers	Mcf	11,939	13,272	17,011	
16	Pipeline Imbalances cashed out	Mcf	0	0	0	
17	System Imbalances [2]	Mcf	(1,267,091)	(985,654)	(1,034,673)	
18	**Total Supply**	Mcf	721,819	515,369	533,668	
19						
20	Change in Unbilled	Mcf				
21	Company Use	Mcf	0	0	0	
22	Unaccounted For	Mcf	0	0	0	
23	**Total Sales**	Mcf	721,819	515,369	533,668	

[1] Includes settlement of historical imbalances and prepaid items.

[2] Includes Texas Gas No-Notice Service volumes and monthly imbalances related to transportation customer activities.

Atmos Energy Corporation
Recoverable Gas Cost Calculation
For the Three Months Ended July 1, 2006
Case No. 2006-000

Line No.	Description	Unit	GL Jun-06 (1) Month May-06	Jul-06 (2) Month June-06	Aug-06 (3) Month July-06	Source Document
1	**Supply Cost**					
2	Pipelines:					
3	Texas Gas Transmission [1]	$	1,203,800	1,162,507	1,193,976	
4	Tennessee Gas Pipeline [1]	$	243,294	200,554	197,291	
5	Trunkline Gas Company [1]	$	7,899	7,644	7,899	
6	Midwestern Pipeline [1]	$	0	0	0	
7	**Total Pipeline Supply**	$	1,454,993	1,370,705	1,399,166	
8	Total Other Suppliers	$	17,706,444	13,767,674	13,360,911	page 5
9	Hedging Settlements		0	0	0	
10	Off System Storage					
11	Texas Gas Transmission	$	0	0	0	
12	Tennessee Gas Pipeline	$	(1,432,974)	(1,289,419)	(1,302,874)	
13	WKG Storage		(22,500)	(22,500)	(22,500)	
14	System Storage					
15	Withdrawals	$	1,736	116	8	
16	Injections	$	(2,820,315)	(3,323,042)	(2,730,995)	
17	Producers	$	80,276	81,255	104,241	
18	Pipeline Imbalances cashed out	$	0	0	0	
19	System Imbalances [2]	$	(11,796,820)	(5,472,978)	(6,750,048)	
20	**Sub-Total**	$	3,315,841	5,256,811	4,202,910	
21						
22	Change in Unbilled	$				
23	Company Use	$	0	0	0	
24	Recovered thru Transportation	$	0	0	0	
25	**Total Recoverable Gas Cost**	$	3,315,841	5,256,811	4,202,910	

[1] Includes demand charges, cost of settlement of historical imbalances and prepaid items.

[2] Includes Texas Gas No-Notice Service volumes and monthly imbalances related to transportation customer activities.

Atmos Energy Corporation
Recovery from Correction Factors (CF)
For the Three Months Ended July, 2006
Case No. 2006-000

Exhibit D

Line No.	Month	Type of Sales	Mcf Sold	Rate	Amount
1	May-06	G-1 Sales	650,371.8	$0.2988	$194,331.08
2		G-1 HLF	0.0	0.2988	0.00
3		G-2 Sales	29,851.3	0.2988	8,919.57
4		T-3 Overrun Sales	0.0	0.3287	0.00
5		T-4 Overrun Sales	203.0	0.3287	66.73
6		LVS-1 Sales	0.0	0.0000	0.00
7		LVS-2 Sales	5,111.0	0.0000	0.00
8		LVS HLF Sales	0.0	0.0000	0.00
9		Total	685,537.1		203,317.38
10					
11	June-06	G-1 Sales	468,011.2	$0.2988	$139,841.76
12		G-1 HLF	0.0	0.2988	0.00
13		G-2 Sales	23,247.5	0.2988	6,946.36
14		T-3 Overrun Sales	338.0	0.3287	111.10
15		T-4 Overrun Sales	3,421.0	0.3287	1,124.48
16		LVS-1 Sales	0.0	0.0000	0.00
17		LVS-2 Sales	4,583.0	0.0000	0.00
18		LVS HLF Sales	0.0	0.0000	0.00
19		Total	499,600.7		148,023.70
20					
21	July-06	G-1 Sales	371,178.7	$0.2988	$110,908.18
22		G-1 HLF	0.0	0.2988	0.00
23		G-2 Sales	36,496.5	0.2988	10,905.14
24		T-3 Overrun Sales	301.0	0.3287	98.94
25		T-4 Overrun Sales	412.0	0.3287	135.42
26		LVS-1 Sales	0.0	0.0000	0.00
27		LVS-2 Sales	(13.0)	0.0000	0.00
28		LVS HLF Sales	0.0	0.0000	0.00
29		Total	408,375.2		122,047.68
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	Total Recovery from Correction Factor (CF)				$473,388.76
51					
52	LVS sales commodity is "trued-up" according to Section 3(f) in LVS tariff in P.S.C. No. 1.				
53					
54	When Carriage (T-3 and T-4) customers have a positive imbalance that has been approved by the				
55	Company, the customer is billed for the imbalance volumes at a rate equal to 110% of the Company's				
56	applicable sales rate according to Section 6(a) of P.S.C. No. 20, Sheet Nos. 41A and 47A.				

Atmos Energy Corporation
Detail Sheet for Supply Volumes & Costs
Traditional and Other Pipelines

		May, 2006		June, 2006		July, 2006	
	Description	MCF	Cost	MCF	Cost	MCF	Cost
1	**Texas Gas Pipeline Area**						
2	LG&E Natural						
3	Atmos Energy Marketing, LLC						
4	Texaco Gas Marketing						
5	CMS						
6	WESCO						
7	Southern Energy Company						
8	Union Pacific Fuels						
9	Atmos Energy Marketing, LLC						
10	Engage						
11	ERI						
12	Prepaid						
13	Reservation						
14	Hedging Costs - All Zones						
15							
16	**Total**	2,264,774	$15,344,426.19	1,923,373	$0.00	1,905,827	$11,437,334.17
17							
18							
19	**Tennessee Gas Pipeline Area**						
20	Atmos Energy Marketing, LLC						
21	Union Pacific Fuels						
22	WESCO						
23	Prepaid						
24	Reservation						
25	Fuel Adjustment						
26							
27	**Total**	317,051	$2,152,790.50	288,893	$13,585,247.94	288,616	$1,747,695.04
28							
29							
30	**Trunkline Gas Company**						
31	Atmos Energy Marketing, LLC						
32	Engage						
33	Prepaid						
34	Reservation						
35	Fuel Adjustment						
36							
37	**Total**	30,181	$209,227.64	29,203	$182,425.66	30,114	$177,358.83
38							
39							
40	**Midwestern Pipeline**						
41	Atmos Energy Marketing, LLC						
42	LG&E Natural						
43	Anadarko						
44	Prepaid						
45	Reservation						
46	Fuel Adjustment						
47							
48	**Total**	0	$0.00	0	$0.00	(234)	($1,476.64)
49							
50							
51	**All Zones**						
52	Total	2,612,006	$17,706,444.33	2,241,469	$13,767,673.60	2,224,323	$13,360,911.40
53							
54							
55		**** Detail of Volumes and Prices Has Been Filed Under Petition for Confidentiality ****					

Atmos Energy Corporation
Refund Factor
Case No. 2006-00000

Exhibit E
Page 1 of 1

Line No.	Amounts Reported:	(1) Demand	(2) Commodity	(3) Total	AMOUNT
1	Refund: Texas Gas, Docket No. RP05-317				$ (1,023,588.99)
2	Estimated Interest from 7/12/06 to 10/31/06				(14,733.91)
3					
4					
5	Total				$ (1,038,322.90)
6					
7					
8	Total				$ (1,038,322.90)
9	Less: amount related to specific end users				0.00
10	Amount to flow-through				$ (1,038,322.90)
11					
12	Average of the 3-Month Commercial Paper Rates for the immediately				4.6817%
13	preceding 12-month period less 1/2 of 1% to cover the costs of refunding.				
14					
15		(1)	(2)	(3)	
16	**Allocation**	**Demand**	**Commodity**	**Total**	
17	Texas Gas, Docket No. RP05-317		(1,038,323)	(1,038,323)	
18	Carry-over (Case No. 2003-00377)	0	(260)	(260)	
19	Carry-over (Case No. 2004-00269)		(501)	(501)	
20	Total (w/o interest)	0	(1,039,084)	(1,039,084)	
21	Interest (Line 20 x Line 12)	0	(48,647)	(48,647)	
22	Total	0	(1,087,731)	(1,087,731)	
23					
24	**PBR Calculation**				
25	Demand Allocator - All				
26	(See Exh. B, p. 9, line 18)	0.1850			
27	Demand Allocator - Firm				
28	(1 - Demand Allocator - All)	0.8150			
29	MCF Sales (annual normalized)				
30	(See Exh. B, p. 9, line 1)	19,631,274			
31	Firm Volumes (normalized)				
32	(See Exh. B, p. 6, col. 1, line 26)	18,983,274			
33	Total Throughput				
34	(See Exh. B, p. 6, col. 1, line 42 - line 40)	20,401,274			
35					
36	Demand Factor - All (Principal)	$ -	$0.0000 / MCF		
37	Demand Factor - All (Interest)	$ -	$0.0000 / MCF		
38	Demand Factor - Firm (Principal)	$ -	$0.0000 / MCF		
39	Demand Factor - Firm (Interest)	$ -	$0.0000 / MCF		
40	Commodity Factor - Principal	($1,039,084)		$ (0.0529) / MCF	
41	Commodity Factor - Interest	($48,647)		$ (0.0025) / MCF	
42	Total Demand Firm Factor				
43	(Col. 2, line 36 + 37 + 38 + 39)		**$0.0000 / MCF**		
44	Total Demand Interruptible Factor				
45	(Col. 2, line 36 + 37)		**$0.0000 / MCF**		
46	*Total Firm Sales Factor*				
47	(Col. 3, line 40 + line 41 + col. 2, line 43)	**$ (0.0554) / MCF**			
48	*Total Interruptible Sales Factor*				
49	(Col. 3, line 40 + line 41 + col. 2, line 45)	**$ (0.0554) / MCF**			
50					

ATMOS ENERGY CORPORATION
Large Volume Sales
For the Period August, 2006

The net monthly rates for Large Volume Sales service is as follows:

Base Charge:

LVS-1 Service	$ 20.00	per Meter
LVS-2 Service	220.00	per Meter
Combined Service	220.00	per Meter

LVS-1:

Firm Service			Simple Margin		Non-Commodity Component [2]		Estimated Weighted Average Commodity Gas Cost		Sales Rate	
First	300 [1]	Mcf @	$ 1.1900	+	$ 1.0572	+	$ 6.1256	=	$ 8.3728	per Mcf
Next	14,700 [1]	Mcf @	0.6590	+	1.0572	+	6.1256	=	7.8418	per Mcf
All over	15,000	Mcf @	0.4300	+	1.0572	+	6.1256	=	7.6128	per Mcf
High Load Factor Firm Service										
Demand				@	4.5576	+	$0.0000	=	$ 4.5576	per Mcf of daily contract demand
First	300 [1]	Mcf @	$ 1.1900	+	$ 0.1839	+	$ 6.1256	=	$ 7.4995	per Mcf
Next	14,700 [1]	Mcf @	0.6590	+	0.1839	+	6.1256	=	6.9685	per Mcf
All over	15,000	Mcf @	0.4300	+	0.1839	+	6.1256	=	6.7395	per Mcf

LVS-2:

Interruptible Service										
First	15,000	Mcf @	$ 0.5300	+	$ 0.1839	+	$ 6.1256	=	$ 6.8395	per Mcf
All over	15,000	Mcf @	0.3591	+	0.1839	+	6.1256	=	6.6686	per Mcf

True-up Adjustment for 7/06 billing period: $ (0.1394) per Mcf

[1] All gas consumed by the customer will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

[2] The Non-Commodity Component is from P.S.C. No. 20 Eighteenth Revised Sheet No. 6, effective August 1, 2006.

Atmos Energy Corporation
Large Volume Sales
Estimated WACOG used for Billing
For the Period August, 2006

Exhibit F

Line No.	Supplier/Type of Service		July-06 (A) Estimated MCF Purchased @14.65	July-06 (B) Estimated Commodity Cost
1	**Estimated Purchases:**			
2	Texas Gas Area		1,905,827	$11,437,334.17
3	Tennessee Gas Area		288,616	1,745,713.18
4	Trunkline Gas Area		30,114	177,358.83
5	Midwestern Gas Area		(234)	(1,476.64)
6	Total Estimated Purchases		2,224,323	13,358,929.54
7				
8	**Transportation Costs:**			
9	Texas Gas Transmission			44,627.11
10	Tennessee Gas Pipeline			42,392.19
11	Trunkline Gas Area			458.80
11	Midwestern Gas Area			
12				
13	Local Production		17,011	101,664.10
14				
15	WKG End-User Cash Outs		7,148	35,112.27
16				
17	Total Current Month Gas Cost		2,248,481	$13,583,184.01
18				
19	Less: Lost & Unaccounted for @	1.38%	31,029	
20				
21	Total Deliveries		2,217,452	$13,583,184.01
22				
23	Estimated LVS Weighted Average Commodity Rate			**$6.1256**

Atmos Energy Corporation
Expected Purchases
LVS Commodity Purchase Basis
For the Period of Nov '06 to Jan '07

Line No.			(1) Mcf	(2) MMbtu	(3) Gas Cost
1	**Texas Gas Area**				
2	No Notice Service		0	0	0
3	Firm Transportation		1,717,268	1,760,200	15,753,261
4	Total Texas Gas Area		1,717,268	1,760,200	15,753,261
5					
6					
7	**Tennessee Gas Area**				
8	FT-A&G Commodity		658,558	684,900	6,292,313
9	FT-GS Commodity		97,981	101,900	987,716
10	Total Tennessee Gas Area		756,539	786,800	7,280,029
11					
12	**Trunkline Gas Area**				
13	Firm Transportation		386,473	400,000	3,535,200
14					
15					
16	**Local Production**				
17	Commodity		59,512	61,000	545,932
18					
19					
20	Expected WKG End-User Cash Outs		0	0	0
21					
22	**Total LVS Commodity Purchase Basis**		2,919,792	3,008,000	27,114,422
23					
24	Lost & Unaccounted for @	1.38%	40,293	41,510	
25					
26	Total Deliveries		2,879,499	2,966,490	27,114,422
27					
28	Estimated LVS Weighted Average Commodity Rate (per MMbtu)				$9.1402
29					
30	Estimated LVS Weighted Average Commodity Rate (per Mcf)				$9.4164
31	(To only be used to calculate commodity credit back on Exhibit B)				
32					
33					

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 201
Witness: Gary Smith

Data Request:

Please provide the calculation of the Performance Based Rate Mechanism for each year since the inception of the mechanism.

Response:

The requested information is shown on the attachment labeled AG DR1-201 ATT, which is being filed subject to the terms of a confidentiality petition accompanying Atmos' responses to the Attorney General's Initial Data Requests.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 202
Witness: Gary Smith

Data Request:

Please provide the Company's original application for the Performance Based Rate Mechanism and all associated testimony and exhibits. Identify any differences between the mechanism proposed and the mechanism approved by the Commission. Also, identify and provide the Commission order approving this mechanism.

Response:

Attached is the Company's Application for the existing Performance Based Rate Mechanism in Case No. 2005-00321, along with the Company's responses to data requests from Commission Staff and the Office of the Attorney General. The Order in this Case, dated February 8, 2006 provides a summary of the Company's proposed changes and those approved by the Commission. Exhibit A of the Application (Attachment 1 to this data request) was granted confidential treatment in the referenced Case, and is provided herein in redacted form. Exhibit A of the Application in Case No. 2005-00321 is filed under a Petition for Confidentiality in this Case.

Attachment 1 - Atmos_ModificationsPBR_072905.pdf

Attachment 2 - Atmos_Response_092105.pdf

Attachment 3 - Atmos_ResponseAG_092105.pdf

Attachment 4 - Atmos_Response_102105.pdf

Attachment 5 - Atmos_ResponseAG_102105.pdf

Attachment 6 - Atmos_Response_010906.pdf

Attachment 7 - PSC_Order_020806.pdf

The Law Offices of

WILSON, HUTCHINSON & POTEAT
611 Frederica Street
Owensboro, Kentucky 42301
Telephone (270) 926-5011
Facsimile (270) 926-9394

William L. Wilson, Jr. bill@whplawfirm.com
Mark R. Hutchinson randy@whplawfirm.com
T. Steven Poteat steve@whplawfirm.com

July 28,2005

RECEIVED

JUL 2 9 2005

PUBLIC SERVICE COMMISSION

Honorable Beth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

Case 2005-00321

Subject: Atmos Energy Corporation/PBR Report
Case No. ~~2001-317~~

Dear Ms. O'Donnell:

Enclosed are an original (non-redacted) and eleven copies (redacted) of the following:

1. Submission of Report and Motion to Modify and Extend Experimental Performance Based Ratemaking Mechanism (PBR);

2. The quantative results of Atmos Energy's PBR program are attached as Exhibit "A" to the enclosed report;

3. Exhibit "B" to the report contains the proposed tariff modifying and extending Atmos Energy's PBR.

As established by the enclosed Report, the PBR continues to be beneficial to both Atmos Energy and its ratepayers. Extending, as modified, the PBR mechanism will continue to provide significant benefits to Atmos Energy's customers, as well as its shareholders. Therefore, the Commission is respectfully requested to approve the modification and extension of the PBR mechanism as proposed herein.

Also enclosed is a Petition for Confidentiality pertaining to the discounts afforded

Atmos Energy through its single source supplier contract with Atmos Energy Marketing, Inc. This information is extremely confidential and has previously been afforded confidential protection by the Commission. This information is both disclosed in, and determinable from, data appearing throughout the quantitative results contained in Exhibit "A". Accordingly, Exhibit "A" has been redacted in its entirety.

Please stamp the eleventh copy and return it in the enclosed envelope. Thanks.

Very truly yours,

Mark R. Hutchinson

MRH:bkk

RECEIVED

JUL 29 2005

PUBLIC SERVICE
COMMISSION

MODIFICATION OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE BASED RATEMAKING MECHANISM (PBR)

CASE NO. ~~2001-317~~

JULY 28, 2005

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

MODIFICATION OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE BASED RATEMAKING MECHANISM (PBR)	)))))	**CASE NO. ~~2001-317~~**

<u>SUBMISSION OF REPORT AND MOTION TO MODIFY AND EXTEND PERFORMANCE BASED RATEMAKING MECHANISM</u>

On June 1, 1998, the Commission entered an Order in Case No. 97-513 approving use by Atmos Energy Corporation ("Atmos Energy" or "Company") of an experimental Performance Based Ratemaking mechanism ("PBR") for a period of three years. By subsequent orders, the Commission ultimately extended the effective period of the Company's PBR until March 31, 2002. Thereafter, in Case No. 2001-317, the Company moved the Commission for an order modifying the original PBR slightly and requesting that it be extended for five (5) years commencing April 1, 2002. On March 25, 2002, the Commission entered an Order in Case No. 2001-317 extending the PBR, as modified, until March 31, 2006. The Commission's Order further required the Company to report on the results of the PBR pilot program and the attached Report is being filed with the Commission in fulfillment of that requirement.

The attached Report establishes that the PBR has proven to be very beneficial to both the Company's ratepayers and its shareholders. Total savings attributable to the PBR for the three (3) year period from April, 2002 through March, 2005 are more than $9,000,000.

Customers have realized gas cost savings of nearly $6,150,000 for that three-year period. Accordingly, Atmos Energy moves the Commission for the entry of an order modifying the Company's current PBR to effectuate a limited number of technical changes to the PBR and extending its applicability, as modified, for an additional term of five (5) years.

In addition, Company also moves the Commission for entry of an Order authorizing a two month interim extension of the current PBR. By way of background, the Commission's Order in this proceeding, dated March 25, 2002, approved the use of Company's PBR for a period ending March 31, 2006. During that period, the Company's entire gas supply has been furnished pursuant to a gas supply contract with Atmos Energy Marketing, Inc. ("AEM"), which was approved by the Commission in Case No. 2002-245. That contract does not expire until June 1,2006. The Company has operated under the assumption that both the PBR and the AEM gas supply contract expired on the same date (June 1, 2006). This was the original intent of the parties to the contract and presumably the intent of the Commission. The Company only recently discovered, while preparing this filing, that the PBR is scheduled to expire on March 31, 2006, as opposed to June 1, 2006, which is the expiration date of the AEM contract. The expiration dates of the PBR and the AEM supply contract need to coincide. Accordingly, the Commission is requested to grant an interim extension of the PBR until June 1,2006. If the Commission concurs that the PBR should be extended for a new multi-year period, the new commencement date for that extension would be June 1, 2006.

WHEREFORE, Western prays: (1) that its Report on the results of the current PBR mechanism be accepted; (2) for entry of an order authorizing a two month interim extension of the Company's current PBR; (3) for entry of an order approving the proposed modifications to the PBR (as described in Section II of the Report) and extending its applicability as modified, for a period of five (5) years, commencing June 1, 2006; and, (4) for entry of an order approving the proposed tariff attached as Exhibit "B".

Respectfully submitted this 28 day of July, 2005.

Mark R. Hutchinson
WILSON, HUTCHINSON & POTEAT
611 Frederica Street
Owensboro, Kentucky 42301
(270) 926-5011

Douglas Walther
Atmos Energy Corporation
P.O. Box 650250
Dallas, Texas 75265

Attorneys for Atmos Energy

CERTIFICATE OF SERVICE

I hereby certify that on the 28 day of July, 2005, the foregoing document, together with ten (10) copies, were filed with the Kentucky Public Service Commission, 211 Sower Boulevard, P.O. Box 615, Frankfort, Kentucky 40602, and a true copy thereof mailed by first class mail to the following named persons:

Elizabeth E. Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capitol Center Drive
Frankfort, Kentucky 40601

Mark R. Hutchinson

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter:

MODIFICATION OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE-BASED RATEMAKING MECHANISM (PBR)	))))	**Case No. 2001-317**

PETITION FOR CONFIDENTIALITY OF CERTAIN INFORMATION BEING FILED WITH THE KENTUCKY PUBLIC SERVICE COMMISSION WITH THE REPORT ON ATMOS ENERGY CORPORATION'S PERFORMANCE BASED RATEMAKING

Atmos Energy Corporation ("Atmos Energy" or Company"), respectfully petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001 §7, and all other applicable law, for confidential treatment of the information contained in the attached documents. In support of this Petition, Atmos Energy states:

1. On June 1, 1998, the Commission entered an Order in Case No. 97-513 approving an Experimental Performance Based Ratemaking Mechanism ("PBR") for a period of three years. By subsequent Orders, the Commission ultimately extended the effective period of the Company's PBR until March 31, 2002. Thereafter, in Case No. 2001-317, the Company moved the Commission for an order modifying the original PBR slightly and requesting that it be extended for five (5) years commencing April 1, 2002. On March 25, 2002, the Commission entered an Order in Case No. 2001-317 extending the PBR, as modified, until March 31, 2006. The Commission's Order

further required the Company to report on the results of the PBR pilot program. The Report being filed with the Commission is in fulfillment of that requirement.

2. The Company's current gas supply contract is with Atmos Energy Marketing, Inc. ("AEM"). It contains significant pricing discounts. In order to fully report to the Commission the results of the Company's current PBR program, disclosure of the discounts on gas purchases provided in the current supply contract is required. In order to protect the confidentiality of that information, not only must the discount themselves be redacted in the non-confidential version, but all information from which the discount could be calculated, must likewise be redacted.

3. This information has previously been determined by the Commission (in this proceeding) to be entitled to confidential protection. Nothing has occurred since the Commission granted confidential protection to this type of information that would now disqualify it from protection. The Company accordingly petitions the Commission to again treat this information as confidential.

4. Pursuant to KAR 5:001, Section 7 (3), temporary confidentiality of the information sought to be protected herein should be maintained until the Commission enters an order as to the Petition. Once the order regarding confidentiality has been issued, the Company would have twenty (20) days to seek alternative remedies pursuant to 807 KAR 5:001, Section 7 (4).

WHEREFORE, Company petitions the Commission to treat as confidential the information contained in the attached.

Respectfully submitted this 28th day of July, 2005.

Mark R. Hutchinson
WILSON, HUTCHINSON & PLAIN
611 Frederica Street
Owensboro, Kentucky 42301

Douglas Walther
Atmos Energy Corporation
P.O. Box 650250
Dallas, Texas 75265

Attorneys for Atmos Energy Corporation

By:________________________

VERIFICATION

I, Gary Smith, being duly sworn under oath state that I am Vice President of Rates and Regulatory Affairs for Atmos Energy Corporation, and that the statements contained in the foregoing Petition are true as I verily believe.

____
Gary Smith

CERTIFICATE OF SERVICE

I hereby certify that on the 28 day of July, 2005, the original of this Petition for Confidentiality of Certain Information for which confidential treatment is sought, together with ten (10) copies of the Petition without the confidential information, were filed with the Kentucky Public Service Commission, 211 Sower Boulevard, P.O. Box 615, Frankfort, Kentucky 40602, and a true copy thereof mailed by first class mail to the following named persons on this the 28 day of July, 2005:

Elizabeth Blackford
Assistant Attorney General
Office of Rate Intervention
1024 Capitol Center Drive
Frankfort, Kentucky 40601

____
Mark R. Hutchinson

ATMOS ENERGY CORPORATION

REPORT ON PERFORMANCE-BASED RATEMAKING
REPORT PERIOD: APRIL 2002 – MARCH 2005
KPSC CASE NO. 2001-00317

JULY 28, 2005

Introduction

This report is designed to fulfill the requirements of the Commission's Order dated March 25, 2002 in this Case whereby Atmos Energy Corporation ("Atmos Energy" or the "Company") is required to report on the results of the initial three (3) years of the four (4) year program. This report consists of three sections. Section I of this narrative provides an overview and description of Atmos Energy's approach to gas supply purchasing under the Performance Based Ratemaking ("PBR") program and the specific performance of the existing PBR mechanism and supply agreement. Section II outlines the Company's forward-looking proposals under the PBR. Section III discusses Atmos Energy's proposed five-year extension of the PBR and proposed future reporting.

I. Overview & Approach to Gas Supply Purchasing Under the PBR

A. <u>Overview and Background</u>

On December 19, 1997, Atmos Energy (then Western Kentucky Gas Company) filed with the Kentucky Public Service Commission (the "Commission"), a proposal to implement a PBR mechanism for three years. The PBR was designed to create a system of rewards and penalties that would encourage the Company to acquire low cost supplies of natural gas. Actual costs are compared to an established benchmark of costs, generally based on market prices for gas, and any excess costs or savings are shared between shareholders and customers. The PBR also serves to streamline the review of the reasonableness of gas procurement costs. On June 1, 1998, the Commission approved Atmos Energy's proposal with slight modifications. On December 14, 1998, the Commission approved a request by the Company to change the commencement date of the PBR to July 1, 1998 to synchronize the start of the PBR with the effective date of the new gas supply contract entered into as a result of the Commission's PBR approval order.

The original three-year pilot was then to run through June 30, 2001. On April 2, 2001, Atmos Energy filed with the Commission a proposal to extend the three-year pilot through March 31, 2002. On June 15, 2001, the Commission approved the requested extension. On September 28, 2001, Atmos Energy filed with the Commission to extend the PBR program for an additional term of five (5) years, commencing as of April 1, 2002. On March 25, 2002, by Order in Case No. 2001-00317, the Commission approved the PBR program, as modified, for a period of four (4) years. In Case 2002-00245, the Commission approved Atmos Energy's current supply agreement with its affiliate Atmos Energy Marketing (then Woodward Marketing), accepted the Company's request for deviation from KRS 278.2207 and provided guidance for future RFP's issued by the Company for a third-party gas supplier.

B. Atmos Energy's Innovative Approach to Gas Commodity Purchases

Atmos Energy's response to the rewards and penalties established in the PBR mechanism was to develop a prudent and beneficial gas supply contract that would assure the Company's continued long-term success in purchasing gas commodity. In designing such a contract Atmos Energy assumed that several key provisions were necessary in order to maximize savings:

- The contract must be competitively bid in order to minimize price,
- A single-source supply contract would generate greater volume discounts,
- A comprehensive gas supply contract would encourage bids without supply reservation fees,
- Maximizing the term of the contract and the "opportunities" available to potential bidders under the contract would further maximize volume discounts of the bids, and
- The contract must be expressed in price terms that mirror the pre-established benchmarks under the PBR in order to assure measurability of savings or costs against those benchmarks.

Further, Atmos Energy believed that retaining key operational controls and establishing strict performance requirements for the supplier would be necessary to ensure that by limiting itself to a single source of supply it would not be jeopardizing the reliability of its supply, particularly during periods of peak demand.

Ultimately, the Company developed a Request for Proposal ("RFP") and solicited bids from a large number of reputable suppliers who might be interested and capable of providing highly competitive bids under the sophisticated terms proscribed in the RFP.

The key features of the RFP reflected the assumptions noted above. Among those key features were:

- A four-year contract (striving to coincide with the authorized term of the PBR extension period),
- A single source provider for all of Atmos Energy's firm system supply (approximated at 20.4 Bcf, including 11.4 Bcf of pipeline and on-system storage),
- A single contract price per delivered unit of first-of-the-month commodity gas purchases to be bid as a discount or premium to the simple arithmetic average of the "basket" of indices (NYMEX, Inside FERC, Natural Gas Week and Gas Daily) established in the PBR,
- Intra-month swing gas commodity purchases benchmarked against Gas Daily only,
- No provision for supply reservation fees,
- Assignment of the management of all of Atmos Energy's Kentucky firm transportation and storage contracts to the sole supplier as a "value-added" contract feature,
- Assumed storage injection and withdrawal in accordance with seasonal plans, and
- A commission of ten percent (10%) paid to the supplier to encourage capacity release of unused firm transportation and storage contracts.

The objective of Atmos Energy's "full-requirements" contract was to extract the lowest cost bid possible from potential bidders through the enticement offered by the largest and most comprehensive contract possible. The RFP combined the Company's full firm gas commodity requirements with all of its transportation and storage contracts. Hence, potential suppliers were assured of the opportunity to supply Atmos Energy's large, firm market for four years plus the additional opportunity to leverage the substantial transportation capacity and storage assets beyond the actual supply requirements of that market from time to time. when operationally feasible. In particular, the assignment of the management of Atmos Energy's transportation and storage assets to the potential supplier was viewed as a "value-added" feature that would encourage an additional level of discounting by bidders. Despite the breadth and supplier flexibility inherent in a "full-requirements" contract, the Company also retained full operational control through mandatory compliance with a prescribed seasonal storage and operational plan, and non-performance penalties and remedies.

Atmos Energy's contract excludes any supply reservation fees. Reservation fees are often charged by wholesale gas suppliers in order to reserve up to certain volumes for delivery to the LDC when needed. In essence, a reservation fee is payment for gas supply "call rights" which may or may not be needed by the LDC. Although reservation fees are a common feature in LDC gas contracts, the successful bids for this contract excluded reservation fees. Historically, Atmos Energy paid a variety of suppliers reservation fees (based on the prevailing rate of gas) in order to ensure its ability to "call" up to certain contract quantities and guarantee supply during periods of heavy demand. Atmos Energy was able to avoid reservation costs by establishing a comprehensive, full requirements gas supply contract which included an asset management feature that provided the supplier with known volumes for delivery under the contract.

Ultimately, the value inherent in Atmos Energy's innovative RFP was exhibited through the receipt of significantly discounted bids for commodity gas purchases. The discounted cost of gas obtained through this bidding process ultimately accounted for a majority of the savings generated under the PBR during program's seven (7) years of existence.

C. Atmos Energy's Innovative Approach to Transportation Purchases

Primarily, Atmos Energy's approach to the Transportation Cost Component of the PBR was to seek out and negotiate the largest possible discounts from FERC-approved transportation rates with its existing pipeline suppliers. The Transportation Cost Component also encouraged the Company to generate capacity release revenues.

1. Pipeline Discounts

It is difficult for Atmos Energy to obtain pipeline discounts. The Company does not have abundant access to alternative pipeline supply sources. Over many decades, Atmos Energy's Kentucky system was constructed along the Texas Gas and Tennessee Gas pipelines because those were the only alternatives available to obtain our supply. The Company's markets are rural and dispersed, and not integrated in such a way that has encouraged more pipelines into our region whereby alternative access would be made available. To the extent new capacity has been constructed into our region that capacity has been dedicated to larger urban markets. Nevertheless, even with a lack of access to broad pipeline alternatives, Atmos Energy has been able to secure some service on a limited basis from Trunkline, Midwestern and ANR pipelines. As existing pipeline contracts have come up for extension or re-negotiation, Atmos Energy has aggressively used alternative pipeline suppliers and potential service from those alternative suppliers as a bargaining tool to negotiate meaningful discounts. As a result, Atmos Energy has been able to renegotiate transportation capacity arrangements producing more than $2,000,000 in savings during the last three years of the program and more than $4,000,000 since the program's inception. The Company always seeks to obtain the lowest cost transportation services for its customers; however, the PBR provides an even greater inducement to seek out and maximize those discounts.

2. Capacity Release

Atmos Energy had been releasing under-utilized pipeline capacity for several years when the PBR began. Hence, as part of the initial PBR, the Commission established a capacity release threshold equivalent to the value of the Company's capacity release revenues in prior years. The Commission eliminated the threshold requirement in the Order for Case No. 2001-00317.

Atmos Energy has established a commission-based sales program within its gas supply contract which ensured its supplier a fixed, ten percent (10%) sales commission for each dollar of capacity released. This approach to marketing capacity release encourages the Company's supplier to continuously market capacity release in order to extract greater value. Capacity Release savings were $1,015,917 for the period April 2002 through March 2005. Total Capacity Release savings are approximately $1,816,000 for the period July 1998 through March 2005.

Ultimately, the improved efficiencies obtained from Atmos Energy's transportation contracts and the savings derived from our supplier's capacity release program resulted in significant savings achieved under Transportation Cost components of the PBR.

D. Atmos Energy's Innovative Approach to Marketing to Off-system Sales

The Off-system Sales mechanism was designed to encourage Atmos Energy to market to non-Atmos Energy customers gas commodity which might be purchased as base load but, from time to time, might not be needed by Atmos Enegy's customers. Like the Capacity Release component of the Transportation Cost mechanism, the Off-system Sales mechanism was designed to encourage the Company to sell an under-utilized resource. In this case, that resource is gas commodity. By crediting half of all Off-system Sales revenue to Atmos Energy's customers, they would incur a lower cost of commodity gas.

To the Company, the Off-system Sales mechanism has represented an opportunity with an uncertain value. Future weather conditions and other consumption factors made the future demand for gas uncertain. Similarly, it was also uncertain what price Atmos Energy could get for its gas at a time when its own customers did not need it. There was also an administrative cost to be borne in order to broker the gas off-system. Like the cost to market Capacity Release, that administrative cost would somewhat offset the value of any Off-system Sales revenue.

To address these uncertainties and minimize any administrative costs to be incurred by the Company, Atmos Energy's RFP was designed to exchange the potential net value of any Off-system Sales which could be generated by assigning the management of Atmos Energy's storage and transportation assets over to its gas supplier. To the extent that Atmos Energy's customers did not require their base load supplies of gas, the gas supplier would be free to market that gas off-system just as the Company could have under the Off-system Sales mechanism. The Commission ordered in Case No. 2001-00317 that the OSSIF to be expanded to include off-system sales of storage services.

E. Observations Regarding Atmos Energy's PBR Mechanism and Supply Model

In conjunction with the renewal of the PBR mechanism, the subsequent RFP process and supplier selection, Atmos Energy received important feedback from the Commission and from Liberty Consulting Group ("Liberty"), which was conducting an audit of gas procurement processes of each of the five largest LDC's in Kentucky on behalf of the Commission at that time.

In Case No. 2002-00245, the Commission approved Atmos Energy's supply contract with its affiliate Atmos Energy Marketing (then Woodward Marketing). The Commission also granted a deviation from affiliate pricing requirements of KRS 278.2207(1)(b) pursuant to KRS 278.2207(2) due to the competitive bidding process employed. Further, the Commission stated that the Company "shall expand and modify any future RFPs it issues for a third-party gas supplier and shall respond to prospective bidders' requests for information as detailed" in that Order. At a minimum, the Commission suggested, the next initial RFP should include daily system throughput, daily operation of on-system storage facilities, and operation of pipeline storage facilities. Also, all supplemental information requested should be provided to all prospective bidders. Despite those suggested improvements, the Order notes that Liberty and the Commission found Atmos Energy's RFP process and its ultimate award of the contract acceptable in that Case.

In the 2002 audit, Liberty noted that Atmos Energy Kentucky Division's (then Western Kentucky Gas) gas supply management has produced good results. Liberty suggested, however, that Atmos Energy's RFP procedures should be improved by:

- Conducting bidder's meetings
- Providing more comprehensive detail in the original RFP
- Adopt procedures for notification of all bidders when questions from one bidder are answered, and
- Ask for proposals for varying periods (such as two-, three- and four-year periods), and then evaluate the best proposal among those options.

Atmos Energy has documented and modified its RFP procedures recognizing the direction provided by the Commission and through the Liberty audit. The revised procedures have been filed with the Commission's Management Audit Branch. The Company has endeavored to implement all improvements to its gas procurement processes identified the Liberty audit. These improvements will be useful in the RFP process to be employed in selecting a gas supplier upon finalizing the PBR renewal benchmarks in this Case.

II. Forward-Looking Proposals

A. Continuation of Existing Mechanisms

With only minor technical modifications, Atmos Energy proposes to retain all of the existing features of its PBR mechanism. Specifically, Atmos Energy proposes to retain the Gas Commodity Cost component mechanism, the Transportation Cost component mechanism, the Off-system Sales component mechanism and the Balance Adjustment. Although the Off-system Sales component mechanism has not been directly utilized during the program, the Company proposes to retain this mechanism should future circumstances support direct utilization of this mechanism.

In support of its proposal, the Company reiterates the following successes of its PBR program:

- Applying the benchmark standards of performance in the PBR, Atmos Energy has produced prudent gas purchases with measurable savings totaling $9,093,513 over the three-year period of April 2002 through March 2005, with the majority of those savings going to customers. Those savings would not have been realized in absence of the PBR mechanism.
- A key feature of the PBR is the establishment of a known, pre-determined, and directly observable benchmarks, the assurance that Atmos Energy's gas procurement performance will be measured against that benchmark, and that rewards or penalties will be determined based upon that benchmark. Foreknowledge of that benchmark gives the Company confidence as to how its behavior will be judged. The assurance of the standard of prudence and the opportunity to share rewards has led the Company to undertake certain risks to create savings under the PBR. In the absence of an incentive plan, such as the PBR, Atmos Energy lacks the appropriate incentives to incur the additional risks without the potential to earn rewards for that behavior.
- Specifically, the PBR induced a beneficial change in Atmos' behavior by encouraging it to test different ways to purchase gas supplies in order to generate shared savings, that it otherwise lacked the incentive to pursue.
- The PBR encouraged Atmos Energy to develop an innovative Request for Proposal (RFP) for its new gas supply contract that directly incorporated the PBR benchmarks and mechanisms.
- Each of the existing PBR mechanisms was directly or indirectly utilized to produce measurable savings. The savings from Off-system Sales mechanism were achieved indirectly through the assignment of the management of the Company's storage and transportation assets as a "value-added" feature of Atmos Energy's gas supply contract.

- The PBR mechanism has encouraged Atmos Energy to save approximately $19,600,000 from July 1998 through March 2005, with the majority of those savings going to customers.

We are confident that by pursuing some of the same innovative approaches to gas supply contracting, within the same context of incentives and penalties, the PBR will produce significant shared savings for Atmos Energy and its customers in subsequent years.

B. Modifications to Existing Mechanisms

Atmos Energy proposes certain adjustments to its existing PBR mechanisms.

Within the computation of Gas Acquisition Index Factor (GAIF), on Tariff Sheet 27, the Company proposes to incorporate a new component called the "GAIFAM", or Gas Acquisition Index Factor for Asset Management. This factor would distinguish and clearly recognize any supplier discounts provided for asset management rights, if any, that are fixed discounts not directly tied to per unit natural gas purchases. With the subsequent RFP to prospective suppliers synchronized with the terms of the PBR mechanism, this addition would clearly allow greater flexibility in the structure of bids by prospective suppliers. As proposed, it is important to note this additional component would be a clear option for the prospective bidders, but not a required feature of their bid.

Also within the computation of the Gas Acquisition Index Factor (GAIF), the Company proposes the following technical changes to reflect naming changes in the respective indices:

- Tariff Sheet 29, SAIBL (TGT-1), I(1), Natural Gas Week, change "North Louisiana" to "Louisiana",
- Tariff Sheet 29, SAIBL (TGPL-0), I(2), Gas Daily, change "Texas South – Corpus Christi – Tennessee and East Texas – North Louisiana Area – Tennessee, 100 leg averaged for the month" to "South – Corpus Christi – Tennessee, Zone 0".

- Tariff Sheet 29, SAIBL (TGPL-0), I(3), Inside FERC – Gas Market Report, change "Tennessee Zone 0" to "Texas Zone 0".
- Tariff Sheet 30, DAIBL (TGT-2, 3 & 4), (TGPL-2) and (TGC-1B), I(2), Gas Daily, change "Dominion – South Point" to "Dominion – South Point – Appalachia".
- Tariff Sheet 32, SAISL (TGPL-0), I(3), Gas Daily, change "Texas South – Corpus Christi – Tennessee and East Texas – North Louisiana Area – Tennessee, 100 leg averaged for the month" to "South – Corpus Christi – Tennessee, Zone 0".
- Tariff Sheet 33, DAISL (TGT-2, 3 & 4), (TGPL-2) and (TGC-1B), I(1), Gas Daily, change "Dominion – South Point" to "Appalachia, Dominion – South Point".

Also, Atmos Energy proposes to decrease the Percentage of Total Actual Gas Supply Costs (PTAGSC) from the current 2% threshold to a 1% threshold. Market prices today are drastically higher than when this program was modified in 2002 to include this threshold. When comparing the NYMEX settle prices from the most recent twelve months to calendar year 2002, prices have risen approximately 103% which is out of Atmos Energy's control. The PBR was designed to reward the Company for minimizing the market charges for natural gas commodity and maximizing gas cost savings through innovative deal structures, but under current market conditions, the Company's hurdle for 50% sharing has, in essence, doubled. Atmos Energy believes that by lowering the threshold from 2% to 1%, the PBR program will recognize current market conditions and adjust the threshold to the same relative level originally established in Case 2001-00317. This change is reflected in Atmos Energy's proposed tariff on Sheet No. 37.

III. Extension Period & Future Reporting

A. Extension Period

Atmos Energy's original PBR mechanism was established for an experimental period of three years, and then was extended for an additional four years. This report shows that during the six (6) years the PBR mechanism has been in existence, the program has resulted in significant savings for customers. Therefore, the Company proposes to extend its PBR mechanism, as modified, for an additional term of five years, through March 31, 2011. A longer term will help ensure meaningful benefits for customers because this PBR mechanism has proven to be effective, and a longer experimental period without the uncertainty of expiration may enable Atmos Energy, and its customers, to achieve greater savings.

Atmos Energy proposes a term for its modified experimental PBR mechanism of five years. However, if an external event occurs, such as an Order or rulemaking of the Federal Energy Regulatory Commission ("FERC"), which clearly and uncontrollably affects the benchmarks or some other aspect of the PBR mechanism, the Company and the Commission should reserve the right to modify or terminate the program.

B. Future Reports

Six months prior to the end of the third experimental program, Atmos Energy proposes to file an assessment and review of the PBR mechanism. Atmos Energy will propose any recommended modifications to the PBR mechanism, and the Commission will be able to review and act upon any proposed changes to the mechanism at that time. Such procedures will add certainty to the nature of the mechanism by establishing a review and approval process with a known timeline.

EXHIBIT B

ATMOS ENERGY CORPORATION

PROPOSED TARIFFS

ATMOS ENERGY CORPORATION

PBR

Experimental Performance Based Rate Mechanism

Applicable

To all gas sold.

Rate Mechanism

The amount computed under each of the rate schedules to which this Performance Based Rate Mechanism is applicable shall be increased or decreased by the Performance Based Rate Recovery Factor (PBRRF) at a rate per 1,000 cubic feet (Mcf) of monthly gas consumption. Demand costs and commodity costs shall be accumulated separately and included in the pipeline suppliers Demand Component and the Gas Supply Cost Component of the Gas Cost Adjustment (GCA), respectively. The PBRRF shall be determined for each 12-month period ended October 31 during the effective term of these experimental performance based ratemaking mechanisms, which 12-month period shall be defined as the PBR period.

The PBRRF shall be computed in accordance with the following formula:

$$PBRRF = (CSPBR + BA) / ES$$

Where:

ES = Expected Mcf sales, as reflected in the Company's GCA filing for the upcoming 12-month period beginning February 1.

CSPBR = Company Share of Performance Based Ratemaking Mechanism savings or expenses. The CSPBR shall be calculated as follows:

$$CSPBR = TPBRR \times ACSP$$

Where:

ACSP = Applicable Company Sharing Percentage

TPBRR = Total Performance Based Ratemaking Results. The TPBRR shall be savings or expenses created during the PBR period. TPBRR shall be calculated as follows:

$$TPBRR = (GAIF + TIF + OSSIF)$$

PBR

Experimental Performance Based Rate Mechanism (Continued)

GAIF

GAIF = Gas Acquisition Index Factor. The GAIF shall be calculated as follows:

$$GAIF = GAIFBL + GAIFSL + GAIFAM$$ (T)

Where:

GAIFBL represents the Gas Acquisition Index Factor for Base Load system supply natural gas purchases.

GAIFSL represents the Gas Acquisition Index Factor for Swing Load system supply natural gas purchases.

GAIFAM represents the Gas Acquisition Index Factor for Asset Management, representing the portion of fixed discounts provided by the supplier for asset management rights, if any, not directly tied to per unit natural gas purchases (T)

GAIFBL

The GAIFBL shall be calculated by comparing the Total Annual Benchmark Gas Commodity Costs for Base Load (TABGCCBL) system supply natural gas purchases for the PBR period to the Total Annual Actual Gas Commodity Costs for Base Load (TAAGCCBL) system supply natural gas purchases during the same period to determine if any shared expenses or shared savings exist.

TABGCCBL represents the Total Annual Benchmark Gas Commodity Costs for Base Load gas purchases and equals the annual sum of the monthly Benchmark Gas Commodity Costs of gas purchased for Base Load (BGCCBL) system supply

BGCCBL represents Benchmark Gas Commodity Costs for Base Load gas purchases and shall be calculated on a monthly basis and accumulated for the PBR period. BGCCBL shall be calculated as follows:

$$BGCCBL = Sum\,[(APVBLi - PEFDCQBL) \times SAIBLi] + (PEFDCQBL \times DAIBL)$$

Where:

APVBL is the Actual Purchased Volumes of natural gas for Base Load system supply for the month. The APVBL shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

PBR

Experimental Performance Based Rate Mechanism (Continued)

"i" represents each supply area.

PEFDCQBL are the Base Load Purchases in Excess of Firm Daily Contract Quantities delivered to Atmos' city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAIBL is the Supply Area Index factor for Base Load to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission-Zone SL), TGT-1 (Texas Gas Transmission-Zone 1), TGPL-0 (Tennessee Gas Pipeline-Zone 0), and TGPL-1 (Tennessee Gas Pipeline-Zone 1), and TGC-ELA (Trunkline Gas Company-ELA).

The monthly SAIBL for TGT-SL, TGT-1, TGPL-0, TGPL-1, and TGC-ELA shall be calculated using the following formula:

$$SAIBL = [I(1) + I(2) + I(3) + I(4)] / 4$$

Where:

"I" represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

The indices for each supply zone are as follows:

<u>SAIBL (TGT-SL)</u>

I (1) is the average of weekly <u>Natural Gas Week</u> postings for Texas Gas Transmission Corporation Zone SL: South Louisiana as Spot Prices on Interstate Pipeline Systems.
I (2) is the average of the daily high and low <u>Gas Daily</u> postings for Louisiana-Onshore South Texas Gas Zone SL averaged for the month.
I (3) is the <u>Inside FERC – Gas Market Report</u> first-of-the-month posting for Texas Gas Zone SL.
I (4) is the <u>New York Mercantile Exchange</u> Settled Closing Price.

PBR

Experimental Performance Based Rate Mechanism (Continued)

SAIBL (TGT-1)

I (1) is the average of weekly Natural Gas Week postings for Texas Gas Transmission Corporation Zone 1: Louisiana as Spot Prices on Interstate Pipeline Systems. (T)
I (2) is the average of the daily high and low Gas Daily postings for East Texas – North Louisiana Area - Texas Gas Zone 1 averaged for the month.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Texas Gas Zone 1.
I (4) is the New York Mercantile Exchange Settled Closing Price.

SAIBL (TGPL-0)

I (1) is the average of weekly Natural Gas Week postings for Tennessee Gas Pipeline Co. Zone 0: South Texas as Spot Prices on Interstate Pipeline Systems.
I (2) is the average of the daily high and low Gas Daily postings for South – Corpus Christi – Tennessee , Zone 0. (T)
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Texas Zone 0. (T)
I (4) is the New York Mercantile Exchange Settled Closing Price.

SAIBL (TGPL-1)

I (1) is the average of weekly Natural Gas Week postings for Tennessee Gas Pipeline Co. Zone 1: South Louisiana as Spot Prices on Interstate Pipeline Systems.
I (2) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South – 500 leg and – 800 leg average for the month.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Tennessee Zone 1.
I (4) is the New York Mercantile Exchange Settled Closing Price.

SAIBL (TGC-ELA)

I (1) is the average of weekly Natural Gas Week postings for Trunkline Gas Co. East Louisiana as Spot Prices on Interstate Pipeline Systems.
I (2) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South, Trunkline ELA.
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Trunkline Louisiana.
I (4) is the New York Mercantile Exchange Settled Closing Price.

ATMOS ENERGY CORPORATION

PBR

Experimental Performance Based Rate Mechanism (Continued)

DAIBL is the Delivery Area Index factor for Base Load to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from Texas Gas Transmission's Zone 2, 3 or 4, Tennessee Gas Pipeline's Zone 2, or Trunkline Gas Company's Zone 1B.

The monthly DAIBL for TGT-2, 3, 4, TGPL-2, and TGC-1B shall be calculated using the following:

$$DAIBL = [I(1) + I(2) + I(3)] / 3$$

DAIBL (TGT-2, 3, & 4), (TGPL-2) and (TGC-1B)

I (1) is the average of weekly Natural Gas Week postings for Spot Prices on Interstate Pipeline Systems for Dominion – South.
I (2) is the average of the daily high and low Gas Daily postings the Daily Price Survey for Dominion – South Point – Appalachia. (T)
I (3) is the Inside FERC – Gas Market Report first-of-the-month posting for Prices of Spot Gas Delivered to Pipeline for Dominion Transmission Inc. – Appalachia.

TAAGCCBL represents Company's Total Annual Actual Gas Commodity Costs for Base Load deliveries of natural gas purchased for system supply and is equal to the total monthly actual gas commodity costs.

To the extent that TAAGCCBL exceeds TABGCCBL for the PBR period, then the GAIFBL Shared Expenses shall be computed as follows:

GAIFBL Shared Expenses = TAAGCCBL - TABGCCBL

To the extent that TAAGCCBL is less than TABGCCBL for the PBR period, then the GAIFBL Shared Savings shall be computed as follows:

GAIFBL Shared Savings = TABGCCBL - TAAGCCBL

ISSUED: July 29, 2005 **EFFECTIVE:** April 1, 2006

ISSUED BY: Gary L. Smith Vice President – Marketing & Regulatory Affairs/Kentucky Division

PBR

Experimental Performance Based Rate Mechanism (Continued)

GAIFSL

The GAIFSL shall be calculated by comparing the Total Annual Benchmark Gas Commodity Costs for Swing Load (TABGCCSL) system supply natural gas purchases for swing load for the PBR period to the Total Annual Actual Gas Commodity Costs for Swing Load (TAAGCCSL) system supply natural gas purchases for during the same period to determine if any shared expenses or shared savings exist.

TABGCCSL represents the Total Annual Benchmark Gas Commodity Costs for Swing Load gas purchases and equals the monthly Benchmark Gas Commodity Costs of gas purchased for Swing Load system supply (BGCCSL).

BGCCSL represents Benchmark Gas Commodity Costs for Swing Load gas purchases and shall be calculated on a monthly basis and accumulated for the PBR period. BGCCSL shall be calculated as follows:

$$BGCCSL = Sum\ [(APVSLi - PEFDCQSL) \times SAISLi] + (PEFDCQSL \times DAISL)$$

Where:

APVSL is the Actual Purchased Volumes of natural gas for Swing Load system supply for the month. The APVSL shall include purchases necessary to cover retention volumes required by the pipeline as fuel.

"i" represents each supply area.

PEFDCQSL are the Purchases in Excess of Firm Daily Contract Quantities delivered to Atmos' city gate. Firm Daily Contract Quantities are the maximum daily contract quantities which Company can deliver to its city gate under its various firm transportation agreements and arrangements.

SAISL is the Supply Area Index factor for Swing Load to be established for each supply area in which Company has firm transportation entitlements used to transport its natural gas purchases and for which price postings are available. The five supply areas are TGT-SL (Texas Gas Transmission-Zone SL), TGT-1 (Texas Gas Transmission-Zone 1), TGPL-0 (Tennessee Gas Pipeline-Zone 0), and TGPL-1 (Tennessee Gas Pipeline-Zone 1), and TGC-ELA (Trunkline Gas Company-ELA).

PBR

Experimental Performance Based Rate Mechanism (Continued)

The monthly SAISL for TGT-SL, TGT-1, TGPL-0, TGPL-1, and TGC-ELA shall be calculated using the following formula:

$$SAISLi = I(i)$$

Where:

"I" represents each index reflective of both supply area prices and price changes throughout the month in these various supply areas.

"i" represents each supply area.

The index for each supply zone is as follows:

SAISL (TGT-SL)

I (1) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South Texas Gas Zone SL averaged for the month.

SAISL (TGT-1)

I (2) is the average of the daily high and low Gas Daily postings for East Texas – North Louisiana Area, Texas Gas Zone 1 averaged for the month.

SAISL (TGPL-0)

I (3) is the average of the daily high and low Gas Daily postings for South – Corpus Christi, Tennessee, Zone 0. (T)

SAISL (TGPL-1)

I (4) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South – 500 leg and – 800 leg average for the month.

ATMOS ENERGY CORPORATION

PBR

Experimental Performance Based Rate Mechanism (Continued)

SAISL (TGC-ELA)

I (5) is the average of the daily high and low Gas Daily postings for Louisiana-Onshore South, Trunkline ELA.

DAISL is the Delivery Area Index factor for Swing Load to be established for purchases made by Company when Company has fully utilized its pipeline quantity entitlements on a daily basis and which are for delivery to Company's city gate from Texas Gas Transmission's Zone 2, 3 or 4, Tennessee Gas Pipeline's Zone 2, or Trunkline Gas Company's Zone 1B.

The monthly DAISL for TGT-2, 3, 4, TGPL-2, and TGC-1B shall be calculated using the following:

DAISL = I(1)

DAISL (TGT-2, 3, & 4), (TGPL-2) and (TGC-1B)

I (1) is the average of the daily high and low Gas Daily postings the Daily Price Survey for Appalachia, Dominion – South Point. (T)

TAAGCCSL represents Company's Total Annual Actual Gas Commodity Costs for Swing Load deliveries to Company's city gate and is equal to the total monthly actual gas commodity costs.

To the extent that TAAGCCSL exceeds TABGCCSL for the PBR period, then the GAIFSL Shared Expenses shall be computed as follows:

GAIFSL Shared Expenses = TAAGCCSL - TABGCCSL

To the extent that TAAGCCSL is less than TABGCCSL for the PBR period, then the GAIFSL Shared Savings shall be computed as follows:

GAIFSL Shared Savings = TABGCCSL - TAAGCCSL

ISSUED: July 29, 2005 **EFFECTIVE:** April 1, 2006

ISSUED BY: Gary L. Smith Vice President – Marketing & Regulatory Affairs/Kentucky Division

PBR

Experimental Performance Based Rate Mechanism (Continued)

TIF

TIF = Transportation Index Factor. The Transportation Index Factor shall be calculated by comparing the Total Annual Benchmark Transportation Costs (TABTC) of natural gas transportation services during the PBR period to the Total Annual Actual Transportation Costs (TAATC) applicable to the same period to determine if any shared expenses or shared savings exist.

The Total Annual Benchmark Transportation Costs (TABTC) are calculated as follows:

TABTC = Annual Sum of Monthly BTC

Where:

BTC is the Benchmark Transportation Costs which include both pipeline demand and volumetric costs associated with natural gas pipeline transportation services. The BTC shall be accumulated for the PBR period and shall be calculated as follows:

BTC = Sum [BM (TGT) + BM (TGPL) + BM (TGC) + BM (PPL)]

Where:

BM (TGT) is the benchmark associated with Texas Gas Transmission Corporation.

BM (TGPL) is the benchmark associated with Tennessee Gas Pipeline Company.

BM (TGC) is the benchmark associated with Trunkline Gas Company.

BM (PPL) is the benchmark associated with a proxy pipeline. This benchmark, which will be determined at the time of purchase, will be used to benchmark purchases of transportation capacity from non-traditional sources.

The benchmark associated with each pipeline shall be calculated a follows:

BM (TGT) = (TPDR x DQ) + (TPCR x AV) + S&DB
BM (TGPL) = (TPDR x DQ) + (TPCR x AV) + S&DB
BM (TGC) = (TPDR x DQ) + (TPCR x AV) + S&DB
BM (PPL) = (TPDR x DQ) + (TPCR x AV) + S&DB

Where:

TPDR is the applicable Tariffed Pipeline Demand Rate.

PBR

Experimental Performance Based Rate Mechanism (Continued)

DQ is the Demand Quantities contracted for by the Company from the applicable transportation provider.

TPCR is the applicable Tariffed Pipeline Commodity Rate.

AV is the Actual Volumes delivered at Company's city gate by the applicable transportation provider for the month.

S&DB represents Surcharges, Direct Bills and other applicable amounts approved by the Federal Energy Regulatory Commission (FERC). Such amounts are limited to FERC approved charges such as surcharges, direct bills, cashouts, take-or-pay amounts, Gas Supply Realignment and other Order 636 transition costs.

The Total Annual Actual Transportation Costs (TAATC) paid by Company for the PBR period shall include both pipeline demand and volumetric costs associated with natural gas pipeline transportation services as well as all applicable FERC approved surcharges, direct bills included in S&DB, less actual capacity release credits. Such costs shall exclude labor related or other expenses typically classified as operating and maintenance expenses.

To the extent that TAATC exceeds TABTC for the PBR period, then the TIF Shared Expenses shall be computed as follows:

$$\text{TIF Shared Expenses} = \text{TAATC} - \text{TABTC}$$

To the extent that the TAATC is less than TABTC for the PBR period, then the TIF Shared Savings shall be computed as follows:

$$\text{TIF Shared Savings} = \text{TABTC} - \text{TAATC}$$

Should one of the Company's pipeline transporters file a rate change effective during any PBR period and bill such proposed rates subject to refund, the period over which the benchmark comparison is made for the relevant transportation costs will be extended for one or more 12 month periods, until the FERC has approved final settled rates, which will be used as the appropriate benchmark. Company will not share in any of the savings or expenses related to the affected pipeline until final settled rates are approved.

OSSIF

OSSIF = Off-System Sales Index Factor. The Off-System Sales Index Factor shall be equal to the Net Revenue from Off-System Sales (NR).

ATMOS ENERGY CORPORATION

PBR

Experimental Performance Based Rate Mechanism (Continued)

Net Revenue is calculated as follows:

$$NR = OSREV - OOPC$$

Where:

OSREV is the total revenue associated with off-system sales and storage service transactions.

OOPC is the out-of-pocket costs associated with off-system sales and storage service transactions and shall be determined as follows:

$$OOPC = OOPC(GC) + OOPC(TC) + OOPC(SC) + OOPC(UGSC) + \text{Other Costs}$$

Where:

OOPC (GC) is the Out-of-Pocket Gas Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm supply contracts, the OOPC (GC) shall be the incremental costs to purchase the gas available under Company's firm supply contracts. For off-system sales not using Company's firm supply contracts, the OOPC (GC) shall be the incremental costs to purchase the gas from other entities.

OOPC (TC) is the Out-of-Pocket Transportation Costs associated with off-system sales transactions. For off-system sales utilizing Company's firm transportation agreements, the OOPC (TC) shall be the incremental cost to use the transportation available under Company's firm supply contracts. For off-system sales not using Company's firm transportation agreements, the OOPC (TC) shall be the incremental costs to purchase the transportation form other entities.

OOPC (SC) is the Out-of-Pocket Storage Costs associated with off-system sales of storage. If this is gas in Company's own storage or gas stored with Tennessee Gas Pipeline it shall be priced at the average price of the gas in Company's storage during the month of sale. If this is gas from the storage component of Texas Gas's No-Notice Service, this gas shall be priced at the replacement costs.

OOPC (UGSC) is the Out-of-Pocket Underground Storage Costs associated with off-system sales of storage services. For the off-systems sales of storage services utilizing Company's on-system storage, the OOPC (UGSC) shall include incremental storage losses, odorization, and other fuel-related costs such as purification, dehydration, and compression. Such costs shall exclude labor-related expenses.

Other Costs represent all other incremental costs and include, but are not limited to, costs such as applicable sales taxes and excise fees. Such costs shall exclude labor-related or other expenses typically classified as operating and maintenance expenses.

PBR

Experimental Performance Based Rate Mechanism (Continued)

ACSP

ACSP = Applicable Company Sharing Percentage. The ACSP shall be determined based on the PTAGSC.

Where:

PTAGSC = Percentage of Total Actual Gas Supply Costs. The PTAGSC shall be the TPBRR stated as a Percentage of Total Actual Gas Supply Costs and shall be calculated as follows:

PTAGSC = TPBRR / TAGSC

Where:

TAGSC = Total Actual Gas Supply Costs. The TAGSC shall be calculated as follows:

TAGSC = TAAGCCBL + TAAGCCSL + TAATC

If the absolute value of the PTAGSC is less than or equal to 1.0%, then the ACSP of 30% shall be applied to TPBRR to determine CSPBR. If the absolute value of the PTAGSC is greater than 1.0%, then the ACSP of 30% shall be applied to the amount of TPBRR that is equal to 1.0% of TAGSC to determine a portion of CSPBR, and the ACSP of 50% shall be applied to the amount of TPBRR that is in excess of 1.0% of TAGSC to determine a portion of CSPBR. These two portions are added together to produce the total CSPBR. (T)

BA

BA = Balance Adjustment. The BA is used to reconcile the difference between the amount of revenues billed or credited through the CSPBR and previous application of the BA and revenues which should have been billed or credited, as follows:

1. For the CSPBR, the balance adjustment amount will be the difference between the amount billed in a 12 month period from the application of the CSPBR and the actual amount used to establish the CSPBR for the period.

2. For the BA, the balance adjustment amount will be the difference between the amount billed in a 12-month period from the application of the BA and the actual amount used to establish the BA for the period.

Review

Within 60 days after the end of the fourth year of the five-year extension, the Company will file an assessment and review of the PBR mechanism for the first four years of the extension period. In that report and assessment, the Company will make any recommended modifications to the PBR mechanism.

ATMOS energy

September 19, 2005

RECEIVED

SEP 21 2005

PUBLIC SERVICE COMMISSION

Honorable Beth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
P.O. Box 615
Frankfort, Kentucky 40602-0615

Subject: First Data Request of Commission Staff
Performance-Based Ratemaking Mechanism (PBR)
Case 2005-00321

Dear Ms. O'Donnell:

Enclosed herein is the filing by Atmos Energy Corporation, of its First Data request of the Commission Staff, dated September 7, 2005 in Case Number 2005-00321. This filing includes the original and ten (10) copies.

Please direct all inquiries regarding the enclosed filing to me at the address below, or you may call me at (270) 685-8024.

Sincerely,

Gary L. Smith

Gary L. Smith
V.P. Marketing and Regulatory Affairs

Enclosures

2401 New Hartford Road, Owensboro, Kentucky 42303-1312
P 270-685-8000 F 270-685-8052 atmosenergy.com

RECEIVED

SEP 21 2005

PUBLIC SERVICE
COMMISSION

ATMOS energy

MODIFICATIONS OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE-BASED RATEMAKING MECHANISM (PBR)

CASE NO. 2005-00321

SEPTEMBER 7, 2005

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

MODIFICATIONS OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE-BASED RATEMAKING MECHANISM (PBR)	) CASE NO. 2005-00321

FIRST DATA REQUEST OF COMMISSION STAFF TO ATMOS ENERGY CORPORATION

Atmos Energy Corporation ("Atmos"), pursuant to 807 KAR 5:001, is requested to file with the Commission the original and ten copies of the following information, with a copy to all parties of record. The information requested herein is due no later than September 22, 2005. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the person who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure that it is legible. Where information herein has been previously provided, in the format requested herein, reference may be made to the specific location of said information in responding to this information request.

1. Refer to page 2 of Atmos's petition and Exhibit B, the proposed tariff. Atmos has requested that the Commission extend the current Performance-Based Ratemaking mechanism ("PBR") for two months.

a. The proposed tariff in Exhibit B, which has an effective date of April 1, 2006, appears to incorporate the changes proposed in the application. Clarify whether Atmos intends that the proposed modifications to the PBR be effective April 1, 2006, or whether the request to extend the current PBR to June 1, 2006 applies to the PBR mechanism as it currently exists.

b. Atmos requested that the current PBR be extended to June 1, 2006 in order to coincide with the expiration of its current asset management agreement. Describe how far along in the process Atmos is in developing a request for proposals ("RFP") for a new asset management agreement.

c. Atmos's existing asset management agreement has a term which expires June 1, 2006. Assuming it pursues a new asset management agreement, when does Atmos expect to seek Commission approval of such an agreement?

d. Explain whether it is Atmos's intent to issue an RFP for a new asset management agreement while this case is pending or if it intends to wait and issue such an RFP after this case has been decided.

2. Refer to page 10 of Atmos's report on its PBR for the period April 2002 – March 2005 ("PBR report"). Atmos proposes to incorporate a new component, the Gas Acquisition Index Factor for Asset Management ("GAIFAM").

a. Provide an example of a supplier discount that the GAIFAM would include.

b. Explain how this type of discount is currently incorporated into Atmos's rates.

3. Refer to page 11 of the PBR report where Atmos proposes to decrease the Percentage of Total Actual Gas Supply Costs ("PTAGSC") threshold from 2 percent to 1 percent.

a. Explain in detail why the level of NYMEX settle prices for natural gas should impact the threshold percentage.

b. Provide the NYMEX settle prices for "the most recent twelve months" and for calendar year 2002, both of which are referenced in Atmos's discussion for why the PTAGSC threshold should be lowered.

4. Did Atmos consider requesting that the PBR be made permanent as part of its filing? Explain the response in detail.

Beth O'Donnell
Executive Director
Public Service Commission
P. O. Box 615
Frankfort, KY 40602

DATED September 7, 2005

cc: All Parties

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

FIRST DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 1 a

QUESTION: Refer to page 2 of Atmos' petition and Exhibit B, the proposed tariff. Atmos has requested that the Commission extend the current Performance-Based Ratemaking mechanism ("PBR") for two months.

a. The proposed tariff in Exhibit B, which has an effective date of April 1, 2006, appears to incorporate the changes proposed in the application. Clarify whether Atmos intends that the proposed modifications to the PBR be effective April 1, 2006, or whether the request to extend the current PBR to June 1, 2006 applies to the PBR mechanism as it currently exists.

RESPONSE:

a. The Company dated the proposed tariff sheets April 1, 2006 since the current tariff expires on March 31, 2006. Also, in the event the Commission did not approve the requested extension of the current tariff, the Company wanted to implement the new program at the earliest opportunity. The Company would prefer to extend the current PBR mechanism an additional two months to align the PBR tariff with the expiration of the Company's current Natural Gas Sales, Transportation and Storage Agreement. If the two month extension is granted, the Company would file the revised tariff reflecting that the existing rider would expire on May 31, 2006. The dates on the proposed tariff, the final terms of which will be set in this Case, would be revised to reflect a June 1, 2006 effective date.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

FIRST DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 1 b

QUESTION: Refer to page 2 of Atmos' petition and Exhibit B, the proposed tariff. Atmos has requested that the Commission extend the current Performance-Based Ratemaking mechanism ("PBR") for two months.

b. Atmos requested that the current PBR be extended to June 1, 2006 in order to coincide with the expiration of its current asset management agreement. Describe how far along in the process Atmos is in developing a request for proposals ("RFP") for a new asset management agreement.

RESPONSE:

b. The Company, as stated in its final report on the existing PBR mechanism, has significantly refined its RFP processes, consistent with the Commission's Order in Case No. 2002-00245 and guidance in the recent gas procurement audit conducted by Liberty Consulting. For example, more detailed information on system throughput, daily operation of on-system storage facilities, and operation of pipeline storage facilities will be included in the upcoming RFP for gas supply and supply management services. Also, all supplemental information requested by any bidder will be provided to all prospective bidders.

The Company is in the early stages of developing the RFP for the supply agreement proposed to begin June 1, 2006. The Company intends to finalize the preparation of the RFP upon receipt of the final Order in this Case, to incorporate specific terms and conditions set for the future PBR tariff.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

FIRST DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 1 c

QUESTION: Refer to page 2 of Atmos' petition and Exhibit B, the proposed tariff. Atmos has requested that the Commission extend the current Performance-Based Ratemaking mechanism ("PBR") for two months.

c. Atmos' existing asset management agreement has a term which expires June 1, 2006. Assuming it pursues a new asset management agreement, when does Atmos expect to seek Commission approval of such an agreement?

RESPONSE:

c. Once a winning bidder has been selected, the Company would file any and all necessary documentation with the commission to seek any required review or approval of the new agreement.

Depending on the timing of the Order in this case, the Company hopes to issue the RFP by December 1, 2005. In this preliminary schedule, the selection of the successful bidder would take place by February 1, 2006 and the company would hope to have any required review and approval of the new agreement completed prior to the June 1, 2006 initiation of the supply agreement. Even if the preliminary schedule slips, and the successful bidder is not selected by March 1, 2006, three months would be available for any required review by the Commission.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

FIRST DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 1 d

QUESTION: Refer to page 2 of Atmos' petition and Exhibit B, the proposed tariff. Atmos has requested that the Commission extend the current Performance-Based Ratemaking mechanism ("PBR") for two months.

d. Explain whether it is Atmos' intent to issue an RFP for a new asset management agreement while this case is pending or if it intends to wait and issue such an RFP after this case has been decided.

RESPONSE:

d. The Company intends to finalize the preparation of the RFP upon receipt of the final Order in this Case, to incorporate specific terms and conditions set for the future PBR tariff. For additional information, please refer to DR 1(b) and DR 1(c) of this Staff Data Request.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

FIRST DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 2 a

QUESTION: Refer to page 10 of Atmos' report on its PBR for the period of April 2002 – March 2005 ("PBR Report"). Atmos proposes to incorporate a new component, the Gas Acquisition Index Factor for Asset Management ("GAIFAM").

a. Provide an example of a supplier discount that the GAIFAM would include.

RESPONSE:

a. The Company proposed the GAIFAM in order to provide greater flexibility in the structure of bids by prospective suppliers. An example would be a fixed annual discount amount instead of, or in combination with, an index-based volumetric discount.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

FIRST DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 2 b

QUESTION: Refer to page 10 of Atmos' report on its PBR for the period of April 2002 – March 2005 ("PBR Report"). Atmos proposes to incorporate a new component, the Gas Acquisition Index Factor for Asset Management ("GAIFAM").

b. Explain how this type of discount is currently incorporated into Atmos' rates.

RESPONSE:

b. Currently, the tariff rider does not specifically address a fixed discount structure (not tied to volumetric measures) into the savings calculations. The Company proposes this new factor to accommodate, and offer, the option to prospective suppliers to express their supply discount in alternative terms. In other words, a prospective supplier could propose to provide asset management services at a fixed annual discount amount, not tied to volumetric requirements and provide the volumetric supply with no discount to the established benchmarks. Incorporating a fixed discount component of the bid would not be a requirement for prospective suppliers.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATE: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 3 a

QUESTION: Refer to page 11 of the PBR report where Atmos proposes to decrease the Percentage of Total Actual Gas Supply Costs ("PTAGSC") threshold from 2 percent to 1 percent.

a. Explain in detail why the level of NYMEX settle prices for natural gas should impact the threshold percentage.

RESPONSE:

a. Market natural gas prices have risen sharply since 2002, when Case No. 2001-00317 first established the 2% threshold. The Company references the NYMEX settlement prices as an indicator of the magnitude of the increase. As referenced in the response to DR Item 3(b) of this Data Request, the supply component has more than doubled from 2002 to the most recent 12-month period. Other gas cost indices, including those included in the composite benchmark in the PBR, would reflect a similar magnitude of increase over the past three years. NYMEX prices for forward periods are remarkably higher than the settlement prices for the past twelve months.

The vast majority of the Company's total gas supply cost is the cost of the commodity purchases. The PBR was designed to reward the Company for maximizing gas cost savings through innovative purchasing structures. In essence, the hurdle to clear, before the Company begins to share 50% of the savings realized, has become twice as high as was originally set. The Company, in this proposal, merely seeks to reset the hurdle to approximate the level of 2002, in recognition of the unavoidable higher market costs today.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATE: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 3 b

QUESTION: Refer to page 11 of the PBR report where Atmos proposes to decrease the Percentage of Total Actual Gas Supply Costs ("PTAGSC") threshold from 2 percent to 1 percent.

b. Provide the NYMEX settle prices for "the most recent twelve months" and for calendar year 2002, both of which are referenced in Atmos' discussion for why the PTAGSC threshold should be lowered.

RESPONSE:

b. Please refer to the attached Exhibit KPSC DR-1, Item 3(b).

SUBMITTED BY: Gary Smith

Atmos Energy Corporation
KY PBR
NYMEX Closing Price Comparison

	(a)	(b)	(c)	(d)	(e)	(f)
Line Number	Calendar Year 2002		Most Recent 12 Months		$ Increase	% Increase
1	Jan-02	$ 2.5550	Jan-05	$ 6.2130	$ 3.6580	143%
2	Feb-02	$ 2.0060	Feb-05	$ 6.2880	$ 4.2820	213%
3	Mar-02	$ 2.3880	Mar-05	$ 6.3040	$ 3.9160	164%
4	Apr-02	$ 3.4720	Apr-05	$ 7.3230	$ 3.8510	111%
5	May-02	$ 3.3190	May-05	$ 6.7480	$ 3.4290	103%
6	Jun-02	$ 3.4200	Jun-05	$ 6.1230	$ 2.7030	79%
7	Jul-02	$ 3.2780	Jul-05	$ 6.9760	$ 3.6980	113%
8	Aug-02	$ 2.9760	Aug-04	$ 6.0480	$ 3.0720	103%
9	Sep-02	$ 3.2880	Sep-04	$ 5.0820	$ 1.7940	55%
10	Oct-02	$ 3.6860	Oct-04	$ 5.7230	$ 2.0370	55%
11	Nov-02	$ 4.1260	Nov-04	$ 7.6260	$ 3.5000	85%
12	Dec-02	$ 4.1400	Dec-04	$ 7.9760	$ 3.8360	93%
13	Average	$ 3.2212	Average	$ 6.5358	$ 3.3147	103%

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATE: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 4

QUESTION: Did Atmos consider requesting that the PBR be made permanent as part of its filing? Explain the response in detail.

RESPONSE:

The Company did not consider requesting that the PBR be made permanent as part of this filing, but is open to that possibility. The Company implemented the original PBR tariff rider in 1998 (as a result of Case No. 1997-00513), modified that tariff in 2002 (Case No. 2001-00317), and is proposing to modify and extend the tariff rider in this Case. In each case, a Natural Gas Sales, Transportation and Storage Agreement has been entered into in conjunction with the tariff mechanism. Given this history, the Company proposed to extend the program for an additional five years. The envisioned RFP process will permit suppliers to bid with varying terms of up to five years. The Company believes it is important for the terms of the PBR mechanism and the terms of the supplier agreement be synchronized to the extent practical.

If the PBR is a permanent tariff, future tariff adjustments to be proposed, if any, could be requested prior to initiating future RFP's for new supplier agreements.

SUBMITTED BY: Gary Smith

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

SEP 2 1 2005

PUBLIC SERVICE COMMISSION

In the Matter of:

MODIFICATIONS OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT RATEMAKING MECHANISM	)))	CASE NO. 2005-00321

ATTORNEY GENERAL'S INITIAL REQUEST FOR INFORMATION

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits this Initial Request for Information to Atmos Energy Corporation ("Atmos") to be answered by the date specified in the Commission's Order of Procedure, and in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company, please state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Respectfully submitted,
GREGORY D. STUMBO
ATTORNEY GENERAL

Lawrence W. Cook

Lawrence W. Cook
Assistant Attorney General
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204
502 696-5453

Certificate of Service and Filing

Counsel certifies that an original and seven photocopies of the foregoing Attorney General's Initial Request For Information were filed with and served by hand delivery to Beth O'Donnell, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to:

Honorable David F. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OH 45202

Honorable John N. Hughes
124 West Todd Street
Frankfort, KY 40601

Douglas Walther
Senior Analyst - Rate Administration
Atmos Energy Corporation
P. O. Box 650205
Dallas, TX 75235-0205

Honorable Mark R. Hutchinson
Wilson, Hutchinson & Poteat
611 Frederica Street
Owensboro, KY 42301

William J. Senter
V.P. Rates & Regulatory Affairs
Atmos Energy Corporation
2401 New Hartford Road
Owensboro, KY 42303-1312

This 7th day of September, 2005.

Lawrence W. Cook

Assistant Attorney General

Attorney General's Initial Request for Information
to Atmos Energy Corporation
Case Number 2005-00321

1. Please state the purpose behind Atmos' proposal to add Gas Acquisition Index Factor for Asset Management ("GAIFAM") as a new component or benchmark to Atmos' PBR. In your response, please include:
   a) the added benefit the incentive would represent for the ratepayer;
   b) the added benefit the incentive would represent for the shareholder;
   c) why it would be appropriate to add this incentive to this PBR when it was not included in the last PBRs, which were also implemented through asset management contracts;
   d) against what objective benchmark, criteria or standard would the incentive, including its performance and/or any potential savings, be measured and evaluated?
   e) what level of improved performance must exist before rewards in the form of shared savings are to be granted.

2. In the Application, Atmos states that the Gas Acquisition Index Factor for Asset Management would "distinguish and clearly recognize any supplier discounts provided for asset management rights, if any that are fixed discounts not directly tied to per unit natural gas purchases." Please explain what this means, and include in your explanation the benefit to ratepayers expected to be gained from asset management discount amounts that are not tied to per unit natural gas purchases, as opposed to those that are tied to per unit natural gas purchases in a gas supply performance based rate.

3. By requesting a reduction in the cost sharing mechanism from the current 2% level to 1% based on gas price increases, is the Company saying that shareholder participation in incentive sharing should become easier to obtain as the cost of gas to the ratepayer increases?

   a) State exactly what has changed from the time of Atmos' last approval of its PBR until now with regard to the industry standard represented by the benchmark against which Atmos' performance is to be measured, other than simply stating that it has risen with the increase in the price of gas?

b) Please explain why ratepayers should pay the company for a reduced level of performance in addition to paying for the ever-increasing cost of gas, an increase over which the company admits it has no control.

4. In what way or ways does Atmos' proposed modification represent current trends in the LDC industry?

5. Does the existing cost sharing mechanism allow Atmos to pass 50% of increased gas costs to ratepayers whenever there is more than a 2% variance between cost and benchmarks? If so, why is this mechanism not adequate to protect Atmos in current market conditions?

6. For each year of the PBR established in Case No. 2001-317 in which the threshold for capacity release was removed, state the amount by which capacity release exceeded the threshold that was established in Case No. 97-513.

7. What, if any incentive was offered to the gas supplier in conjunction with capacity release (i.e., a 10% Commission) in the initial PBR set forth in Case No. 97-513, in which the sharing in capacity release revenues was conditioned upon first meeting a capacity release threshold?

8. In what ways, if any, will the incentive offered to the gas supplier under the current request for a PBR modification differ from that already in place under the existing PBR?

ATMOS ENERGY CORPORATION
OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 1

QUESTION:

Please state the purpose behind Atmos' proposal to add Gas Acquisition Index Factor for Asset Management ("GAIFAM") as a new component or benchmark to Atmos' PBR. In your response, please include:

a. the added benefit the incentive would represent for the ratepayer;
b. the added benefit the incentive would represent for the shareholder;
c. why it would be appropriate to add this incentive to this PBR when it was not included in the last PBRs, which were also implemented through asset management contracts;
d. against which objective benchmark, criteria or standard would the incentive, including its performance and/or and potential savings, be measured and evaluated;
e. what level of improved performance must exist before rewards in the form of shared savings are to be granted.

RESPONSE:

The Company proposed the GAIFAM component in order to provide greater flexibility in the structure of bids by prospective suppliers. Currently, the tariff rider does not specifically address a fixed discount structure (not tied to volumetric measures) into the savings calculations. The Company proposes this new factor to accommodate, and offer, the option to prospective suppliers to express their supply discount in alternative terms. In other words, a prospective supplier could propose to provide asset management services at a fixed annual discount amount, not tied to volumetric requirements and provide the volumetric supply with no discount to the established benchmarks. Incorporating a fixed discount component of the bid would not be a requirement for prospective suppliers.

a. Adding the GAIFAM, as stated above, merely affords greater flexibility in the structure of bids by prospective suppliers, allowing the bid to include a supply discount in a fixed component (not tied to volumetric measures). By adding this bid structure option, we hope that the flexibility results in more favorable supplier bids. An additional benefit to the customers will be the reliability of such a discount; that savings is not dependent on volumetric throughput. If warmer than normal weather occurs, the portion of discount offered on a fixed basis would not be reduced due to lower purchase volumes.

b. Same response as AG DR-1, Item 1 (a) above.

c. An allowance for a fixed, non-volumetric, discount component was not envisioned in prior PBR programs.

d. The GAIFAM represents a fixed, non-volumetric, component of the supplier discount versus the established supply indices which comprise the benchmark. For example, a prospective supplier could propose to provide asset management services at a fixed annual discount amount, not tied to volumetric requirements, and provide the volumetric supply with no discount to the established benchmarks. In this case, the fixed annual discount would equal the savings rolling up through the Gas Acquisition Index Factor ("GAIF"). The Base Load savings ("GAIFBL") would equal zero, the Swing Load savings ("GAIFSL") would equal zero and the asset management ("GAIFAM") would equal the fixed supply discount component.

   The inclusion of this bid structure option merely affords more flexibility by prospective suppliers in the RFP process; hopefully to the benefit of customers and the Company.

e. As stated above, in AG DR-1, Item 1(d), the GAIFAM is purely an option for prospective suppliers to incorporate a fixed, non-volumetric, discount component in their bid for the full-requirements supply agreement. Incorporating a fixed discount will not be a required feature of a bid. If the selected supplier bid includes a fixed discount feature, that component will combine with the GAIFBL and GAIFSL savings to determine the total savings through the Gas Acquisition Index Factor.

Submitted by: Gary Smith

ATMOS ENERGY CORPORATION
OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 2

QUESTION:

In the Application, Atmos states that the Gas Acquisition Index Factor for Asset Management would "distinguish and clearly recognize any supplier discounts provided for asset management rights, if any that are fixed discounts not directly tied to per unit natural gas purchases." Please explain what this means, and include in your explanation the benefit to ratepayers expected to be gained from asset management discount amounts that are not tied to per unit natural gas purchases, as opposed to those that are tied to per unit natural gas purchases in a gas supply performance based rate.

RESPONSE:

The Company proposed the GAIFAM component in order to provide greater flexibility in the structure of bids by prospective suppliers. Currently, the tariff rider does not specifically address a fixed discount structure (not tied to volumetric measures) into the savings calculations. The Company proposes this new factor to accommodate, and offer, the option to prospective suppliers to express their supply discount in alternative terms. In other words, a prospective supplier could propose to provide asset management services at a fixed annual discount amount, not tied to volumetric requirements and provide the volumetric supply with no discount to the established benchmarks. Incorporating a fixed discount component of the bid would not be a requirement for prospective suppliers.

By adding this option, we hope that the greater flexibility in the structure of bids by prospective supplier's flexibility results in more favorable supplier bids. An additional benefit to the customers will be the reliability of such a discount; that savings is not dependent on volumetric throughput. For example, if warmer than normal weather occurs, the portion of discount offered on a fixed basis would not be reduced due to lower purchase volumes.

For more information, please reference the response to AG DR-1, Item 1 of this data request.

Submitted by: Gary Smith

**ATMOS ENERGY CORPORATION
OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005**

DATA REQUEST NO. 3

QUESTION:

By requesting a reduction in the cost sharing mechanism from the current 2% level to 1% based on gas price increases, is the Company saying that shareholder participation in incentive sharing should become easier to obtain as the cost of gas to the ratepayer increases?

a. State exactly what has changed from the time of Atmos' last approval of its PBR until now with regard to the industry standard represented by the benchmark against which Atmos' performance is to be measured, other than simply stating that it has risen with the increase in the price of gas.

b. Please explain why ratepayers should pay the Company for a reduced level of performance in addition to paying for the ever-increasing cost of gas, an increase over which the Company admits it has no control.

RESPONSE:

No. Market natural gas prices have risen sharply since 2002, when Case No. 2001-00317 first established the 2% threshold. In fact, the supply component has more than doubled from 2002 to the most recent 12-month period and forward price projections are remarkably higher than the settlement prices for the past twelve months.

The vast majority of the Company's total gas supply cost is the cost of the commodity purchases. The PBR was designed to reward the Company for maximizing gas cost savings through innovative purchasing structures. In essence, the hurdle to clear, before the Company begins to share 50% of the savings realized, has become twice as high as was originally set. The Company, in this proposal, merely seeks to reset the hurdle to approximate the level of 2002, in recognition of the unavoidable higher market costs today.

a. As mentioned above, the hurdle to clear, before the Company begins to share 50% of the savings realized, has become twice as high as was first established in Case No. 2001-00317 (the previous PBR mechanism had no such threshold, with all savings shared at 50:50). In our past experience with supplier bids under the PBR mechanism, the bids have been expressed as a $/Mcf discount. Therefore, as the overall benchmark prices have increased substantially, the supplier discount, as a % of the indices has been diluted. The Company, in this proposal, merely seeks to reset the hurdle to approximate the level of 2002, in recognition of the unavoidable higher market costs today.

b. Unfortunately, the Company cannot control the commodity cost of gas. The Company attempts to extract the lowest possible costs whenever possible. The Company has a substantial amount of storage, hedges a portion of its requirements and has reduced ratepayer costs through extensive negotiations with pipeline suppliers. The Company does not view all of these efforts as a reduced level of performance. Instead, in our view, we are merely proposing to reset the hurdle for 50% sharing to approximate the level of 2002, recognizing the lower overall market costs of that era.

Submitted by: Gary Smith

ATMOS ENERGY CORPORATION
OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 4

QUESTION:

In what way or ways does Atmos' proposed modification represent current trends in the LDC industry?

RESPONSE:

The proposed modification to include the GAIFAM represents a current trend in bids received in at least three (3) other jurisdictions. Please refer to AG DR-1, Item 1 for further information regarding the modification to include this component.

Submitted by: Gary Smith

ATMOS ENERGY CORPORATION,

OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 5

QUESTION:

Does the existing cost sharing mechanism allow Atmos to pass 50% of increased gas costs to ratepayers whenever there is more than a 2% variance between cost and benchmarks? If so, why is this mechanism not adequate to protect Atmos in current market conditions?

RESPONSE:

Yes, the existing cost sharing mechanism does allow Atmos to share 50% of savings or costs that are greater than a 2% variance between actual costs and the established benchmarks. Case No. 2001-00317 first established a "banded" range of sharing of costs/savings. In that Case, the first 2% of costs/savings would be shared 30:70 between shareholders and customers respectively. For costs/savings in excess of the 2% band, the incremental sharing would be 50:50.

In the Company's view, we are merely proposing to reset the hurdle for 50% sharing to approximate the level of 2002, recognizing the lower overall market costs of that era.

Please refer to the response to AG DR-1, Item 3 for more information.

Submitted by: Gary Smith

ATMOS ENERGY CORPORATION
OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 6

QUESTION:

For each year of the PBR established in Case No. 2001-317 in which the threshold for capacity release was removed, state the amount by which capacity release exceeded the threshold that was established in Case No. 97-513.

RESPONSE:

Please refer to Exhibit A of the Company's report for the monthly capacity release activity from April 2002 through March 2005.

The Company did not maintain a computation of the capacity release threshold during the period, since Case No. 2001-00317 eliminated that provision. The threshold which had been prescribed in the initial pilot PBR, in Case No. 97-513, was not a static threshold. The threshold was recomputed each year, a cumbersome calculation based upon numerous variables. The formula was basically as follows, in accordance with the tariff resulting in Case 97-513:

$$CRT = (WMPP \times WMVR \times WWARP) + (SMPP \times SMVR \times SWARP)$$

Where:

CRT equals the Capacity Release Threshold

WMPP represents the Winter Market Penetration Percentage computed for the twelve months prior to the PBR period (prior year) and rounded to the nearest whole percentage as follows:

$$WMPP = \frac{AWMR}{WSMQE - WCGD}$$

Where:

AWMR is the Actual Winter Mainline Release volume for the prior year.

WSMQE is Company's total firm Winter Seasonal Quantity Entitlements for the prior year under its firm transportation contracts with each of its pipeline transporters, adjusted as applicable under the appropriate transporter's FERC Approved Tariff.

WCGD is the Winter City Gate Deliveries under Company's Firm Transportation Agreements for the prior year.

WMVR is Winter Mainline Volumes Releasable under design conditions for the PBR period.

WWARP is the Winter Weighted Average Capacity Release Price based on information derived from Winter capacity release transactions (for mainline releases to the applicable pipeline zone of delivery in which Company is located) on each of Company's pipeline transporters for the concurrent PBR period.

SMPP represents the Summer Market Penetration Percentage computed for the twelve months prior to the PBR period (prior year) and rounded to the nearest whole percentage as follows:

$$SMPP = \frac{ASMR}{SSMQE - SCGD}$$

Where:

ASMR is the Actual Summer Mainline Release volume for the prior year.

SSMQE is Company's total firm Summer Seasonal Quantity Entitlements for the prior year under its firm transportation contracts with each of its pipeline transporters, adjusted as applicable under the appropriate transporter's FERC Approved Tariff.

SCGD is the Summer City Gate Deliveries under Company's Firm Transportation Agreements for the prior year.

SMVR is Summer Mainline Volumes Releasable under design conditions for the PBR period.

SWARP is the Summer Weighted Average Capacity Release Price based on information derived from Summer capacity release transactions (for mainline releases to the applicable pipeline zone of delivery in which Company is located) on each of Company's pipeline transporters for the concurrent PBR period.

Submitted by: Gary Smith

ATMOS ENERGY CORPORATION
OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 7

QUESTION:

What, if any, incentive was offered to the gas supplier in conjunction with capacity release (i.e. a 10% Commission) in the initial PBR set forth in Case No. 97-513, in which the sharing in capacity release revenues was conditioned upon first meeting a capacity release threshold?

RESPONSE:

In conjunction with the initial PBR, in Case No. 97-513, the Company entered into a supply agreement which established a commission-based sales program that paid a 10 percent commission for each dollar of capacity released

Submitted by: Gary Smith

ATMOS ENERGY CORPORATION
OFFICE OF THE ATTORNEY GENERAL
COMMONWEALTH OF KENTUCKY
CASE NO. 2005-00321
DATED: SEPTEMBER 7, 2005
DUE: SEPTEMBER 22, 2005

DATA REQUEST NO. 8

QUESTION:

In what ways, if any, will the incentive offered to the gas supplier under the current request for a PBR modification differ from that already in place under the existing PBR?

RESPONSE:

The Company has proposed no modifications in its current tariff proposal that alter the existing incentives to a future gas supplier.

Submitted by: Gary Smith

ATMOS energy

October 20, 2005

RECEIVED

OCT 21 2005

PUBLIC SERVICE COMMISSION

Honorable Beth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, Kentucky 40601

Subject: Second Data Request of Commission Staff to Atmos Energy
Case No. 2005-00321 – PBR

Dear Ms. O'Donnell:

Enclosed herein is the filing by Atmos Energy Corporation, to the Attorney General's Supplemental Data Request for information on the Performance Based Ratemaking Mechanism (PBR) dated October 7, 2005 in Case Number 2005-00321.

Please direct all inquiries regarding the enclosed filing to me at the address below, or you may call me at (270) 685-8024.

Sincerely,

Gary L. Smith

Gary L. Smith
V.P. Marketing and Regulatory Affairs

Enclosures

2401 New Hartford Road, Owensboro, Kentucky 42303-1312
P 270-685-8000 F 270-685-8052 atmosenergy.com

ATMOS energy

MODIFICATIONS OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE-BASED RATEMAKING MECHANISM (PBR)

CASE NO. 2005-00321

<u>SECOND DATA REQUEST OF COMMISSION STAFF TO ATMOS ENERGY CORPORATION</u>

OCTOBER 21, 2005

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

MODIFICATIONS OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE-BASED RATEMAKING MECHANISM (PBR)	) CASE NO. 2005-00321

<u>SECOND DATA REQUEST OF COMMISSION STAFF TO ATMOS ENERGY CORPORATION</u>

Atmos Energy Corporation ("Atmos"), pursuant to 807 KAR 5:001, is requested to file with the Commission the original and 10 copies of the following information, with a copy to all parties of record. The information requested herein is due no later than October 21, 2005. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the person who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure that it is legible. Where information herein has been previously provided, in the format requested herein, reference may be made to the specific location of said information in responding to this information request.

1. Refer to the response to Item 1(c) of the Commission Staff's September 7, 2005 information request.

a. The response states that "Depending on the timing of the Order in this case, the Company hopes to issue the RFP by December 1, 2005." How far in advance of December 1, 2005 does Atmos believe an Order is needed to enable it to issue its RFP by that date? Explain the response.

b. Is there any contingency arrangement in place that would permit the existing asset management agreement to be extended beyond June 1, 2006, if circumstances prevent Atmos from being able to meet the timeline described in the response? Explain the response.

2. Refer to the response to Item 4 of the Attorney General's September 7, 2005 information request.

a. The response states that "The proposed modification to include the GAIFAM represents a current trend in bids received in at least three (3) other jurisdictions." Identify the 3 jurisdictions, the utilities which received the bids, and the dates of the bids.

b. If they are in the possession of an Atmos affiliate, provide copies of the bids. If the bids contain confidential information, provide the copies in redacted form.

Robert A. Amato for
Beth O'Donnell
Executive Director
Public Service Commission
P. O. Box 615
Frankfort, Kentucky 40602

DATED October 7, 2005

cc: All Parties

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 7, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 1

QUESTION: Refer to the response to Item 1(c) of the Commission Staff's September 7, 2005 information request.

a. The response states that "Depending on the timing of the Order in this case, the Company hopes to issue the RFP by December 1, 2005." How far in advance of December 1, 2005 does Atmos believe an Order is needed to enable it to issue its RFP by that date? Explain the response.

b. Is there any contingency arrangement in place that would permit the existing asset management agreement to be extended beyond June 1, 2006, if circumstances prevent Atmos from being able to meet the timeline described in the response? Explain the response.

RESPONSE:

a. The Company would prefer as much time as possible to prepare the RFP after receiving an Order, but the Company will be flexible and will work with Commission to issue a RFP in a timely fashion. The RFP can be prepared, in large part, prior to the final Order in this Case. As noted in our response to DR # 1 (b) of the Commission Staffs first data request, detailed information on system throughput, operational data for on-system storage and pipeline storage facilities, etc. will be included in the RFP package. This data can be compiled and assembled in advance of finalizing the RFP. The Company will finalize the preparation of the RFP upon receipt of the final Order in this Case, merely to incorporate specific terms and conditions set for the future PBR tariff. That final step would not take long. Most of the preparatory efforts can precede that final step.

Also of note, with reference to DR # 1 (c) of Commission Staffs first data request, if we are delayed in issuing the RFP until January 1,

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 7, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 1

RESPONSE:

2006, we could allow two months for the bid submittal and selection to conclude by March 1, 2006. Under this timeline, three months would still be available for any required review of the new asset management agreement by the Commission.

b. The Company does not presently have a contingency plan in place with our current asset manager. However, subsequent to our receipt of this question from Commission Staff, we have contacted our current asset manager, Atmos Energy Marketing, to explore the possibility of such an arrangement.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 7, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST OF COMMISSION STAFF
DATA REQUEST NO. 2

QUESTION: Refer to the response to Item 4 of the Attorney General's September 7, 2005 information request.

a. The response states that "The proposed modification to include the GAIFAM represents a current trend in bids received in at least three (3) other jurisdictions." Identify the three jurisdictions, the utilities which received the bids, and the dates of the bids.

b. If they are in the possession of an Atmos affiliate, provide copies of the bids. If the bids contain confidential information, provide the copies in redacted form.

RESPONSE:

a. The Company has received bids that included an asset management fee in Tennessee, Virginia and Georgia. The Company received the bid for Tennessee and Virginia on March 24, 2004. This bid was awarded for a five (5) year term that began on April 1, 2004. The Company received the bid for Georgia on May 24, 2004. This bid was for a one (1) year term (October 2004 through September 2005), but was not the winning bid.

   Atmos Energy is not aware of the experiences of other utilities in regard to this matter, since the terms of bids submitted are typically not a matter of public record.

b. Please see the attached EXHIBIT KPSC DR 2-2 b for the requested bids, which are provided in redacted form.

SUBMITTED BY: Gary Smith

EXHIBIT
PSC DR-2, Item 2(b)

May 24, 2004

CONFIDENTIAL

Mr. Mark Bergeron
Atmos Energy Corporation
1515 Poydras St., Suite 2180
New Orleans, La. 70112

Dear Mr. Bergeron:

Please find enclosed a proposal from in response to your April 23, 2004 Gas Supply Request For Proposal. I believe that you will find this proposal responsive to your requirements as well as a competitive offer to provide gas supply services to Atmos.

a wholly owned subsidiary of and is a premier gas supply and asset management company. We are focussed on physical natural gas delivery and optimization of transportation and storage. We deliver over 2 BCF per day and have under management over 40 BCF of firm storage and 900,000 Dt/day of firm transportation. Our core geographic area of expertise is in the Southeast U.S., primarily on the Southern Natural and Transco systems. We have developed a comprehensive group of end-use counterparties on these systems and are a market leader in providing liquidity to the Southeast natural gas market. We are also a very large aggregator of production both onshore and offshore Gulf of Mexico supported by a well regarded Producer Services group within Take us up on our offer – you will be thrilled with the results!

Please call me at with any questions that you may have about this proposal.

With regards,

RECEIVED
DATE 5/25/04

EXHIBIT
PSC DR-2, Item 2(b)

Respondent Information:

CONFIDENTIAL

Contact Person:

Vice-President Asset Management and Origination
Phone:
Fax:
Email:

Evidence of Supplier's Knowledge and Experience: core line of business is providing natural gas supply and asset management services to gas utilities, industrial users, municipal utilities, and power generators. Our physical delivery of natural gas exceeds 2 BCF/day and we manage over 40 BCF of firm storage and 900,000 Dt/day of firm transportation. We are one of the largest shippers on Transco and Sonat and have developed an excellent track record of success in managing assets for our customers. We are also an aggregator of production from a large and diverse group of producers, primarily in the Gulf Coast. Also, one of the largest purchases of natural gas from the and one of the largest purchasers of production in the These supply relationships are managed by a team of Producer Services personnel at who have grown this business to over 750,000 Dth/day with a portfolio of term structures. Combining strong portfolio of production under management with our expertise in supply, transportation, and storage asset management provides with a reliable and cost competitive offer.

Evidence of Supplier's Financial Viability: Fitch rates parent, , with such rating recently reaffirmed. shall provide a parental guaranty to Atmos Energy to support obligations under this transaction.

Business References: Please find in attached Exhibit A a small sample of customers who we provide natural gas services.

RECEIVED
DATE 5/25/04

EXHIBIT
PSC DR-2, Item 2(b)

PROPOSALS

Option A:* *Commodity only supply delivered into Atmos' specific receipt points identified below:

		Baseload	Swing
Transco:			
	Station 30	IF FOM Index flat	Gas Daily Midpoint flat
	Station 45	IF FOM Index plus	Gas Daily Midpoint flat
	Station 65	IF FOM Index plus	Gas Daily Midpoint flat
	Station 85	IF FOM Index plus,	Gas Daily Midpoint flat
Sonat:			
	Zone 0 Tier 1	IF FOM Index plus $	Gas Daily Midpoint flat

All intra-day supplies will be priced at a mutually agreeable price.

CONFIDENTIAL

Option B:* *Commodity Supply plus optimization

In order to effectuate assuming the role of providing deliveries to Atmos' citygates, Atmos shall release or designate as agent for its transportation and storage contracts. Atmos' rights shall be no different than if was not taking on this function. In other words, Atmos preserves 100% of the flexibility embedded in its transportation and storage contracts by making such nominations to and having provide a rebundled citygate service to Atmos. To compensate Atmos for the value embedded in supply and storage optimization, shall pay Atmos an annual payment of , which represents the fixed asset optimization payment that shall guarantee to Atmos. This fee shall be made in twelve equal monthly installments in conjunction with the normal invoicing cycle. The commodity price associated with this Option is the same as that outlined in Option A.

Option C:* *Same as Option A, with only transportation capacity released to

This alternative is similar to Option A, however, it also assumes that the firm transportation shall be released to and . t shall make a citygate delivery of longhaul supplies. Atmos shall retain control of all storage contracts. The commodity price to Atmos shall be the price listed in the table below, plus variable transportation and fuel costs associated with transporting the gas from the receipt point to Atmos' citygates.

		Baseload	Swing
Transco:			
	Station 30	IF FOM Index flat	Gas Daily Midpoint flat
	Station 45	IF FOM Index plus	Gas Daily Midpoint flat
	Station 65	IF FOM Index plus	Gas Daily Midpoint flat
	Station 85	IF FOM Index plus,	Gas Daily Midpoint flat
Sonat:			
	Zone 0 Tier 1	IF FOM Index plus	Gas Daily Midpoint flat

RECEIVED
DATE 5/25/04

EXHIBIT
PSC DR-2, Item 2(b)

March 24, 2004

CONFIDENTIAL

Pat Childers, Vice President
Rates & Regulatory Affairs
Atmos Energy Corporation
810 Crescent Centre Drive
Suite 600
Franklin, TN 37067

Re: Request for Proposal for the Atmos Energy Corporation ("Atmos") Service Areas in the State of Tennessee and the State of Virginia.

Dear Pat,

is pleased to propose the following Agreement covering "Services Provided to Atmos (Corp)" and "Assets Provided by Atmos (Corp) to Proposer" using the required format below:

1. Services Provided to Atmos : $
(Positive signifies payment to Atmos, negative signifies credit from Atmos)

2. Assets Provided by Atmos to Proposer: $
(Positive signifies payment to Atmos, negative signifies credit from Atmos)

Annual Net Deal Payment to or Credit From Atmos: $
(Sum of 1. and 2.)

Notes:

Fuel Provided in kind by Atmos Energy Corporation for the following:

Barnsley Storage/Egan Exchange – Texas Gas zone SL to Texas Gas zone 3
Dominion GSS/TGP/ETN Exchange – Tennessee Gas zone 1 to zone 3
Dominion GSS/Middle Tennessee Service Area/TETCO ELA Exchange – Texas Eastern Ela to M2

Thank you for your consideration.

Sincerely,

Sr. Vice President

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 1

QUESTION: What role does asset management play in gas supply apart from a performance based rate?

RESPONSE:

The asset management model has been utilized by Atmos Energy since inception of the Performance Based Rate mechanism in 1998. Under this model, the Company arranges to receive full requirements supply from a single entity who also manages the Company's assets from day to day.

The asset manager is afforded the opportunity to optimize the assets not needed by the utility from time to time and generate revenues from on-system and off-system utilization of the idle assets. As a result, the Company and its customers are able to glean savings by affording asset management rights to the full requirements supplier.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 2

QUESTION: How important is asset management to gas supply?

RESPONSE:

Refer also to the Company's response to DR # 1 of this AG supplemental data request.

Assignment of the management of all of Atmos Energy's Kentucky firm transportation and storage contracts to the "full-requirements" supplier has proven to be a beneficial contract feature. The objective of Atmos Energy's supply contract is to ensure reliability and extract the lowest cost bid possible from potential bidders through the enticement offered by the largest and most comprehensive contract possible. The Request For Proposal combines the Company's full firm gas commodity requirements with all of its upstream transportation and storage contracts. Hence, potential suppliers are assured of the opportunity to supply Atmos Energy's large, firm market for multiple years plus the additional opportunity to leverage the substantial transportation capacity and storage assets beyond the actual supply requirements of that firm market from time to time when operationally feasible. Despite the breadth and supplier flexibility inherent in a full-requirements contract, the Company also retains full operational control through mandatory compliance with a prescribed seasonal storage and operational plan, and non-performance penalties and remedies.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 3

QUESTION: Would Atmos agree that having an asset management fee that is not tied to volume decouples wholesale price paid from retail price?

RESPONSE:

No.

The Company created the asset management fee allowance to permit creative bid structure options for prospective bidders, allowing for a fixed discount component not expressed in per volume terms. The fixed discount component, or asset management fee, would still be tied to the obligation for full requirements supply volumes. The tariff formula, currently, is based upon an expectation of solely a "cents off" discount to the gas commodity market basket of indices. The Company has no preference as to whether a bidder submits an index-based bid or a bid that incorporates a fixed discount component. The new addition to the tariff formula merely provides an option for bidders, from which the Company will choose the best bid.

The value of the Company's assets to any prospective bidder are not likely directly tied to the volume changes which will occur from year to year, primarily due to weather variations. During years of colder than normal weather, the Company's volume requirements would increase and its utilization of assets such as interstate capacity and storage would be increased as well. Under these conditions, the idle assets available to the Supplier would be less available. This example shows the mismatch between a Supplier volumetric discount which becomes greater with higher volumes, while arguably lowering the availability of the assets they can leaverage.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 4

QUESTION: Please state why it is appropriate to disassociate the concept of volume at the wholesale level, when Atmos and all other LDC's charge by volume at the retail level.

a. What assurance is there that the actual cost Atmos pays for gas at the wholesale level, on a basis different than volume, would somehow be accurately translated to a volumetric basis on the retail level?
b. How does Atmos propose to attribute the amount of any discount achieved through gas supply management, which may not be measured on a volumetric basis, to the retail customer, who always pays on a volumetric basis?
c. If the asset management fee does not vary with volume, how will savings credit offset against volume? Will the offset be higher per mcf in low volume years and lower per mcf in high volume years?

RESPONSE:

The Company, in this proposal, does not believe it is disassociating the concept of volume at the wholesale level. We merely believe there could be enhanced value to prospective supply bidders by allowing a fixed component in their bid structure.

a. The cost of gas would flow through the PGA in the same manner that it flows today. The Company could require the asset management fee to be paid, or credited toward supply costs on a uniform monthly basis. The fixed discount would then be reflected in the process of projecting gas costs and applying the discount in the reconciliation of actual costs, at the time they are available. The tariff proposed in this Case would establish the process for considering such a discount in the computation of PBR recoveries.

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 4

RESPONSE:

b. If the Company was to award the supply agreement to a bidder that incorporated an asset management fee into their bid, the Company would reflect those savings in a manner similar to other gas costs that are not volumetric in nature, such as interstate demand charges. Please also refer to DR # 4(a) of this AG data request.

c. The benefit of an asset management fee is that the guaranteed payment (or discount) is not affected by weather-related volume changes of the market. This structure would ensure a constant level of savings. Yes, on a per unit basis, the savings would be higher in low volume years and lower in high volume years, but the burden would purely be on the agent to provide the fixed discount component regardless of the volumes delivered.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 5

QUESTION: Please state why Atmos' PBR should be made permanent when Atmos has just developed and plans to employ an entirely new benchmark concept, that of the GAIFAM. Would Atmos agree that it is more appropriate that Atmos' PBR continue on a pilot basis when it establishes the new measures of performance?

RESPONSE:

The Company has proposed a five (5) year extension of the PBR in its Application. In an earlier response to DR # 4 of the First Data Request of Commission Staff, the Company acknowledged it would be open to a permanent implementation of the PBR tariff.

The referenced GAIFAM was introduced purely to give prospective vendors more flexibility in their bids in response to our Request For Proposals. There is no certainty that the vendor awarded the supply contract will incorporate an asset management fee structure in their bid.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 6

QUESTION: Please state whether the GAIFAM is connected in any way to any industry practice or standard.

RESPONSE:

The Company is seeing more asset management fees incorporated into responses to Requests For Proposals. The Company is attempting to create flexibility in the proposals submitted by prospective suppliers by accommodating the GAIFAM; the Company is not requiring or favoring an asset management fee structure, however.

Please also refer to the Company's response to DR # 2 of the Supplement Data Request from Commission Staff.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 7

QUESTION: KRS 278.272 provides as follows:

Consideration of natural gas purchasing transaction in determining just and reasonable rates; limitation of authorized rate of return for natural gas operations.

"In determining just and reasonable rates, the commission shall investigate and review natural gas purchasing transactions of a utility, whose rates for retail sales of natural gas are regulated by the commission, from an affiliate. The commission shall limit the authorized rate of return of the utility for its natural gas operations to a level which, when considered with the level of profit or return the affiliate earns on natural gas transactions to such utility, is just and reasonable." [Emphasis added]

Please state what measures the Commission has taken to investigate and review Atmos' purchase of gas from its affiliate.

RESPONSE:

The Commission conducted a thorough review of gas procurement practices of Atmos Energy and the other four large gas utilities in Kentucky, utilizing an independent consultant, Liberty Consulting, in that effort. The report, published in November 2002, addressed specific findings and recommendations regarding Atmos Energy's gas supply planning, organization & controls, supply management, transportation programs, balancing, response to regulatory change and affiliate relations. Additionally, report chapters common to the five Kentucky LDC's addressed natural gas price issues, impacts of hedging, GCA mechanisms, forecasting and impacts of affiliate relationships.

Atmos Energy received a favorable review in that comprehensive audit. Atmos Energy received nine recommendations for process improvements, among which were improvements to our RFP process, which will be employed in the upcoming asset management RFP. In regard to their review of affiliate relations, Liberty concluded Atmos

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
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SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 7

RESPONSE:

Energy's transactions were appropriate and had no recommendations for improvements.

Atmos Energy has continued to work closely with the management audit staff implementing the recommended gas procurement audit improvements.

In addition, the Company must file and the Commission must approve each change in the Company's gas costs before they are passed on to customers. With regard to Atmos Energy's gas costs, the Company is typically the lowest or second lowest cost provider in the State.

SUBMITTED BY: Gary Smith

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 8

QUESTION: KRS 278.274 provides, in pertinent part, as follows:

Review of natural gas utility's purchasing practices in determining reasonableness of proposed rates; reduction of rates by commission

(1) In determining whether proposed natural gas utility rates are just and reasonable, the commission shall review the utility's gas purchasing practices. The commission may disallow any costs or rates which are deemed to result from imprudent purchasing practices on the part of the utility.
(2) When proposing new rates, the utility shall be required to prove that the proposal is just and reasonable in accordance with the requirements of this section.
(3) It shall be presumed that natural gas purchases from affiliated companies are not conducted at arm's length...

a. Please state how the Commission will be able to determine whether Atmos' purchase of gas will be fair, reasonable and prudent when the wholesaler grants a gas purchase price discount, and in exchange acquires the right to use Atmos' assets.
b. In the event Atmos' gas supplier is an affiliate, please state how the Commission will be able to determine Atmos' profit return based on its gas purchases from its affiliate.
c. Please state how the fact that a PBR is in place reveals that Atmos in engaging in prudent practices.

RESPONSE:

a. The PBR process is an established and proven model through which pudency review is streamlined due to the establishment of pre-determined gas cost benchmarks and the competitive bidding process employed in awarding the asset management contract. While a prudence review is not a part of this model, the Commission through its review and approval of the PBR, establishes a benchmark against which all purchases are measured. Thus, the

ATMOS ENERGY CORPORATION
KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2005-00321
DATED: OCTOBER 4, 2005
DUE: OCTOBER 21, 2005

SUPPLEMENTAL DATA REQUEST – OFFICE OF THE ATTORNEY GENERAL
DATA REQUEST NO. 8

RESPONSE:

benchmark, in effect, provides a surrogate for a prudence review. The benchmark makes it clear to everyone in advance what the specific standard for recovery of the costs will be. The current benchmark was established through a settlement to which the Attorney General's office was a signatory.

b. The Commission can, and will, determine Atmos Energy's "profit return" based on its gas purchases from an affiliate (the witness assumes "profit return" is intended to mean the same as "rate of return") in the same manner as it determines a fair and just rate of return in all general rate adjustment proceedings; by analyzing a vast amount of information concerning the utility and its operations and then applying well established rate making principals to arrive at a fair and just rate of return. The PBR mechanism at issue in the current proceeding has not, and will not, limit or in any way interfere with the Commission establishing just and reasonable rates for Atmos Energy and its customers.

c. Please refer to the Company's response to DR # 7 and DR # 8 (a) of this supplemental AG data request.

SUBMITTED BY: Gary Smith

The Law Offices of

WILSON, HUTCHINSON & POTEAT
611 Frederica Street
Owensboro, Kentucky 42301
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Facsimile (270) 926-9394

William L. Wilson, Jr. bill@whplawfirm.com
Mark R. Hutchinson randy@whplawfirm.com
T. Steven Poteat steve@whplawfirm.com

FEDERAL EXPRESS

January 6, 2006

RECEIVED
JAN 9 2006
PUBLIC SERVICE COMMISSION

Beth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

RE: Response of Atmos Energy Corporation to Comments of the Attorney General
Case No. 2005-00321

Dear Ms. O'Donnell:

I am enclosing herewith an original, plus eleven (11) copies of a Response of Atmos Energy Corporation to Comments of the Attorney General in case no. 2005-00321 for filing in your office. Please return one stamped file copy to me. Thanks.

Very truly yours,

Mark R. Hutchinson

MRH:bkk

Enclosures

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

JAN 9 2006

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

MODIFICATION OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE BASED RATEMAKING MECHANISM (PBR)	)	**CASE NO. 2005-00321**

RESPONSE OF ATMOS ENERGY CORPORATION TO COMMENTS OF THE ATTORNEY GENERAL

Comes now Atmos Energy Corporation ("Atmos" or the "Company") and submits comments in the above-referenced Case pursuant to the Order by the Kentucky Public Service Commission (the "Commission") entered in this matter on December 16, 2005. The Intervenor in this Case, the Attorney General of the Commonwealth of Kentucky (the "AG") submitted written comments on the Company's proposal on December 27, 2005, but did not request a hearing or informal conference.

The Company, in its Application filed on July 29, 2005, submitted a Report on the results of the current PBR mechanism for acceptance by the Commission, sought authorization for a two month interim extension of the current PBR (to June 1, 2006) to synchronize the tariff with the expiration of the Company's current gas supply contract, and sought an order approving the proposed PBR mechanism, including certain modifications for a period of five (5) years, commencing June 1, 2006. The PBR is designed to create a system of rewards and penalties that encourage the Company to acquire low cost supplies of natural gas. As indicated in the Report filed by the Company, the current PBR mechanism has proven to be very beneficial to both the Company's ratepayers and its shareholders. Total savings attributable to the PBR for the 3 year period from April 2002 through March 2005 are more than $9,000,000. Customers have realized gas cost savings of nearly $6,150,000 for that three-year period.

The Company has been fully responsive to data requests from the Commission and the AG in accordance with the procedural schedule established in this Case by Commission Order dated August 16, 2005. Additionally, at the request of the AG, the Company participated in an informal teleconference on this matter with the AG on November 22, 2005. Extensive background information was provided by the Company to the AG concerning the PBR and its historical performance during the conference.

The results of the current PBR have proven successful, and it is noteworthy that the AG's comments filed on December 27, 2005 are exclusively focused on certain modifications to the PBR proposed by the Company as opposed to objecting to the PBR mechanism itself. The AG's comments are directed to the proposal to adjust the 50:50 sharing threshold from 2% of total gas costs to 1% and the proposal to incorporate a fixed discount component option for potential suppliers bidding for the full-requirements supply contract with the Company. In the data requests and in the informal conference with the AG, Atmos advocated the merits of each of these proposed modifications.

Prior to the current PBR, all savings/costs attributable to the PBR mechanism were shared

50:50 between the Company and the customers. In the current PBR, savings/costs are shared 30:70 respectively between the Company and customers for savings/cost levels up to 2% of the total gas cost. Incremental savings/costs greater than the 2% threshold are split 50:50. Due to much higher gas costs today in comparison to the gas costs when the threshold was set four years ago, the 2% threshold is basically unattainable. Resetting the threshold to 1% merely establishes a realistic incentive for the Company to stretch its creative gas acquisition strategies to increase its share of benefits or avoid an increased share of costs.

Introducing the option for potential suppliers to include a fixed discount component to their full-requirements supply bid is intended to maximize the value of the bids and to lower the overall gas supply costs to the customer. As the Company has pointed out, this new feature is not a bid requirement, simply an option for bidders. If this feature is approved, and bids may be structured with this component, the Company will be able to assess the value of the GAIFAM in the RFP selection process. For example, assume two competing bids are received, one with a fixed discount versus one with the discount expressed on a volumetric basis, each with a 5-year term. The Company could analyze the probability of weather variances and other volume-affecting factors over the term to determine the value of the "per Mcf" bid, and then compare that value to the fixed annual discount proposal. Benefits or disadvantages to the competing bids will be quantifiable. The GAIFAM is merely introducing the option for an alternative bid structure; whether the allowance proves beneficial to efforts to lower gas costs will be evident before choosing a bid with such a structure.

Respectfully submitted this 6 day of January, 2006.

Mark R. Hutchinson
WILSON, HUTCHINSON & POTEAT
611 Frederica Street
Owensboro, Kentucky 42301
(270) 926-5011

Douglas Walther
Atmos Energy Corporation
P.O. Box 650250
Dallas, Texas 75265

Attorneys for Atmos Energy

CERTIFICATE OF SERVICE

I hereby certify that on the 6 day of January 2006, the foregoing document was sent by facsimile transmission, and the original, together with eleven (11) copies, were sent by overnight delivery to the Kentucky Public Service Commission, 211 Sower Boulevard, P.O. Box 615, Frankfort, Kentucky 40602, and a true copy thereof mailed by first class mail to the following named persons:

Lawrence W. Cook
Assistant Attorney General
Office of Rate Intervention
1024 Capitol Center Drive
Suite 200
Frankfort, Kentucky 40601

Mark R. Hutchinson

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

MODIFICATION OF ATMOS ENERGY CORPORATION'S GAS COST ADJUSTMENT TO INCORPORATE PERFORMANCE BASED RATEMAKING MECHANISM (PBR)	))))	CASE NO. 2005-00321

O R D E R

On July 29, 2005, Atmos Energy Corporation ("Atmos") requested approval (1) to extend is its current gas cost performance-based ratemaking mechanism ("PBR") by 2 months, through May 31, 2006 in order to synchronize the term of the PBR with its current asset management contract and (2) to implement a revised PBR for a period of 5 years effective June 1, 2006.[1] The Commission approved the current PBR mechanism in March 2002 for 4 years expiring in March 2006.[2] The program benchmarks the following components of Atmos's gas costs: (1) commodity costs; (2) transportation costs; (3) capacity release revenues; and (4) off-system sales revenues. Actual costs and revenues are compared against benchmarks to determine how Atmos performed in its gas procurement activities.

[1] Atmos also requested that its report on its current PBR be accepted by the Commission.

[2] Case No. 2001-00317, Modification to Western Kentucky Gas Company, a Division of Atmos Energy Corporation, Gas Cost Adjustment to Incorporate an Experimental Performance-Based Ratemaking Mechanism (PBR), Order dated March 25, 2002.

Variances between the actual costs/revenues and the benchmarks are shared between shareholders and ratepayers on a sliding scale consisting of two bands. The first band covers variances from the benchmark ranging from 0 to 2.0 percent and is shared 70:30 between ratepayers and shareholders in favor of the ratepayers. The second band covers variances greater than 2.0 percent and is shared 50:50. Since the 1998 inception of its PBR, through March 2005, Atmos realized total savings of nearly $19,600,000, with the majority of this amount going to its customers.[3]

Atmos responded to two rounds of data requests from Commission Staff and the Attorney General ("AG"), the only intervenor in this proceeding. The parties chose to file written comments in lieu of a public hearing. All comments have been filed and the case stands submitted for decision.

ISSUES

Atmos proposes to modify the current PBR mechanism by adjusting the sharing mechanism so that the 70:30 sharing in favor of customers covers variances from the benchmark ranging from 0 to 1.0 percent rather than the current range of 0 to 2.0 percent. It also proposes, within the computation of the existing Gas Acquisition Index Factor ("GAIF"), to add a new component, the Gas Acquisition Index Factor for Asset Management ("GAIFAM"). The GAIFAM would allow greater flexibility by prospective gas suppliers in structuring their bids in response to Atmos's upcoming Request for Proposals for a new asset manager. Atmos contends that increases in natural gas prices since 2002, when the current sharing mechanism was approved, have doubled

[3] Report on Performance-Based Ratemaking Report Period: April 2002-March 2005 at 10.

its hurdle for achieving the 50:50 sharing band. It claims that the GAIFAM will distinguish and recognize any supplier discounts provided for asset management rights which are fixed discounts not directly tied to per unit natural gas purchases.

The AG filed comments on December 27, 2005. He takes issue with a number of components of the PBR, namely the proposed change in the sharing mechanism, the implementation of the GAIFAM component, and the potential permanent approval of the PBR, which was discussed by Atmos in response to a Staff data request.

The AG contends that the proposed change in the sharing mechanism is not warranted because the result would allow Atmos to do less for greater reward at a time when gas prices are at all-time highs. The AG argues that Atmos should not be allowed to prosper at or above the level previously established, as if prices had not increased, while its customers are being directly affected by the high prices, which are expected to remain high for the foreseeable future.

The AG opposes the proposed GAIFAM, arguing that there is no benchmark against which to compare an asset management fee and that Atmos is merely making a one-time effort to find a new asset manager after its current asset management contract expires. The AG also contends that any asset management fee should be based on volumes rather than allowing a fee based on a fixed dollar amount. The AG contends that a fixed fee creates an inverse ratio that will result in a smaller credit per Mcf when volumes are higher and a larger per Mcf credit when volumes are smaller.

Finally, the AG objects to any permanent approval of the PBR. He argues that there is no competitive market; therefore, there is no rationale for a PBR. He claims that, if the GAIFAM is approved, it would be unwise to make an entirely new benchmark permanent given that there is no experience with that component of the PBR. The AG also repeats arguments from prior cases concerning the inability to prove, conclusively, that a PBR results in lower gas costs than would occur absent the PBR.

Atmos filed reply comments January 6, 2006. Therein, it pointed out that during the initial pilot phase of its PBR, from 1998 to 2002, all savings/costs were shared by customers and shareholders on a 50:50 basis compared to the current PBR in which the 50:50 sharing does not take place until it exceeds that 2.0 percent threshold. Atmos contends that the higher gas costs currently in effect make the 2.0 percent threshold virtually unattainable.

Atmos explained that the GAIFAM, which would allow bidders to include a fixed discount in their bids, is intended to maximize the value of the bids and lower overall gas costs to customers. The GAIFAM is merely introducing an option for an alternative bid structure. Atmos will be able to determine if it results in lower gas costs before selecting a bid with such a structure.

Although the AG addressed the issue of making the PBR permanent, Atmos did not address this issue in its reply comments. The Commission surmises that this is because making the PBR permanent was not part of Atmos's proposal contained in its July 29, 2005 application.

ANALYSIS

The AG argues that a PBR should only exist if customers are better off with it than without it. As has been noted in prior PBR reviews, it is impossible to reconstruct the purchasing decisions a utility with a PBR would have made absent its PBR. Without such a reconstruction, there is no way to determine, with exact precision, the savings or expenses realized by the PBR. Atmos has, however, structured its supplier and asset management agreements to generate savings on its purchases, compared to the benchmarks established in its PBR mechanism.

The Commission is persuaded by Atmos's argument to include a fixed supplier discount in the form of the GAIFAM. In reviewing Atmos's supply bids in past reviews of its PBR and asset management agreement, the Commission has noted that not all bidders offer a gas supply discount. The Commission believes that expanding the type of discount included in the GAIF will allow Atmos more flexibility in its selection of its next asset manager. The Commission has already approved a fixed discount from an asset manager for The Union Light, Heat and Power Company ("ULH&P").[4] The AG raised no objection to ULH&P accepting a fixed discount and the Commission is not persuaded by the AG's arguments in this case against Atmos's proposed GAIFAM.

As for Atmos's proposal to lower the savings threshold for a 50:50 sharing from 2.0 to 1.0 percent, the Commission agrees with the AG's arguments. We are not persuaded that the current high gas prices justify lowering the threshold. We recognize that, at higher prices, Atmos's opportunities to reach the 50:50 sharing threshold are limited. However, given that Atmos has the ability to pass on and fully recover these high prices from its customers, with the result being that customers bear the full brunt of those prices, the Commission finds that Atmos's proposal, which could improve the standing of its shareholders, would only do so by worsening the standing of its customers. Accordingly, under current conditions, which reflect these high prices, we

[4] Case No. 2003-00024, Application of The Union Light, Heat and Power Company for Deviation from Requirements of KRS 278.2207(1)(b), Order dated July 1, 2003.

conclude that Atmos's proposal to lower the 50:50 sharing threshold from 2.0 to 1.0 percent must be rejected.

The Commission believes that Atmos's request to continue the current PBR for 2 months, to coincide with the expiration of its current asset management agreement, is reasonable as it corrects a timing oversight from the previous PBR review. While the AG again argues against a PBR, he argues specifically against making Atmos's PBR permanent.[5] The Commission concludes that it is reasonable to continue the PBR for 5 years, at which time the mechanism should again be reviewed. With its PBR continuing for a fairly lengthy period of time, the Commission finds that some period reporting should be required of Atmos on its activity under the PBR. At this juncture, we believe that annual reports will be sufficient for the Commission to adequately monitor the PBR and find that Atmos should file annual reports containing the same information as in the report it filed in this proceeding for the period ended March of 2005.

SUMMARY

The Commission, based on the evidence of record and being otherwise sufficiently advised, finds that:

1. The current PBR should be continued for 2 months through May 31, 2006.

2. Atmos's request to modify the sharing mechanism within its PBR on a prospective basis, beginning June 1, 2006, should be denied.

3. The GAIF should be modified prospectively, beginning June 1, 2006, to include the GAIFAM factor as proposed by Atmos.

[5] Atmos did not request that the PBR be approved permanently.

4. The PBR mechanism should be approved, subject to the modifications approved herein, and extended for an additional 5 years through May 31, 2011.

5. Atmos's report on the results of its current PBR should be accepted.

6. Atmos should file annual reports of its activity under the extended PBR including the same information as contained in the report filed in this proceeding. These reports should be filed by August 31 of each calendar year, commencing in 2007.

7. Within 90 days of the end of the fourth year of the 5-year extension, Atmos should file an evaluation report on the results of the PBR for the first 4 years of the extension period for the Commission's review for purposes of determining whether the PBR should be continued, modified, or terminated.

IT IS THEREFORE ORDERED that:

1. Atmos's current PBR is extended for 2 months through May 31, 2006.

2. Atmos's request to modify the sharing mechanism within its PBR on a prospective basis, beginning June 1, 2006, is denied.

3. Atmos's GAIF shall include its proposed GAIFAM factor beginning June 1, 2006.

4. Atmos's PBR mechanism shall be extended, as modified herein, for an additional 5 years through May 31, 2011.

5. Atmos's report on the results of the current PBR mechanism is accepted.

6. Atmos shall file annual reports of its activity under the extended PBR including the same information as contained in the report filed in this proceeding. These reports shall be filed by August 31 of each calendar year, commencing in 2007.

7. Within 90 days of the end of the fourth year of the 5-year extension, Atmos shall file an evaluation report on the results of the PBR for the first 4 years of the extension period, and the Commission shall review same for purposes of determining whether the PBR should be continued, modified, or terminated.

8. Atmos shall file its revised tariff sheets setting out the revisions to its PBR tariff, approved herein, within 20 days from the date of this Order.

Done at Frankfort, Kentucky, this 8th day of February, 2006.

By the Commission

ATTEST:

Executive Director

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 203
Witness: Gary Smith

Data Request:

Please provide the calculation of the Demand-Side Management Cost Recovery Mechanism for each year since the inception of this program. Provide all supporting documentation that has been supplied to the Commission.

Response:

The requested information is attached as AG DR1-203 ATT.

Atmos Energy Corporation
DSM Balancing Adjustment

	DSMRC Recoveries	DSMRC Costs	Under/(Over) DSMRC Balance	Residential Sales (Mcf)
Previous DBA Balancing Adjustment			$ 32,883.47	
Oct-05	$ 3,722.62	$ 11,183.31	$ 7,460.69	241,239
Nov-05	9,701.00	8,319.13	(1,381.87)	623,744
Dec-05	26,282.04	6,101.27	(20,180.77)	1,683,932
Jan-06	35,187.30	5,143.13	(30,044.17)	1,900,101
Feb-06	29,863.30	12,229.34	(17,633.96)	1,605,774
Mar-06	28,391.98	21,914.12	(6,477.86)	1,526,884
Apr-06	15,805.33	24,264.95	8,459.62	851,399
May-06	6,697.55	18,546.27	11,848.72	361,675
Jun-06	4,235.14	22,690.10	18,454.96	229,909
Jul-06	3,215.81	7,440.44	4,224.63	176,436
Aug-06	3,514.14	25,725.78	22,211.64	189,847
Sep-06	3,088.08	6,905.56	3,817.48	173,391
	$ 169,704.29	$ 170,463.40	$ 33,642.58	9,564,330

12 Month Average Interest Rate at Sep-06	4.8083%	$ 1,617.64
Total DBA Balancing Adjustment		$ 35,260.22
Annual Residential Sales (Mcf) - Weather Normalized		10,485,000
DSM Balancing Adjustment (DBA)		0.0034
DSM Cost Recovery Component (DSMRC):		
DSM Cost Recovery Current (DCRC): DSMRC Costs / Normalized Residential Sales		0.0163
DSM Balance Adjustment (DBA):		0.0034
DSMRC Residential Rate G-1		0.0197

Atmos Energy Corporation
DSM Balancing Adjustment

	DSMRC Recoveries	DSMRC Costs	Under/(Over) DSMRC Balance
Previous DBA Balancing Adjustment			$ 793.88
Oct-04	$ 3,925.12	$ 3,225.00	$ (700.12)
Nov-04	6,679.66	10,177.65	3,497.99
Dec-04	18,274.24	12,580.47	(5,693.77)
Jan-05	33,034.19	23,366.02	(9,668.17)
Feb-05	30,391.68	22,121.83	(8,269.85)
Mar-05	26,883.99	18,675.61	(8,208.38)
Apr-05	16,671.56	28,094.00	11,422.44
May-05	9,329.23	27,951.09	18,621.86
Jun-05	3,472.80	14,498.32	11,025.52
Jul-05	3,083.92	9,183.99	6,100.07
Aug-05	2,677.32	5,615.40	2,938.08
Sep-05	2,944.96	13,032.57	10,087.61
	$ 157,368.67	$ 188,521.95	$ 31,947.16
12 Month Average Interest Rate at Sep-05		2.9308%	$ 936.31
Total DBA Balancing Adjustment			$ 32,883.47
Annual Residential Sales (Mcf)			10,481,098
DSM Balancing Adjustment (DBA)			0.0031
DSM Cost Recovery Component (DSMRC):			
DSM Cost Recovery Current:			0.0155
DSM Balance Adjustment:			0.0031
DSMRC Residential Rate G-1			0.0186

Atmos Energy Corporation
DSM Balancing Adjustment

	DSMRC Recoveries	DSMRC Costs	Under/(Over) DSMRC Balance
Previous DBA Balancing Adjustment			$ 30,444.52
Oct-02	$ 4,623.22	$ 15,059.40	$ 10,436.18
Nov-02	$ 15,221.19	$ 7,361.15	$ (7,860.04)
Dec-02	$ 29,471.32	$ 9,993.98	$ (19,477.34)
Jan-03	$ 36,862.78	$ 13,738.97	$ (23,123.81)
Feb-03	$ 39,469.64	$ 7,996.11	$ (31,473.53)
Mar-03	$ 28,849.15	$ 10,787.16	$ (18,061.99)
Apr-03	$ 13,314.77	$ 22,161.59	$ 8,846.82
May-03	$ 5,449.82	$ 13,969.39	$ 8,519.57
Jun-03	$ 7,470.99	$ 6,547.15	$ (923.84)
Jul-03	$ 3,767.96	$ 10,246.75	$ 6,478.79
Aug-03	$ 4,048.06	$ 4,525.25	$ 477.19
Sep-03	$ 3,823.74	$ 8,577.02	$ 4,753.28
	$ 192,372.64	$ 130,963.92	$ (30,964.20)
1.2275% Interest, 12 Month Avg. at Sept. '03			$ (380.09)
Total DBA Balancing Adjustment			$ (31,344.29)
Annual Residential Sales (Mcf)			12,640,971
DSM Balancing Adjustment (DBA)			$ (0.0025)

Atmos Energy Corporation
DSM Balancing Adjustment

	DSMRC Recoveries	DSMRC Costs	Under/(Over) DSMRC Balance
Previous DBA Balancing Adjustment			$ (41,726.24)
Oct-01	$ 4,595.41	$ 9,103.17	$ 4,507.76
Nov-01	$ 11,104.75	$ 17,506.89	$ 6,402.14
Dec-01	$ 15,404.29	$ 26,983.09	$ 11,578.80
Jan-02	$ 33,820.93	$ 21,222.28	$ (12,598.65)
Feb-02	$ 26,913.04	$ 20,566.12	$ (6,346.92)
Mar-02	$ 25,994.96	$ 16,330.10	$ (9,664.86)
Apr-02	$ 16,833.00	$ 27,149.37	$ 10,316.37
May-02	$ 5,849.86	$ 18,256.86	$ 12,407.00
Jun-02	$ 5,817.66	$ 26,051.68	$ 20,234.02
Jul-02	$ 3,092.45	$ 18,516.82	$ 15,424.37
Aug-02	$ 2,914.29	$ 11,449.86	$ 8,535.57
Sep-02	$ 2,918.92	$ 13,743.29	$ 10,824.37
	$ 155,259.56	$ 226,879.53	$ 29,893.73
1.8425% Interest, 12 Month Avg. at Sept. '02			$ 550.79
Total DBA Balancing Adjustment			$ 30,444.52
Annual Residential Sales (Mcf)			10,775,706
DSM Balancing Adjustment (DBA)			$ 0.0028

Western Kentucky Gas Company,
A Division of Atmos Energy Corporation
DSM Balancing Adjustment

	DSMRC Recoveries	DSMRC Costs	Under/(Over) DSMRC Balance
Previous DBA Balancing Adjustment			$ (30,704.73)
Nov-00	$ 12,516.50	$14,839.30	$ 2,322.80
Dec-00	$ 35,129.36	$2,881.78	$ (32,247.58)
Jan-01	$ 40,005.62	$8,567.83	$ (31,437.79)
Feb-01	$ 28,282.94	$14,791.75	$ (13,491.19)
Mar-01	$ 20,529.53	$13,078.09	$ (7,451.44)
Apr-01	$ 16,263.94	$18,341.19	$ 2,077.25
May-01	$ 4,974.09	$19,408.59	$ 14,434.50
Jun-01	$ 3,539.67	$34,873.85	$ 31,334.18
Jul-01	$ 2,846.19	$14,386.72	$ 11,540.53
Aug-01	$ 2,590.25	$11,578.57	$ 8,988.32
Sep-01	$ 2,938.70	$7,736.57	$ 4,797.87
Oct-01	$ -		$ -
	$ 169,616.79	$ 160,484.24	$ (39,837.28)
4.7417% Interest, 12 Month Avg. at Sept. '01			$ (1,888.96)
Total DBA Balancing Adjustment			$ (41,726.24)
Annual Residential Sales (Mcf)			12,437,063
DSM Balancing Adjustment (DBA)			$ (0.0034)

Western Kentucky Gas Company,
A Division of Atmos Energy Corporation
DSM Balancing Adjustment

	DSMRC Recoveries	DSMRC Costs	Under/(Over) DSMRC Balance
Jan-00	$ 30,198.93	$ 20,035.50	$ (10,163.43)
Feb-00	$ 40,010.66	$ 5,811.72	$ (34,198.94)
Mar-00	$ 21,225.51	$ 8,496.71	$ (12,728.80)
Apr-00	$ 17,092.29	$ 18,799.65	$ 1,707.36
May-00	$ 8,492.68	$ 11,573.54	$ 3,080.86
Jun-00	$ 4,506.19	$ 7,396.73	$ 2,890.54
Jul-00	$ 3,680.09	$ 4,154.31	$ 474.22
Aug-00	$ 3,224.39	$ 12,973.03	$ 9,748.64
Sep-00	$ 3,842.02	$ 12,627.73	$ 8,785.71
Oct-00	$ 6,623.82	$ 8,125.69	$ 1,501.87
Nov-00	$ -	$ -	$ -
Dec-00	$ -	$ -	$ -
	$ 138,896.58	$ 109,994.61	$ (28,901.97)

6.2375% Interest, 12 Month Avg. at Oct. '00	$ (1,802.76)
Total DBA Balancing Adjustment	$ (30,704.73)
Annual Residential Sales (Mcf)	11,622,503
DSM Balancing Adjustment (DBA)	$ (0.0026)

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 204
Witness: Laurie Sherwood

Data Request:

Please provide copies of all presentations made to rating agencies and/or investment firms between January 1, 2005 and the present.

Response:

Please see response to AG DR1-209.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 205
Witness: Laurie Sherwood

Data Request:

Please provide copies of all prospectuses for any security issuances since January 1, 2005.

Response:

The only security issuance that Atmos Energy has undertaken since January 1, 2005 is the issuance of 5.5 million common shares in December 2006. The associated prospectus supplement is attached as AG DR1-205 ATT.

Filed Pursuant to Rule 424(b)(2)
Registration No. 333-139093

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Maximum Aggregate Offering Price	Amount of Registration Fee (2)(3)
Common stock (no par value per share)(1)	6,325,000 shares	$199,237,500	$21,319

(1) Includes, with respect to each share of common stock, Rights pursuant to the registrant's Rights Agreement, dated as of November 12, 1997, as amended, between the registrant and the Rights Agent named therein. Until any triggering event under the Rights Agreement occurs, the Rights trade with, and cannot be separated from, the common stock.

(2) Calculated in accordance with Rule 457(r) under the Securities Act.

(3) The fee has been satisfied by applying, pursuant to Rule 457(p) under the Securities Act, $21,319 of the previously paid filing fee of $278,740 with respect to the initial offering price of securities that were previously registered pursuant to the registrant's prior registration statement on Form S-3 (SEC File No. 333-118706), initially filed on August 31, 2004, and that have not been sold thereunder, of which $50,873 of the registration fee paid with respect to the prior registration statement remains unused. This "Calculation of Registration Fee" table shall be deemed to update the "Calculation of Registration Fee" table in the registrant's registration statement on Form S-3ASR (SEC File No. 333-139093).

PROSPECTUS SUPPLEMENT
(To Prospectus dated December 4, 2006)

5,500,000 Shares

ATMOS energy

Common Stock

This is an offering of 5,500,000 shares of the common stock of Atmos Energy Corporation.

Our common stock is listed on the New York Stock Exchange under the symbol "ATO." The last reported sales price of our common stock on December 7, 2006 was $32.07.

Investing in our common stock involves risks. See "Risk Factors" beginning on page 1 of the accompanying prospectus.

	Per Share	Total
Price to the public	$31.5000	$173,250,000
Underwriting discounts and commissions	$ 1.1025	$ 6,063,750
Proceeds to Atmos Energy Corporation (before expenses)	$30.3975	$167,186,250

We have granted to the underwriters the option to purchase up to 825,000 additional shares of common stock on the same terms and conditions set forth above if the underwriters sell more than 5,500,000 shares of common stock in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed on the adequacy or accuracy of this prospectus supplement. Any representation to the contrary is a criminal offense.

Lehman Brothers and Goldman, Sachs & Co., on behalf of the underwriters, expect to deliver the shares on or about December 13, 2006.

Joint Book-Running Managers

LEHMAN BROTHERS GOLDMAN, SACHS & CO.

BANC OF AMERICA SECURITIES LLC
JPMORGAN
MERRILL LYNCH & CO.
SUNTRUST ROBINSON HUMPHREY
WACHOVIA SECURITIES

December 7, 2006

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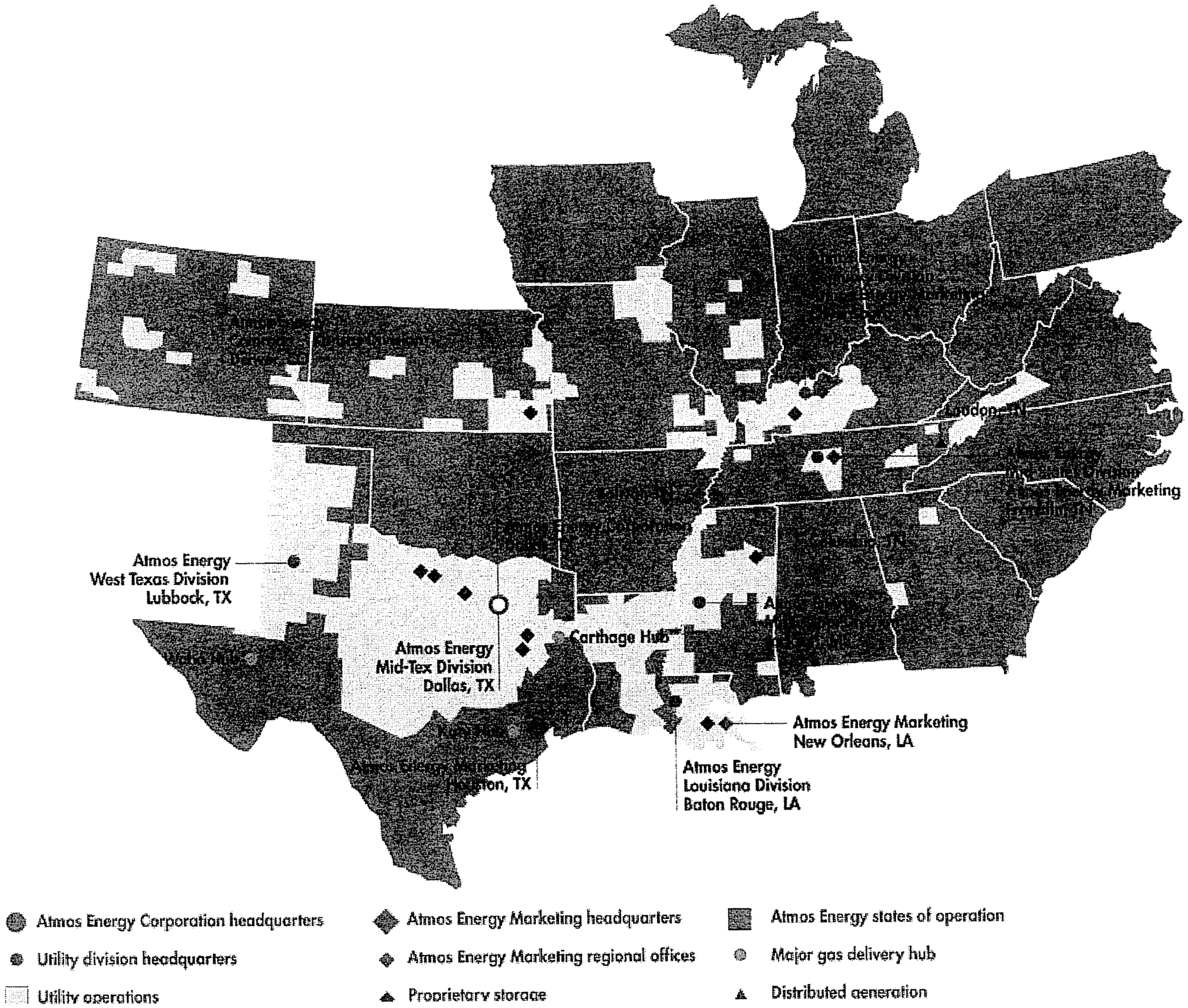

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PROSPECTUS

You should rely only on the information contained in this document or to which we have referred you. We have not authorized anyone to provide you with information that is different. This document may only be used where it is legal to sell these securities. The information in this document may only be accurate on the date of this document.

IMPORTANT NOTICE ABOUT INFORMATION IN THIS PROSPECTUS SUPPLEMENT AND THE ACCOMPANYING PROSPECTUS

This document is in two parts. The first part is this prospectus supplement, which describes the specific terms of this offering of the common stock and also adds to and updates information contained in the accompanying prospectus and the documents incorporated by reference in this prospectus supplement and the accompanying prospectus. The second part is the accompanying prospectus, dated December 4, 2006, which gives more general information, some of which does not apply to this offering. To the extent there is a conflict between the information contained in this prospectus supplement, the information contained in the accompanying prospectus or the information contained in any document incorporated by reference herein or therein, the information contained in the most recently dated document shall control.

You should rely only on the information contained in or incorporated by reference in this prospectus supplement and the accompanying prospectus. We have not, and the underwriters have not, authorized any other person to provide you with information that is different. If anyone provides you with different or inconsistent information, you should not rely on it. See "Incorporation by Reference" in this prospectus supplement and "Where You Can Find More Information" in the accompanying prospectus.

We are offering to sell, and seeking offers to buy, the common stock only in jurisdictions where offers and sales are permitted.

The information contained in or incorporated by reference in this document is accurate only as of the date of this prospectus supplement, regardless of the time of delivery of this prospectus supplement or of any sale of common stock.

INCORPORATION BY REFERENCE

The SEC allows us to "incorporate by reference" information in this prospectus supplement and the accompanying prospectus that we have filed with it. This means that we can disclose important information to you by referring you to another document filed separately with the SEC. The information incorporated by reference is considered to be part of this prospectus supplement and the accompanying prospectus, except for any information that is superseded by information that is included directly in this prospectus supplement or the accompanying prospectus.

We incorporate by reference in this prospectus supplement and the accompanying prospectus the documents listed below and any future filings we make with the SEC under sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 prior to the termination of this offering. These additional documents include periodic reports, such as annual reports on Form 10-K and quarterly reports on Form 10-Q and current reports on Form 8-K (other than information furnished under Items 2.02 and 7.01, which is deemed not to be incorporated by reference in this prospectus supplement or the accompanying prospectus), as well as proxy statements. You should review these filings as they may disclose a change in our business, prospects, financial condition or other affairs after the date of this prospectus supplement. The information that we file later with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act and before the termination of this offering will automatically update and supersede previous information included or incorporated by reference in this prospectus supplement and the accompanying prospectus.

This prospectus supplement and the accompanying prospectus incorporate by reference the documents listed below that we have filed with the SEC but have not been included or delivered with this document:

- Our annual report on Form 10-K for the year ended September 30, 2006; and
- Our current reports on Form 8-K filed with the SEC on October 20, 2006, November 13, 2006 and December 4, 2006.

These documents contain important information about us and our financial condition.

You may obtain a copy of any of these filings, or any of our future filings, from us without charge by requesting it in writing or by telephone at the following address or telephone number:

Atmos Energy Corporation
1800 Three Lincoln Centre
5430 LBJ Freeway
Dallas, Texas 75240
Attention: Susan Kappes Giles
(972) 934-9227

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Statements contained or incorporated by reference in this prospectus supplement that are not statements of historical fact are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933. Forward-looking statements are based on management's beliefs as well as assumptions made by, and information currently available to, management. Because such statements are based on expectations as to future results and are not statements of fact, actual results may differ materially from those stated. Important factors that could cause future results to differ include, but are not limited to:

- regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions;
- adverse weather conditions, such as warmer-than-normal weather in our utility service territories or colder-than-normal weather that could adversely affect our natural gas marketing activities;
- the concentration of our distribution, pipeline and storage operations in one state;
- impact of environmental regulations on our business;
- market risks beyond our control affecting our risk management activities, including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness;
- our ability to continue to access the capital markets;
- effects of inflation;
- effects of changes in the availability and prices of natural gas, including the volatility of natural gas prices;
- increased competition from other energy suppliers and alternative forms of energy;
- increased costs of providing pension and post-retirement health care benefits;
- the capital-intensive nature of our distribution business;
- the inherent hazards and risks involved in operating a distribution business;
- effects of natural disasters or terrorist activities; and
- other factors discussed in this prospectus and our other filings with the SEC.

All of these factors are difficult to predict and many 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. When used in 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. We undertake no obligation to update or revise our forward-looking statements, whether as a result of new information, future events or otherwise.

For further factors you should consider, please refer to the "Risk Factors" sections beginning on page 1 of the accompanying prospectus and Sections "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our annual report on Form 10-K for the year ended September 30, 2006. See "Incorporation by Reference."

The terms "we," "our," "us" and "Atmos" refer to Atmos Energy Corporation and its subsidiaries unless the context suggests otherwise. The term "you" refers to a prospective investor. The abbreviations "Mcf," "MMcf" and "Bcf" mean thousand cubic feet, million cubic feet and billion cubic feet, respectively. The abbreviation "MMBtu" means million British thermal units.

Except as otherwise indicated, all information in this prospectus supplement assumes that the underwriters have not exercised their option to purchase additional shares of common stock.

PROSPECTUS SUPPLEMENT SUMMARY

You should read the following summary in conjunction with the more detailed information contained elsewhere in this prospectus supplement, the accompanying prospectus and the documents incorporated by reference in this prospectus supplement and the accompanying prospectus.

Atmos Energy Corporation

Atmos Energy Corporation and its subsidiaries are engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. We are one of the country's largest natural-gas-only distributors based on number of customers and one of the largest intrastate pipeline operators in Texas based upon miles of pipe. As of September 30, 2006, we distributed natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our seven regulated utility divisions, which covered service areas in 12 states. 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. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to some of our utility divisions and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

Our overall strategy is to:

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

We have experienced over 20 consecutive years of increasing dividends and earnings growth after giving effect to our acquisitions. We have achieved this record of growth while operating our utility operations efficiently by managing our operating and maintenance expenses and leveraging our technology to achieve more efficient operations. In addition, we have focused on regulatory rate proceedings to increase revenue as our costs increase and to mitigate weather-related risks through weather-normalized rates. We have also strengthened our nonutility businesses by increasing gross profit margins, actively pursuing opportunities to increase the amount of storage available to us and expanding commercial opportunities in our pipeline and storage segment.

Over the last five years, we have primarily grown through two significant acquisitions, our acquisition in December 2002 of Mississippi Valley Gas Company (MVG) and our acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas). The TXU Gas acquisition doubled our number of utility customers, by adding approximately 1.5 million gas customers to our utility operations in Texas, including the Dallas-Fort Worth metropolitan area and the northern suburbs of Austin. The acquisition also added 6,162 miles of gas transmission and gathering lines and five underground storage reservoirs, all within Texas.

During the last two fiscal years, we have achieved the following:

Integration of TXU Gas. We completed the integration of the TXU Gas operations during fiscal 2005, incorporating the administrative functions of TXU Gas into our headquarters in Dallas and managing all meter reading, customer billing and call center functions internally.

Regulatory Activities. We pursued rate design changes and, as a result, we now have weather protection for over 90 percent of our residential and commercial customer meters beginning with the 2006-2007 winter heating season. During fiscal 2005, we obtained improved rate design in Mississippi, including improved weather normalization. During fiscal 2006, our Mid-Tex Division received a weather normalization adjustment as a part of a pending rate case and our Louisiana Division obtained a new rate design that will decouple our margins from all customer usage patterns. We were also permitted to implement new rates in our Louisiana Division in fiscal 2006, subject to possible refund, to cover customer losses in Hurricane Katrina-affected parishes and provide for increases in rate base and operating expenses.

Completed Growth Projects. We completed four new pipeline projects during fiscal 2006, the largest of which was a joint venture project to install a 45-mile 30-inch pipeline to serve the northern suburbs of the Dallas-Fort Worth metropolitan area. We believe that this pipeline will help us deliver gas to a growing consumer market while providing increased gas transmission capacity to serve the Texas intrastate wholesale gas market.

Recent Developments

Results for Fiscal 2006. In fiscal 2006, we reported net income of $147.7 million, or $1.82 per diluted share, compared to net income of $135.8 million, or $1.72 per diluted share, in fiscal 2005. The nine percent year-over-year increase in net income was primarily attributable to strong financial results in our natural gas marketing segment as it was able to capture higher margins in a volatile natural gas market and the inclusion of unrealized mark-to-market gains. Additionally, pipeline and storage net income increased 16 percent compared with the prior year. These results helped overcome the adverse effects on our utility segment of weather (adjusted for weather normalization) that was 13 percent warmer than normal, the adverse effect of Hurricane Katrina on our Louisiana Division and a non-cash charge to impair certain assets. Our utility operations contributed $53.0 million ($0.65 per diluted share) or 36 percent to fiscal 2006 results, compared with $81.1 million ($1.03 per diluted share) or 60 percent to fiscal 2005 results. Our nonutility operations comprised of our natural gas marketing, pipeline and storage and other nonutility segments, contributed $94.7 million ($1.17 per diluted share) or 64 percent to fiscal 2006 results, compared with $54.7 million ($0.69 per diluted share) or 40 percent to fiscal 2005 results. See "Summary Financial and Operating Data" on page S-4 and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our annual report on Form 10-K for the year ended September 30, 2006, for more information on our results for fiscal 2006 and comparisons to prior period results.

Straight Creek Project. In May 2006, we announced plans to expand our nonutility operations through the construction of a natural gas gathering system in Eastern Kentucky, which we refer to as the Straight Creek Project. We believe that our Straight Creek Project will relieve gas gathering and transportation constraints that have historically burdened natural gas producers in this area of Eastern Kentucky and should also improve delivery reliability to natural gas customers. As currently designed, the Straight Creek Project is expected to cost between $75.0 million and $80.0 million. Construction is expected to begin in the first half of fiscal 2007, with operations expected to begin in fiscal 2008. On October 6, 2006, we announced that the Federal Energy Regulatory Commission (FERC) issued a declaratory order finding that our Straight Creek Project, as currently designed, will be exempt from FERC jurisdiction.

Dividend Announcement. On November 7, 2006, we announced that our Board of Directors declared a quarterly dividend increase on our common stock of approximately 2 percent to $0.32 per share of common stock. The dividend will be paid on December 11, 2006, to shareholders of record on November 27, 2006. Individuals who purchase shares of our common stock in this offering will not be entitled to receive this dividend.

Five-Year Revolving Credit Agreement. We have negotiated a $600 million five-year revolving credit agreement with a syndicate of 15 lenders that backstops our commercial paper program. This agreement will replace and contain substantially the same terms as our existing $600 million three-year revolving credit agreement that we entered into in October 2005. We have received regulatory approval for this agreement and expect to enter into it in December 2006.

Other Developments

At our 2007 annual meeting of shareholders, scheduled for February 7, 2007, we will ask our shareholders to approve an amendment to our 1998 Long-Term Incentive Plan to increase the number of shares of our common stock reserved for issuance under the plan by 2,500,000 shares and to extend the term of the plan for an additional three years. We will also ask our shareholders to approve an extension to the term of our Annual Incentive Plan for Management by an additional five years. Holders of record of our common stock on December 11, 2006, the record date for the meeting, will be entitled to vote at the annual meeting. Therefore, the common stock that we issue in this offering will not be entitled to vote at the 2007 annual meeting.

Our address is 1800 Three Lincoln Centre, 5430 LBJ Freeway, Dallas, Texas 75240, and our telephone number is (972) 934-9227. Our internet Web site address is *www.atmosenergy.com.* Information on or connected to our internet Web site is not part of this prospectus supplement or the accompanying prospectus.

Summary Financial and Operating Data
(in thousands, except per share data)

The following table presents summary consolidated and segment financial and operating data of Atmos Energy Corporation for the periods and as of the dates indicated. We derived the summary financial data for the fiscal years ended September 30, 2006, 2005, 2004, 2003 and 2002 from our audited consolidated financial statements. The information is only a summary and does not provide all of the information contained in our financial statements. Therefore, you should read the information presented below in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included in our annual report on Form 10-K for the year ended September 30, 2006, which is incorporated by reference in this prospectus supplement and the accompanying prospectus. Over the periods presented below, we have primarily grown through two significant acquisitions, MVG in December 2002 and TXU Gas in October 2004. As a result, our consolidated financial and operating data presented below include results and data from operations of MVG and TXU Gas from the dates of the acquisitions; therefore, comparisons between periods may not be meaningful.

	Year Ended September 30,				
	2006[1]	2005[2]	2004[3]	2003[4]	2002
Consolidated Financial Data					
Operating revenues	$6,152,363	$4,961,873	$2,920,037	$2,799,916	$1,650,964
Gross profit	1,216,570	1,117,637	562,191	534,976	431,140
Operating expenses	833,954	768,982	368,496	347,136	275,809
Operating income	382,616	348,655	193,695	187,840	155,331
Interest charges	146,607	132,658	65,437	63,660	59,174
Miscellaneous income (expense)	881	2,021	9,507	2,191	(1,321)
Income tax expense	89,153	82,233	51,538	46,910	35,180
Cumulative effect of accounting change, net of income tax benefit	—	—	—	(7,773)	—
Net income	$ 147,737	$ 135,785	$ 86,227	$ 71,688	$ 59,656
Diluted net income per share before cumulative effect of accounting change, net of tax	$ 1.82	$ 1.72	$ 1.58	$ 1.71	$ 1.45
Diluted net income per share	$ 1.82	$ 1.72	$ 1.58	$ 1.54	$ 1.45
Cash dividends paid per share	$ 1.26	$ 1.24	$ 1.22	$ 1.20	$ 1.18
Cash flow from operating activities	$ 311,449	$ 386,944	$ 270,734	$ 49,451	$ 297,395
Capital expenditures	$ 425,324	$ 333,183	$ 190,285	$ 159,439	$ 132,252

	Year Ended September 30,				
	2006	2005[2]	2004	2003[4]	2002
Selected Operating Data					
Utility meters in service, end of year	3,181,199	3,157,840	1,679,136	1,672,798	1,389,341
Total utility throughput (MMcf)[5]	398,993	418,381	260,965	254,671	214,133
Natural gas marketing sales volumes (MMcf)[5]	336,516	273,201	265,090	294,785	273,692
Pipeline transportation volumes (MMcf)[5]	590,985	563,949	9,395	11,648	12,788

	As of September 30,				
	2006	2005	2004	2003	2002
Consolidated Balance Sheet Data					
Net property, plant and equipment[6]	$3,629,156	$3,374,367	$1,722,521	$1,624,394	$1,380,070
Working capital[6]	$ (1,616)	$ 151,675	$ 283,310	$ 16,248	$ (139,150)
Total assets[6]	$5,719,547	$5,653,527	$2,912,627	$2,625,495	$2,059,631
Debt					
Long-term debt[7]	$2,180,362	$2,183,104	$ 861,311	$ 862,500	$ 668,959
Short-term debt[7]	385,602	148,073	5,908	127,940	167,771
Total debt	$2,565,964	$2,331,177	$ 867,219	$ 990,440	$ 836,730
Shareholders' equity	$1,648,098	$1,602,422	$1,133,459	$ 857,517	$ 573,235

	Year Ended September 30,				
	2006	2005	2004	2003	2002[8]
Segment Operating Income					
Utility	$ 201,894	$ 236,365	$ 159,890	$ 161,134	$ 125,506
Natural gas marketing	102,235	40,985	27,726	13,569	20,610
Pipeline and storage	77,858	70,286	5,293	11,814	—
Other nonutility	392	818	752	1,323	9,215
Eliminations	237	201	34	—	—
Consolidated	$ 382,616	$ 348,655	$ 193,695	$ 187,840	$ 155,331

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(1) Financial results for fiscal 2006 include a $22.9 million pre-tax loss for the impairment of the West Texas Division's irrigation assets.

(2) Financial results and operating data for fiscal 2005 include the operations of our Mid-Tex and Atmos Pipeline — Texas divisions, from October 1, 2004, the date of acquisition.

(3) Financial results for fiscal 2004 include a $5.9 million pre-tax gain on the sale of our interest in U.S. Propane, L.P. and Heritage Propane Partners, L.P.

(4) Financial results and operating data for fiscal 2003 include the operations of MVG from December 3, 2002, the date of acquisition.

(5) Throughput and sales volumes reflect segment operations, including intercompany sales and transportation amounts.

(6) Beginning in fiscal 2004, we reclassified our regulatory cost of removal obligation from accumulated depreciation to a liability. The amounts presented above for property, plant and equipment, working capital and total assets reflect this reclassification for all periods presented. This reclassification did not impact our financial position, results of operations or cash flows as of and for the years ended September 30, 2003 and 2002.

(7) Long-term debt excludes current maturities. Short-term debt is comprised of current maturities of long-term debt and short-term debt.

(8) Pipeline and storage operations were not reported as a segment prior to fiscal 2003.

The Offering

Common Stock Offered	5,500,000 shares
Shares Outstanding After the Offering	87,239,516 shares
Use of Proceeds	We estimate that our net proceeds from this offering, without exercise of the underwriters' option to purchase additional shares of common stock and after deducting the underwriting discount and commissions and estimated offering expenses payable by us, will be approximately $166.8 million. We intend to use the net proceeds of this offering to repay short-term debt outstanding under our commercial paper program.
NYSE Symbol	ATO

The number of shares outstanding after the offering is based on our shares outstanding on September 30, 2006, and excludes 1,573,381 shares reserved for issuance under outstanding options and share unit awards as of September 30, 2006. This number assumes that the underwriters' option is not exercised. If the underwriters' option is exercised, we will issue and sell up to an additional 825,000 shares.

See "Risk Factors" beginning on page 1 of the accompanying prospectus and other information included and incorporated by reference in this prospectus supplement and the accompanying prospectus for a discussion of the factors you should consider carefully before deciding to invest in our common stock.

USE OF PROCEEDS

We estimate that we will receive net proceeds from this offering of approximately $166.8 million ($191.9 million if the underwriters' option is exercised in full), after deducting the underwriting discount and commissions and estimated offering expenses payable by us.

We intend to use the estimated net proceeds of this offering to repay short-term debt outstanding under our commercial paper program. As of December 7, 2006, we had $345.7 million of our commercial paper outstanding under our commercial paper program with a weighted average interest rate of approximately 5.49 percent and a weighted average maturity of approximately 11 days. We use our commercial paper program for our working capital, capital expenditures and other general corporate purposes.

To the extent we issue shares of common stock generating net proceeds in excess of the estimated amount, we intend to use such additional net proceeds to repay additional short-term debt outstanding under our commercial paper program.

CAPITALIZATION

The following table presents our short-term debt and capitalization as of September 30, 2006, on an actual basis and on an as adjusted basis to give effect to the application of approximately $166.8 million of estimated net proceeds of this offering to repay short-term debt as if it had occurred on such date. You should read this table in conjunction with the section "Use of Proceeds" and our consolidated financial statements and related notes included in our annual report on Form 10-K for the year ended September 30, 2006, which is incorporated by reference in this prospectus supplement.

	As of September 30, 2006	
	Actual	As Adjusted
	(in thousands)	
Short-term debt		
Current portion of long-term debt	$ 3,186	$ 3,186
Other short-term debt	382,416	215,630
Total short-term debt	$ 385,602	$ 218,816
Long-term debt, less current portion	$2,180,362	$2,180,362
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; 81,739,516 shares issued and outstanding, actual; 87,239,516 shares issued and outstanding, as adjusted(1)	$ 409	$ 437
Additional paid-in capital	1,467,240	1,633,998
Retained earnings	224,299	224,299
Accumulated other comprehensive loss	(43,850)	(43,850)
Shareholders' equity	1,648,098	1,814,884
Total capitalization(2)	$3,828,460	$3,995,246

(1) The number of shares of common stock issued and outstanding excludes 1,573,381 shares of our common stock then issuable upon exercise of outstanding options and share unit awards and up to 825,000 shares issuable upon the exercise of the underwriters' option.

(2) Total capitalization excludes the current portion of long-term debt and other short-term debt.

MARKET PRICE OF COMMON STOCK AND DIVIDENDS

Our common stock is listed on the New York Stock Exchange under the symbol "ATO." The following table indicates the high and low closing prices of our common stock, as reported by the New York Stock Exchange, and the dividends that we paid per share during the periods indicated.

	High	Low	Cash Dividends Paid
Quarter Ending			
December 31, 2006 (through December 7, 2006)	$33.01	$28.45	
Quarter Ended			
September 30, 2006	$29.11	$27.96	$0.315
June 30, 2006	27.91	26.00	0.315
March 31, 2006	27.00	26.10	0.315
December 31, 2005	28.36	25.79	0.315
Quarter Ended			
September 30, 2005	$29.76	$28.23	$0.310
June 30, 2005	28.87	25.94	0.310
March 31, 2005	29.09	26.19	0.310
December 31, 2004	27.43	24.85	0.310
Quarter Ended			
September 30, 2004	$25.86	$24.61	$0.305
June 30, 2004	26.05	23.68	0.305
March 31, 2004	26.86	24.32	0.305
December 31, 2003	24.99	24.15	0.305

The last reported sale price of our common stock on the New York Stock Exchange on December 7, 2006 was $32.07 per share.

The quarterly dividends of $0.315 per share paid during the four quarters of fiscal 2006 yielded an annual dividend for fiscal 2006 of $1.26 per share. Our board of directors has declared a dividend of $0.32 per share payable on December 11, 2006 to shareholders of record on November 27, 2006.

Dividends on our shares of common stock are payable at the discretion of our board of directors out of legally available funds. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors, including compliance with the restrictions in our debt agreements.

BUSINESS

Overview

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. We are one of the country's largest natural-gas-only distributors based on number of customers and one of the largest intrastate pipeline operators in Texas based upon miles of pipe. As of September 30, 2006, we distributed natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our seven regulated utility divisions, which covered service areas in 12 states. 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. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to certain of our utility divisions and to third parties.

Operating Segments

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

Utility Segment

We operated our utility segment through the following seven regulated natural gas utility divisions during the year ended September 30, 2006:

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

Effective October 1, 2006, the Kentucky and Mid-States divisions were combined.

Our natural gas utility distribution business is seasonal and dependent on weather conditions in our service areas. 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.

In addition to weather, our financial results are affected by the cost of natural gas and economic conditions in the areas that we serve. Higher gas costs, which we are generally able to pass through to our customers under purchased gas adjustment clauses, may cause customers to conserve or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also 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.

The effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which are now approved by the regulators for over 90 percent of residential and commercial meters in our service areas. WNA allows 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.

Prior to October 1, 2006, our largest division, the Mid-Tex Division, did not have WNA. However, its operations benefited from a rate structure that combined a monthly customer charge with a declining block rate schedule to partially mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provided for the recovery of most of our fixed costs for such operations under most weather conditions. However, this rate structure was not as beneficial during periods where weather was significantly warmer than normal.

In May 2006, the Mid-Tex Division filed a Statement of Intent seeking additional annual revenues of $60 million and several rate design changes including WNA. In July 2006, the Railroad Commission of Texas (RRC) approved an interim and a permanent WNA, effective October 1, 2006 for the Mid-Tex Division. The agreement provided that the interim WNA will be based on the use of 30 years of weather history, while the permanent WNA will allow the parties to contest the appropriate period of weather data to use in calculating normal weather. The permanent WNA will also be modified or adjusted to conform to the rate design that the RRC ultimately approves in the case. Additionally, in May 2006, we agreed to a settlement with the Louisiana Public Service Commission (LPSC) that authorized the implementation of WNA in our Louisiana Division effective December 1, 2006.

As of September 30, 2006, we had, or received regulatory approvals for, WNA for our customer meters in the following service areas for the following periods:

Georgia	October — May
Kansas	October — May
Kentucky	November — April
Louisiana[1]	December — March
Mid-Tex[1]	October — May
Mississippi	November — April
Tennessee	November — April
Amarillo, Texas	October — May
West Texas	October — May
Lubbock, Texas	October — May
Virginia	January — December

[1] Effective beginning with the 2006-2007 winter heating season.

Our natural gas supply comes from a variety of third-party providers and from gas held in storage. We anticipate that the natural gas supply for the upcoming winter heating season will be provided by a variety of suppliers, including independent producers, marketers and pipeline companies, in addition to withdrawals of gas from storage. Additionally, the natural gas supply for our Mid-Tex Division includes peaking and spot purchase agreements. We also contract for storage service in underground storage facilities on many of the

interstate pipelines serving us. We estimate the peak-day availability of natural gas supply from long-term contracts, short-term contracts and withdrawals from underground storage to be approximately 4.2 Bcf. The peak-day demand for our utility operations in fiscal 2006 was on December 8, 2005, when sales to customers reached approximately 3.4 Bcf.

Supply arrangements are contracted from our suppliers on a firm basis with various terms at market prices. The firm supply consists of both base load and swing supply quantities. 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 suppliers through a competitive bidding process by 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 2006 were Anadarko Energy Services, BP Energy Company, Chesapeake Energy Marketing, Inc., ConocoPhillips Company, Cross Timbers Energy Services, Inc., Devon Gas Services, L.P., Enbridge Marketing (US), L.P., PPM Energy, Inc., 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.

Also, 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 statutes or regulations. 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.

We receive gas deliveries for all of our utility divisions, except for our Mid-Tex Division, through 37 pipeline transportation companies, both interstate and intrastate, to satisfy our natural gas needs. 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 by our Atmos Pipeline – Texas Division.

The following is a brief description of our natural gas utility divisions. For more information see "Item 1. Business" in our annual report on form 10-K for the year ended September 30, 2006.

Atmos Energy Colorado-Kansas Division. Our Colorado-Kansas Division operates in Colorado, Kansas and the southwestern corner of Missouri and is regulated by each respective state's public service commission with respect to accounting, rates and charges, operating matters and the issuance of securities. We operate under terms of non-exclusive franchises granted by the various cities. Rates in our Kansas service area are subject to WNA. The principal transporters of the Colorado-Kansas Division's gas supply requirements are Colorado Interstate Gas Company, Northwest Pipeline, Public Service Company of Colorado and Southern Star Central Pipeline. Additionally, the Colorado-Kansas Division purchases substantial volumes from producers that are connected directly to its distribution system.

Atmos Energy Kentucky Division. Our Kentucky Division operates in Kentucky and is regulated by the Kentucky Public Service Commission (KPSC), which regulates utility services, rates, issuance of securities and other matters. We operate in various incorporated cities pursuant to non-exclusive franchises granted by

these cities. The sale of natural gas for use as vehicle fuel in Kentucky is unregulated. In February 2006, the KPSC approved our request to continue the performance-based ratemaking mechanism for an additional five-year period. Under the performance-based mechanism, we and our customers jointly share in any actual gas cost savings achieved when compared to pre-determined benchmarks. Our rates are also subject to WNA. The Kentucky Division's gas supply is delivered primarily by Midwestern Pipeline, Tennessee Gas Pipeline Company, Texas Gas Transmission, LLC and Trunkline Gas Company. As noted below, this division was combined with the Mid-States Division effective October 1, 2006.

Atmos Energy Louisiana Division. Our Louisiana Division operates in Louisiana and serves the metropolitan area of Monroe, the suburban areas of New Orleans and western Louisiana. Our Louisiana Division is regulated by the Louisiana Public Service Commission, which regulates utility services, rates and other matters. We operate most of our service areas pursuant to a non-exclusive franchise granted by the governing authority of each area. 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 natural gas marketing segment. Effective beginning with the 2006-2007 winter heating season, rates in our Louisiana service area will be subject to WNA. The principal transporters of the Louisiana Division's gas supply requirements are Acadian Pipeline, Gulf South, Louisiana Intrastate Gas Company, Texas Gas Transmission, LLC and Trans Louisiana Gas Pipeline, Inc., a subsidiary of Atmos Pipeline and Storage, LLC.

Atmos Energy Mid-States Division. Our Mid-States Division operates in Georgia, Illinois, Iowa, Missouri, Tennessee and Virginia. In each of these states, our rates, services and operations as a natural gas distribution company are subject to general regulation by each state's public service commission. We operate in each community, where necessary, under a franchise granted by the municipality for a fixed term of years. In Tennessee and Georgia, we have WNA and a performance-based rate program, which provides incentives for us to find ways to lower costs and share the cost savings with our customers. We have WNA in our Virginia service area that covers the entire year. Our Mid-States Division is served by 13 interstate pipelines; however, the majority of the volumes are transported through Columbia Gulf, East Tennessee Pipeline, Southern Natural Gas and Tennessee Gas Pipeline. The Kentucky Division was combined with the Mid-States Division effective October 1, 2006.

Atmos Energy Mid-Tex Division. Our Mid-Tex Division includes the natural gas distribution operations that operate in the north-central, eastern and western parts of Texas. The Mid-Tex Division purchases, distributes and sells natural gas in approximately 550 cities and towns, including the 11-county Dallas-Fort Worth metropolitan area. This division currently operates under a system-wide rate structure. The governing body of each municipality we serve has original jurisdiction over all utility rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. We operate pursuant to non-exclusive franchises granted by the municipalities we serve, which are subject to renewal from time to time. The 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. Effective beginning with the 2006-2007 winter heating season, rates in our Mid-Tex service area will be subject to WNA.

Atmos Energy Mississippi Division. Our Atmos Energy Mississippi Division operates in Mississippi and is regulated by the Mississippi Public Service Commission (MPSC) with respect to rates, services and operations. We operate under non-exclusive franchises granted by the municipalities we serve. Through fiscal 2005, we operated under a rate structure that allowed us, over a five-year period, to recover a portion of our integration costs associated with the MVG acquisition and operations and maintenance costs in excess of an agreed-upon benchmark. In addition, we were required to file for rate adjustments based on our expenses every six months. Effective October 1, 2005, our rate design was modified to substitute the original agreed-upon benchmark with a sharing mechanism to allow the sharing of cost savings above an allowed return on equity level. Further, beginning October 1, 2005, we moved from a semi-annual filing process to an annual filing process. We also have WNA in Mississippi. This division's gas supply is delivered primarily by

Gulf South Pipeline Company, Tennessee Gas Pipeline Company, Southern Natural Gas Company, Texas Eastern Transmission, Texas Gas Transmission, LLC, Trunkline Gas Co. LLC and Enbridge Marketing, LP.

Atmos Energy West Texas Division. Our West Texas Division operates in Texas in three primary service areas: the Amarillo service area, the Lubbock service area and the West Texas service area. Similar to our Mid-Tex Division, the governing body of each municipality we serve has original jurisdiction over all utility rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. We operate pursuant to non-exclusive franchises granted by the municipalities we serve, which are subject to renewal from time to time. The 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. We have WNA in each of our service areas. Our West Texas Division receives transportation service from ONEOK Pipeline. In addition, the West Texas Division purchases a significant portion of its natural gas supply from Pioneer Natural Resources, which is connected directly to our Amarillo, Texas, distribution system.

Natural Gas Marketing Segment

Our natural gas marketing and other nonutility segments, which are organized under Atmos Energy Holdings, Inc. (AEH), have operations in 22 states. Through September 30, 2003, Atmos Energy Marketing, LLC, together with its wholly-owned subsidiaries Woodward Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc., comprised our natural gas marketing segment. Effective October 1, 2003, our natural gas marketing segment was reorganized. The operations of Atmos Energy Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc. were merged into Woodward Marketing, L.L.C., which was renamed Atmos Energy Marketing, LLC (AEM).

AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas consumers primarily in the southeastern and midwestern states and to our Kentucky, Louisiana and Mid-States divisions. These services primarily consist of 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 management through the use of derivative products. We use proprietary and customer-owned transportation and storage assets to provide the various services our customers request. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we participate in natural gas storage transactions in which we seek to capture the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at favorable prices to lock in a gross profit margin. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

AEM's management of natural gas requirements involves the sale of natural gas and the management of storage and transportation supplies under contracts with customers generally having one- to two-year terms. AEM also sells natural gas to some of its industrial customers on a delivered burner tip basis under contract terms from 30 days to two years. At September 30, 2006, AEM had a total of 679 industrial, 73 municipal and 289 other customers.

Pipeline and Storage Segment

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline – Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage,

LLC (APS). The Atmos Pipeline – Texas 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 arrangements, lending and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline and lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands. Both of these services are primarily offered on our Atmos Pipeline – Texas system. These operations represent 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.

APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

In May 2006, APS announced plans to form a joint venture with a local natural gas producer to construct a natural gas gathering system in Eastern Kentucky. Referred to as the Straight Creek Project, the new system is expected to relieve severe gas gathering and transportation constraints that historically have burdened natural gas producers in the area and should improve delivery reliability to natural gas customers. In October 2006, the Federal Energy Regulatory Commission (FERC) issued a declaratory order finding that the Straight Creek Project will be exempt from FERC jurisdiction. The joint venture provides APS the opportunity to apply its expertise to the upstream gathering business.

Other Nonutility Segment

Our other nonutility segment consists primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. which are wholly-owned by our subsidiary, Atmos Energy Holdings, Inc. Through AES, we provide natural gas management services to our utility operations, other than the Mid-Tex Division. These services, which began in April 2004, include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices in exchange for revenues that are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Through January 2004, United Cities Propane Gas, Inc., a wholly-owned subsidiary of Atmos Energy Holdings, Inc., owned an approximate 19 percent membership interest in U.S. Propane, L.P. (USP), a joint venture formed in February 2000 with other utility companies to own a limited partnership interest in Heritage Propane Partners, L.P. (Heritage), a publicly-traded marketer of propane through a nationwide retail distribution network. During fiscal 2004, we sold our interest in USP and Heritage. As a result of these transactions, we no longer have an interest in the propane business.

Ratemaking Activity

Overview

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

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas 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's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments because they provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit (which is defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. 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 hedges to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility and its customers.

The following table summarizes some information regarding our ratemaking jurisdictions. This information is for regulatory purposes only and may not be representative of our actual financial position.

Jurisdictional Rate Summary

Division	Jurisdiction	Effective Date of Last Rate Action	Rate Base (Thousands)(1)	Authorized Rate of Return(1)	Authorized Return on Equity(1)
Atmos Pipeline — Texas	Texas	5/24/04	$417,111	8.258%	10.00%
Colorado-Kansas	Colorado	7/1/05	84,711	8.95%	11.25%
	Kansas	3/1/04	(2)	(2)	(2)
Kentucky	Kentucky	12/21/99	(2)	(2)	(2)
Louisiana	Trans LA	10/1/04	81,645	9.14%	10.50% - 11.50%
	LGS	10/1/04	170,358	9.23%	10.88% - 11.50%
Mid-States	Georgia	12/20/05	62,380	7.57%	10.13%
	Illinois	11/1/00	24,564	9.18%	11.56%
	Iowa	3/1/01	5,000	(2)	11.00%
	Missouri	10/14/95	(2)	10.58%	12.15%
	Tennessee	11/15/95	111,970	(2)	(2)
	Virginia	8/1/04	30,672	8.46% - 8.96%	9.50% - 10.50%
Mid-Tex	Texas	5/24/04	769,721	8.258%	10.00%
Mississippi	Mississippi	1/1/05	196,801	8.23%	9.80%
West Texas	Amarillo	9/1/03	36,844	9.88%	12.00%
	Lubbock	3/1/04	43,300	9.15%	11.25%
	West Texas	5/1/04	87,500	8.77%	10.50%

See footnotes on following page.

Division	Jurisdiction	Effective Date of Last Rate Action	Authorized Debt/ Equity Ratio	Bad Debt Rider[5]	WNA	Performance-Based Rate Program[3]
Atmos Pipeline – Texas	Texas	5/24/04	50/50	No	N/A	N/A
Colorado-Kansas	Colorado	7/1/05	52/48	No	No	No
	Kansas	3/1/04	(2)	Yes	Yes	No
Kentucky	Kentucky	12/21/99	(2)	No	Yes	Yes
Louisiana	Trans LA	10/1/04	50/50	No	(4)	No
	LGS	10/1/04	53/47	No	(4)	No
Mid-States	Georgia	12/20/05	55/45	No	Yes	Yes
	Illinois	11/1/00	67/33	No	No	No
	Iowa	3/1/01	57/43	No	No	No
	Missouri	10/14/95	(2)	No	No	No
	Tennessee	11/15/95	56/44	No	Yes	Yes
	Virginia	8/1/04	52/48	Yes	Yes	No
Mid-Tex	Texas	5/24/04	50/50	No	(4)	No
Mississippi	Mississippi	1/1/05	47/53	No	Yes	No
West Texas	Amarillo	9/1/03	50/50	Yes	Yes	No
	Lubbock	3/1/04	50/50	No	Yes	No
	West Texas	5/1/04	50/50	No	Yes	No

(1) The rate base and authorized rate of return presented in this table are the rate base and rate of return from the last base rate case for each jurisdiction. These rate bases and rates of return are not necessarily indicative of current or future rate bases or rates of return.

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

(4) During 2006, our Louisiana and Mid-Tex Divisions received authorization to implement WNA beginning in the 2006-2007 winter heating season.

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

Recent Ratemaking Activity

Our current rate strategy focuses on seeking rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns due to weather-related variability, declining use per customer and energy conservation, also known as decoupling. Additionally, we are seeking to stratify rates for low income households and to recover the gas cost portion of our bad debt expense.

Improving rate design is a long-term process. In the interim, we are addressing regulatory lag issues by directing discretionary capital spending to jurisdictions that permit us to recover our investment in a timely manner and filing rate cases on a more frequent basis to minimize the regulatory lag to keep our actual returns more closely aligned with our allowed returns.

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Approximately 97 percent of our utility revenues in the fiscal years ended September 30, 2006, 2005 and 2004 were derived from sales at rates set by or subject to approval by local or state authorities. Net annual revenue increases resulting from ratemaking activity totaling $39.0 million, $6.3 million and $16.2 million became effective in fiscal 2006, 2005 and 2004 as summarized below:

Division	Most Recent Effective Date	Most Recent Rate Action	Jurisdiction	Increase (Decrease) to Revenue for the Year Ended September 30 2006	2005	2004
					(In thousands)	
Atmos Pipeline – Texas	8/1/06	GRIP(1)	Texas	$ 5,205	$1,802	$ —
Colorado-Kansas	4/1/04	Show Cause	Colorado	—	—	(1,900)
	1/1/06	Ad Valorem Tax	Kansas	1,565	—	—
	3/1/04	Rate Case	Kansas	—	—	2,500
Louisiana	2/1/06	Stable Rate Filing (2)	LGS	3,326	—	—
	10/1/04	Stable Rate Filing (2)	LGS	—	225	—
Mid-States	8/1/04	Rate Case	Virginia	—	—	372
	12/20/05	Rate Case	Georgia	409	—	—
Mid-Tex	2/1/06	GRIP(1)	Texas	25,313	—	—
Mississippi	(3)	Stable Rate Filing (2)	Mississippi	—	4,300	10,545
	11/1/05	Rate Restructuring	Mississippi	(600)	—	—
West Texas	12/1/05	GRIP(1)	Lubbock	1,263	—	—
	3/1/04	Rate Case	Lubbock	—	—	1,525
	3/1/06	GRIP(1)	West Texas	2,539	—	—
	5/1/04	Rate Case	West Texas	—	—	3,200
				$39,020	$6,327	$16,242

(1) In 2003, the Texas Legislature approved the Gas Reliability Infrastructure Program (GRIP) which allows natural gas utilities the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. Natural gas utilities that enter the program will be required to file a complete rate case at least once every five years.

(2) A stable rate filing is a regulatory mechanism designed to allow us to refresh our rates on a periodic basis without filing a formal rate case.

(3) The MPSC had formerly required that we file for rate adjustments every six months. Through May 2005, rate filings were made in May and November of each year and the rate adjustments typically became effective in June and December. See further discussion under the recent ratemaking activity for our Mississippi Division below.

Additionally, the following ratemaking efforts were initiated during fiscal 2006 but had not been completed as of September 30, 2006:

Division	Rate Action	Jurisdiction	Revenue Requested (in thousands)
Louisiana	Stable Rate Filing (1)	LGS	$10,753
Mid-States	Rate Case	Missouri	3,396
	Rate Proceeding(2)	Tennessee	3,400
Mid-Tex	System-Wide Case	Texas	60,844
			$78,393

(1) The Louisiana Division has included the rate stabilization clause increase in rates. The increase is subject to refund, pending final resolution of the stable rate filing.

(2) The Tennessee rate proceeding was settled in October 2006. See below for information regarding the settlement.

Our recent ratemaking activity is discussed in greater detail below.

Atmos Pipeline-Texas. In April 2006, Atmos Pipeline-Texas made a filing under Texas' Gas Reliability Infrastructure Program (GRIP) to include in rate base approximately $21.6 million of pipeline capital expenditures incurred during calendar year 2005, which should result in additional annual revenues of approximately $3.3 million. The RRC approved this filing in July 2006 and these new charges were included in the monthly customer charge beginning in August 2006.

In September 2005, Atmos Pipeline-Texas made a GRIP filing to include in rate base approximately $10.6 million of pipeline capital expenditures incurred during calendar year 2004, which resulted in approximately $1.9 million in additional annual revenue. In December 2004, Atmos Pipeline-Texas made a GRIP filing to include in rate base approximately $12.0 million of pipeline capital expenditures made by TXU Gas during calendar year 2003, which resulted in additional annual revenues of approximately $1.8 million.

Atmos Energy Colorado-Kansas Division. In December 2005, the Colorado-Kansas Division filed its second annual ad valorem tax surcharge for $1.6 million. The surcharge is designed to collect Kansas property taxes in excess of the amount in the Colorado-Kansas Division's most recent general rate case. We began to bill this surcharge in January 2006.

In July 2004, the Colorado Public Utility Commission ordered us to issue a one-time credit to our Colorado customers of $1.9 million. The agreement was a result of an inquiry by the Colorado Office of Consumer Counsel related to our earnings in Colorado. The staff of the Colorado Public Utility Commission was also a party to the agreement.

In May 2003, the Colorado-Kansas Division filed a rate case with the Kansas Corporation Commission for approximately $7.4 million in additional annual revenues. In January 2004, the Kansas Corporation Commission approved an agreement that allowed a $2.5 million increase in our rates effective March 2004. Additionally, the agreement allowed us to increase our monthly customer charges from $5 to $8, provided that we would not file another full rate application prior to September 2005. WNA became effective in Kansas in October 2003 in accordance with the Kansas Corporation Commission's ruling in May 2003.

Atmos Energy Kentucky Division. In February 2006, the KPSC approved our request to continue our Performance Based Ratemaking (PBR) mechanism for an additional five year period. The PBR establishes predetermined gas cost benchmarks and provides incentives to us for purchasing gas supply below those benchmark costs.

In February 2005, the Attorney General of the State of Kentucky filed a complaint with the Kentucky Public Service Commission (KPSC) alleging that our rates were producing revenues in excess of reasonable levels. We answered the complaint and filed a motion to dismiss with the KPSC. In February 2006, the KPSC

issued an order denying our motion to dismiss but stated that the Attorney General had not met his burden of proof concerning his complaint. In March 2006, the KPSC set a procedural schedule for the case. The Attorney General is currently conducting discovery. A hearing should be scheduled for early 2007. We believe that the Attorney General will not be able to demonstrate that our present rates are in excess of reasonable levels.

Atmos Energy Louisiana Division. In September 2005, the Louisiana Public Service Commission (LPSC) consolidated several then-existing dockets. These dockets included a separate proceeding for the renewal of the Rate Stabilization Clause (RSC) for each of the LGS and TransLa Gas service areas; resolution of the outstanding 2003 RSC filing for the LGS service area; and our request for approval of a decoupling mechanism to stabilize margins in both the LGS and TransLa service areas.

On May 25, 2006, the LPSC voted to approve a settlement which included a modified WNA providing for partial decoupling, renewal of the RSC for both the LGS and TransLa service areas with provisions that will reduce regulatory lag and a refund to customers of approximately $0.4 million for the LGS service areas that previously had been deferred. The first RSC filing was in August 2006 for approximately $10.8 million, based on a test year ended December 31, 2005, for the LGS service area. The increase is subject to refund, pending final approval by the LPSC. The first filing for the TransLa service area will be made by December 31, 2006, for the test period ending September 30, 2006, with an effective rate adjustment of April 1, 2007. WNA for both service areas will be in effect for an initial three-year period beginning with the winter of 2006-2007. In the third quarter of fiscal 2006, $6.2 million in deferred revenue associated with the 2003 RSC rate adjustment was recognized.

On August 29, 2005, Hurricane Katrina struck the Gulf Coast, inflicting significant damage to our eastern Louisiana operations. The hardest hit areas in our service territory were in Jefferson, St. Tammany, St. Bernard and Plaquemines parishes. Although service has been restored for many of our customers, a significant number of customers will not require gas service for some time, if ever, because of sustained damages. We began implementing new rates, subject to refund, in September 2006 that reflected the reduction of approximately 26,500 customers and included a request to recover costs attributable to Hurricane Katrina. We cannot accurately determine what regulatory actions, if any, may be taken by the regulators with respect to this filing or our ability to fully recover all costs incurred as a result of the storm.

During the second quarter of 2005, the Louisiana Division implemented a rate increase of $3.3 million in its LGS service area. This increase resulted from our RSC filing in 2004 and was subject to refund, pending the final resolution of that filing. As the rate increase was subject to refund, we did not recognize the effects of this increase in our results of operations during fiscal 2005 or the first three quarters of fiscal 2006.

During fiscal 2004, the Louisiana Public Service Commission approved tariff revisions for our LGS service area totaling $0.2 million that became effective in October 2004.

In October 2002, Atmos received written notification from the Executive Secretary of the LPSC asserting that a monthly facilities fee of approximately $0.6 million charged since July 2001 to Atmos by Trans Louisiana Gas Pipeline, Inc., a wholly-owned subsidiary of Atmos, pursuant to a contract between the parties, was excessive. The Executive Secretary asserted that all monthly facilities fees in excess of approximately $0.1 million from July 2001 should be refunded to ratepayers with interest. In October 2003, the LPSC unanimously voted to approve an agreement to allow us to charge a facilities fee of approximately $0.5 million per month (subject to future escalation) beginning November 2003 for a period of 14 years. No retroactive adjustments were required under this agreement.

Atmos Energy Mid-States Division. In April 2006, we filed a rate case in our Missouri service area seeking a rate increase of $3.4 million. We are proposing to consolidate the rates for our Missouri properties into three sets of regional rates and consolidate the current purchased gas adjustment (PGA) into one statewide PGA. We are also proposing a WNA mechanism. An evidentiary hearing was completed on December 5, 2006, with an order expected to be issued in March 2007.

In March 2006, we received notification from the Tennessee Regulatory Authority (TRA) that it disagreed with the way we calculated amounts under its performance-based rate mechanism, which resulted in a one-time $3.3 million income reduction during the second quarter of fiscal 2006. We believe the original calculations were correct and have appealed the TRA's decision.

During the third quarter of fiscal 2005, we filed a rate case in our Georgia service area seeking a rate increase of $4.0 million. In December 2005, the Georgia Public Service Commission (GPSC) approved a $0.4 million increase. In January 2006, we filed an appeal of the GPSC's decision in the Superior Court of Fulton County. Oral arguments were held on September 7, 2006 before the Fulton County Superior Court. The court affirmed the commission's order. We are considering further appeal.

In November 2005, we received a notice from the TRA that it was opening an investigation into allegations by the Consumer Advocate and Protection Division of the Tennessee Attorney General's Office that we were overcharging customers in parts of Tennessee by approximately $10 million per year. We responded to numerous data requests from the TRA Staff. In April 2006, the TRA Staff filed a Report and Recommendation in which it recommended that the TRA convene a contested case procedure for the purpose of establishing a fair and reasonable return. The TRA convened to consider the Staff's recommendation on May 15, 2006 and set a procedural schedule. A hearing was held from August 29, 2006 through August 31, 2006. Of the $10 million rate reduction requested by the Consumer Advocate and Protection Division, the TRA approved on October 27, 2006 a $6.1 million reduction to future rates.

In February 2004, the Mid-States Division filed a rate case with the Virginia Corporation Commission (VCC) to request a $1.0 million increase in our base rates, WNA and recovery of the gas cost component of bad debt expense. The VCC granted a rate increase in November 2004 of $0.4 million that was retroactively effective to July 27, 2004. Additionally, the VCC authorized WNA beginning in July 2005 and the ability to recover the gas cost component of bad debt expense.

Atmos Energy Mid-Tex Division. The following is a discussion of our recent ratemaking activity for our Mid-Tex Division.

<u>Rate Case</u>. During fiscal 2006, we received "show cause" resolutions from approximately 80 cities served by our Mid-Tex Division, including the City of Dallas, which require us to demonstrate that existing distribution rates in the Mid-Tex Division are just and reasonable. In May 2006, in response to these resolutions, we filed a Statement of Intent to increase rates on a division-wide basis. By agreement with the cities, the "show cause" resolutions were consolidated and became part of the Mid-Tex Division's first rate case before the RRC since we acquired the TXU Gas operations in October 2004. In this rate proceeding, we are seeking incremental annual revenues in the Mid-Tex Division of approximately $60 million and several rate design changes, including WNA, revenue stabilization and recovery of the gas cost component of bad debt expense.

In exchange for an agreement to provide the intervening parties in the proceeding additional time to prepare for the hearing, we obtained agreement from the intervenors to implement WNA in the rates for the Mid-Tex Division for the 2006-2007 winter season, which has been approved by the RRC, and to implement WNA in the final rates in this proceeding. The hearing in this proceeding was concluded on November 17, 2006, and a decision is due from the RRC no later than April 2007. During the hearing, the principal issues raised by the cities included the Mid-Tex Division's rate of return, the reduction of rate base for the accumulated deferred federal income taxes and investment tax credits associated with the TXU Gas operations prior to our acquisition, the methodology used by us to allocate certain shared services expenses to the division and the inclusion of certain items in operation and maintenance expenses.

In addition, under applicable statutes, the RRC is reviewing the interim rate adjustments that were previously granted in response to the Mid-Tex Division's prior GRIP filings and our acquisition of the TXU Gas operations for consistency with the public interest. Any increase that the RRC may grant in this case would be effective prospectively from the date of the final order. However, any decrease that may be ordered by the RRC would be effective from May 31, 2006 pursuant to the agreement with the intervenors for

consolidation of the show cause resolutions and the Statement of Intent filing. Any disallowance related to the previously granted GRIP interim rate adjustments would be refunded to customers with interest beginning some time after the issuance of a final order in this proceeding.

While the decision of the RRC in this case cannot be predicted with certainty, we believe that we have adequately demonstrated to the RRC that the Mid-Tex Division is entitled to receive an increase in annual revenues and that the remaining rate design changes should be implemented.

GRIP Filings. In March 2006, the Mid-Tex Division made a GRIP filing to include in rate base approximately $62.2 million of distribution capital expenditures incurred during calendar year 2005, which we estimate would result in additional annual revenues of approximately $11.9 million. The RRC approved this filing in August 2006, and the new customer charges were implemented in September 2006 billings to customers.

In September 2005, the Mid-Tex Division made a GRIP filing to include in rate base approximately $29.4 million of distribution capital expenditures incurred during calendar year 2004, which currently provides additional annual revenues of approximately $6.7 million. The RRC approved this filing in January 2006, and these new charges were included in the monthly customer charge beginning in February 2006.

In December 2004, the Mid-Tex Division made a GRIP filing to include in rate base approximately $32.0 million of distribution capital expenditures made by TXU Gas during calendar year 2003, which currently provides additional annual revenues of approximately $6.7 million. New monthly customer charges were implemented in October 2005.

Other Regulatory Matters. In September 2006, the Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately $24 million in refunds of amounts that were overcollected from customers between July 2005 and June 2006. The Mid-Tex Division has requested and received approval to refund these amounts over a six-month period beginning in November 2006.

In September 2004, the Mid-Tex Division filed its 36-Month Gas Contract Review with the RRC. This proceeding involves a review for reasonableness of gas purchases totaling $2.2 billion made by the Mid-Tex Division from November 2000 through October 2003. A hearing on this matter was held before the RRC in June 2005. The parties negotiated a unanimous settlement agreement providing for a refund of $8 million to customers over a three-year period and for reimbursement of parties' expenses without recovery from customers. The RRC approved the settlement on September 12, 2006. Refunds to customers began in the first quarter of fiscal year 2007.

The Mid-Tex Division is also pursuing an appeal to the Travis County District Court of the Final Order in its last system-wide rate case completed in May 2004 to obtain a return of and on its investment associated with the Poly I replacement pipe that was originally disallowed in its rate case completed in May 2004. The case was argued before the Travis County District Court in July 2006. The Court ruled to uphold the Commission's final order. Steps are being taken to perfect an appeal to the Court of Appeals in Travis County.

Atmos Energy Mississippi Division. Through the first quarter of fiscal 2005, the MPSC required that we file for rate adjustments every six months. Rate filings were made in May and November of each year and the rate adjustments typically became effective in the following July and January.

During the second quarter of fiscal 2005, we agreed with the MPSC to suspend our May 2005 semi-annual filing to allow sufficient time for us and the MPSC to undertake a comprehensive review in an effort to improve our rate design and the ratemaking process. Effective October 2005, our rate design was modified to substitute the original agreed-upon benchmark with a sharing mechanism to allow the sharing of cost savings above an allowed return on equity level. Further, we moved from a semi-annual filing process to an annual filing process. Additionally, our WNA period begins on November 1 instead of November 15, and ends on April 30 instead of May 15. Also, we now have a fixed monthly customer base charge which makes a portion of our earnings less susceptible to usage. As part of the rate design restructuring, we agreed to reduce

our rates by approximately $0.6 million. We made our first annual filing under this new structure in September 2006 requesting no change in rates.

In September 2004, the MPSC originally disallowed certain deferred costs totaling $2.8 million. In connection with the modification of our rate design described above, the MPSC decided to allow these costs, and we included these costs in our rates in October 2005.

In June 2006, the MPSC approved a pilot program whereby Trans Louisiana Gas Pipeline (TLGP) will provide asset management services to the Mississippi Division. The asset management program allows TLGP to market certain off-peak gas supply assets, such as company-owned or leased storage and pipeline capacity, on a recallable basis. In return, TLGP will share net positive benefits of the asset management program with Mississippi ratepayers. The pilot program runs from June 1, 2006 to April 30, 2007 and may be extended by the MPSC upon application by Atmos.

In October 2003, the MPSC issued a final order that denied our May 2003 request for a rate increase of $5.8 million. In January 2004, the MPSC authorized additional annual revenue of $5.9 million on our November 2003 filing, which became effective in December 2003. In September 2004, the MPSC authorized additional annualized revenue of $4.7 million on our May 2004 filing, which became effective in June 2004.

We filed our second semiannual filing for 2004 in November 2004, requesting rate adjustments of $6.0 million in annualized revenue. The MPSC allowed us to include $3.0 million in annualized revenue in our rates effective January 2005. In February 2005, we entered into an agreement with the Mississippi Public Utilities Staff that provides for an additional $1.3 million in annualized revenue that was retroactive to January 2005, which was approved by the MPSC during the second quarter of fiscal 2005.

Atmos Energy West Texas Division. In September 2005, the West Texas Division made a GRIP filing to include in rate base approximately $22.6 million of distribution capital costs incurred during calendar year 2004, which should result in additional annual revenues of approximately $3.8 million. Of this amount, approximately $1.3 million related to our Lubbock jurisdiction and the remaining $2.5 million related to our West Texas jurisdiction. New charges for the filings were included in the monthly customer charge beginning May 2006. Atmos made its 2005 GRIP filings for the West Texas Division and the Lubbock Division in September 2006 requesting no change in rates.

In January 2006, the Lubbock, Texas City Council passed a resolution requiring us to submit copies of all documentation necessary for the city to review the rates of our West Texas Division to ensure they are just and reasonable. The requested information was provided to the city on February 28, 2006. We believe that we will be able to ultimately demonstrate to the City of Lubbock that our rates are just and reasonable.

In May 2006, we began receiving "show cause" ordinances from several of the cities in the West Texas Division. We made a filing in response to the ordinances on October 2, 2006. We believe that we will be able to ultimately demonstrate to the West Texas cities that our rates are just and reasonable.

In October 2003, our West Texas Division filed a rate case in Lubbock requesting a $3.0 million increase in annual revenues and WNA for our residential, commercial and public-authority customers. The City of Lubbock approved a $1.5 million increase effective March 2004, as well as the proposed WNA.

In September 2003, our West Texas Division filed a rate case in its West Texas System to request a $7.7 million increase in annual revenues and WNA for its residential, commercial and public-authority customers. In May 2004, the 66 cities in its West Texas System approved an increase of $3.2 million in our annual utility revenues. The cities also approved a WNA rider for residential, commercial, public-authority and state-institution customers. This rider became effective in October 2004.

Other Regulation

Each of our utility 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. 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. See Note 13 to our consolidated financial statements included in our annual report on Form 10-K for the year ended September 30, 2006, which is incorporated by reference in this prospectus supplement and the accompanying prospectus.

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.

Competition

Although our utility 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 and agricultural 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. However, higher gas prices, coupled with the electric utilities' marketing efforts, have increased competition for residential and commercial customers. In addition, our Natural Gas Marketing segment competes with other natural gas brokers in obtaining natural gas supplies for our customers.

Distribution, Transmission and Related Assets

At September 30, 2006, our utility segment owned an aggregate of 75,869 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. At September 30, 2006, our pipeline and storage segment owned 6,127 miles of gas transmission and gathering lines.

Our utility segment also holds franchises granted by the incorporated cities and towns that we serve. At September 30, 2006, we held 1,103 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.

Storage Assets

Our utility and pipeline and storage segments own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The underground gas storage facilities of our utility segment have a total usable capacity of 10,076,329 Mcf, with a maximum daily delivery capability of 242,100 Mcf. The underground gas storage facilities of our pipeline and storage segment have a total usable capacity of 43,059,958 Mcf, with a maximum daily delivery capability of 1,362,000 Mcf.

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. Our contracted storage provides us with a maximum storage quantity of 27,372,082 MMBtu, with a maximum daily withdrawal quantity of 776,415 MMBtu, for our utility segment other than our Mid-Tex Division and a maximum storage quantity of 10,786,846 MMBtu, with a maximum daily quantity of 297,675 MMBtu, for our natural gas marketing and our storage and pipeline segments. Maximum daily withdrawal amounts fluctuate depending upon the season and the month. The foregoing amounts represent maximum daily withdrawal quantities as of November 1, which is the beginning of the heating season.

For more information on our storage assets see "Item 2. Properties" in our annual report on Form 10-K for year ended September 30, 2006.

UNDERWRITING

Lehman Brothers Inc. and Goldman, Sachs & Co. are acting as joint book-running managers and representatives of the underwriters named below. Under the terms of an underwriting agreement, which we will file as an exhibit to our current report on Form 8-K and will be incorporated by reference in this prospectus supplement and the accompanying prospectus, each of the underwriters named below has severally agreed to purchase from us the respective number of common stock shown opposite its name below:

Underwriters	Number of Shares
Lehman Brothers Inc.	1,650,000
Goldman, Sachs & Co.	1,650,000
Banc of America Securities LLC	440,000
J.P. Morgan Securities Inc.	440,000
Merrill Lynch, Pierce, Fenner & Smith Incorporated	440,000
SunTrust Capital Markets, Inc.	440,000
Wachovia Capital Markets, LLC	440,000
Total	5,500,000

The underwriting agreement provides that the underwriters' obligation to purchase shares of common stock depends on the satisfaction of the conditions contained in the underwriting agreement including:

- the obligation to purchase all of the shares of common stock offered hereby (other than those shares of common stock covered by their option to purchase additional shares as described below), if any of the shares are purchased;
- the representations and warranties made by us to the underwriters are true;
- there is no material change in our business or in the financial markets; and
- we deliver customary closing documents to the underwriters.

Commissions and Expenses

The following table summarizes the underwriting discounts and commissions we will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional shares. The underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to us for the shares.

	No Exercise	Full Exercise
Per share	$ 1.1025	$ 1.1025
Total	$6,063,750	$6,973,313

The representatives of the underwriters have advised us that the underwriters propose to offer the shares of common stock directly to the public at the public offering price on the cover of this prospectus supplement and to selected dealers, which may include the underwriters, at such offering price less a selling concession not in excess of $0.6625 per share. After the offering, the representatives may change the offering price and other selling terms.

The expenses of the offering that are payable by us are estimated to be $400,000 (excluding underwriting discounts and commissions).

Option to Purchase Additional Shares

We have granted the underwriters an option exercisable for 30 days after the date of the underwriting agreement, to purchase, from time to time, in whole or in part, up to an aggregate of 825,000 shares at the public offering price less underwriting discounts and commissions. This option may be exercised if the underwriters sell more than 5,500,000 shares in connection with this offering. To the extent that this option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional shares based on the underwriter's percentage underwriting commitment in the offering as indicated in the table at the beginning of this Underwriting Section.

Lock-Up Agreements

We, all of our directors and executive officers have agreed that, subject to certain exceptions, without the prior written consent of each of Lehman Brothers Inc. and Goldman, Sachs & Co., for a period of 90 days commencing on the date of this prospectus supplement, we and they will not (1) directly or indirectly offer, pledge, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase or otherwise transfer or dispose of any shares of common stock or any securities convertible into or exercisable or exchangeable for common stock or file any registration statement under the Securities Act with respect to any of the foregoing or (2) enter into any swap or any other agreement or any transaction that transfers, in whole or in part, directly or indirectly, the economic consequence of ownership of the common stock, whether any such swap or transaction described in clause (1) or (2) above is to be settled by delivery of common stock or such other securities, in cash or otherwise.

The 90-day restricted period described in the preceding paragraph will be extended if:

- during the last 17 days of the 90-day restricted period, we issue an earnings release or material news or a material event relating to us occurs; or
- prior to the expiration of the 90-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 90-day period;

in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or the occurrence of a material event, unless such extension is waived in writing by Lehman Brothers Inc. and Goldman, Sachs & Co.

Lehman Brothers Inc. and Goldman, Sachs & Co., in their sole discretion, may release the common stock and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice. When determining whether or not to release common stock and other securities from lock-up agreements, Lehman Brothers Inc. and Goldman, Sachs & Co. will consider, among other factors, the holder's reasons for requesting the release, the number of shares of common stock and other securities for which the release is being requested and market conditions at the time.

Indemnification

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make for these liabilities.

Stabilization, Short Positions and Penalty Bids

The representatives may engage in stabilizing transactions, short sales and purchases to cover positions created by short sales, and penalty bids or purchases for the purpose of pegging, fixing or maintaining the price of the common stock, in accordance with Regulation M under the Securities Exchange Act of 1934:

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.
- A short position involves a sale by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase in the offering, which creates the syndicate short position. This short position may be either a covered short position or a naked short position. In a covered short position, the number of shares involved in the sales made by the underwriters in excess of the number of shares they are obligated to purchase is not greater than the number of shares that they may purchase by exercising their option to purchase additional shares. In a naked short position, the number of shares involved is greater than the number of shares in their option to purchase additional shares. The underwriters may close out any short position by either exercising their option to purchase additional shares and/or purchasing shares in the open market. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through their option to purchase additional shares. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.
- Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions.
- Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result, the price of the common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the New York Stock Exchange or otherwise and, if commenced, may be discontinued at any time.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common stock. In addition, neither we nor any of the underwriters make representation that the representatives will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

Electronic Distribution

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of shares for sale to online brokerage account holders. Any such allocation for online distributions will be made by the representatives on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter's or selling group member's web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus supplement and the accompanying prospectus forms a part, has not been approved and/or endorsed by us or

any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

Stamp Taxes

If you purchase shares of common stock offered in this prospectus supplement and the accompanying prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus supplement and the accompanying prospectus.

Relationships

Certain of the underwriters and their related entities have engaged and may engage in commercial and investment banking transactions with us in the ordinary course of their business. They have received customary compensation and expenses for these commercial and investment banking transactions.

Notice to Prospective Investors

European Economic Area. In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each a Relevant Member State), each underwriter has agreed that with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date) it has not made and will not make an offer of common stock to the public in that Relevant Member State prior to the publication of a prospectus in relation to the common stock which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of common stock to the public in that Relevant Member State at any time (a) to legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities; (b) to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than €43,000,000 and (3) an annual net turnover of more than €50,000,000, as shown in its last annual or consolidated accounts; or (c) in any other circumstances which do not require the publication by us of a prospectus pursuant to Article 3 of the Prospectus Directive. For the purposes of this provision, the expression an "offer of common stock to the public" in relation to any common stock in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the common stock to be offered so as to enable an investor to decide to purchase the common stock, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

United Kingdom. Each underwriter agrees that (i) it is a person whose ordinary activities involve it in acquiring, holding, managing or disposing of investments (as principal or agent) for the purposes of its business and (ii) it has not offered or sold and will not offer or sell the common stock other than to persons whose ordinary activities involve them in acquiring, holding, managing or disposing of investments (as principal or as agent) for the purposes of their businesses or who it is reasonable to expect will acquire, hold, manage or dispose of investments (as principal or agent) for the purposes of their businesses where the issue of the common stock would otherwise constitute a contravention of Section 19 of the Financial Services and Markets Act 2000 (FSMA) by us; (iii) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the FSMA) received by it in connection with the issue or sale of the common stock in circumstances in which Section 21(1) of the FSMA does not apply to us; and (iv) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the common stock in, from or otherwise involving the United Kingdom.

Hong Kong. The common stock may not be offered or sold by means of any document other than to persons whose ordinary business is to buy or sell shares or debentures, whether as principal or agent, or in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap. 32) of Hong Kong, and no advertisement, invitation or document relating to the common stock may be issued, whether in Hong Kong or elsewhere, which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than with respect to common stock which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571) of Hong Kong and any rules made thereunder.

Japan. The common stock has not been and will not be registered under the Securities and Exchange Law of Japan (the Securities and Exchange Law) and each underwriter has agreed that it will not offer or sell any securities, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Securities and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

Singapore. This prospectus supplement and the accompanying prospectus have not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus supplement and the accompanying prospectus and any other document or material in connection with the offer or sale, or invitation for purchase, of the common stock may not be circulated or distributed, nor may the common stock be offered or sold, or be made the subject of an invitation for purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (SFA), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA. Where the common stock is purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for six months after that corporation or that trust has acquired the common stock under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

LEGAL MATTERS

Gibson, Dunn & Crutcher LLP, Dallas, Texas, and Hunton & Williams LLP, Richmond, Virginia, will opine for us as to the validity of the offered shares. Shearman & Sterling LLP, New York, New York, will pass upon certain legal matters related to the offered shares for the underwriters.

EXPERTS

The consolidated financial statements of Atmos Energy Corporation appearing in Atmos Energy Corporation's Annual Report (Form 10-K) for the year ended September 30, 2006 and Atmos Energy Corporation management's assessment of the effectiveness of internal control over financial reporting as of September 30, 2006 included therein have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their reports thereon included therein, and incorporated herein by reference. Such consolidated financial statements and management's assessment have been incorporated herein by reference in reliance upon such reports given on the authority of such firm as experts in accounting and auditing.

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PROSPECTUS

Atmos Energy Corporation

By this prospectus, we offer up to

$900,000,000

of debt securities and common stock.

We will provide specific terms of these securities in supplements to this prospectus. This prospectus may not be used to sell securities unless accompanied by a prospectus supplement. You should read this prospectus and the applicable prospectus supplement carefully before you invest.

Investing in these securities involves risks that are described in the "Risk Factors" section beginning on page 1 of this prospectus.

Our common stock is listed on the New York Stock Exchange under the symbol "ATO."

Our address is 1800 Three Lincoln Centre, 5430 LBJ Freeway, Dallas, Texas 75240, and our telephone number is (972) 934-9227.

The Securities and Exchange Commission and state securities regulators have not approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

This prospectus is dated December 4, 2006

We have not authorized any other person to provide you with any information or to make any representations that is different from, or in addition to, the information and representations contained in this prospectus or in any of the documents that are incorporated by reference in this prospectus. If anyone provides you with different or inconsistent information, you should not rely on it. You should assume that the information appearing in this prospectus, as well as the information contained in any document incorporated by reference, is accurate as of the date of each such document only, unless the information specifically indicates that another date applies.

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The distribution of this prospectus may be restricted by law in certain jurisdictions. You should inform yourself about and observe any of these restrictions. This prospectus does not constitute, and may not be used in connection with, an offer or solicitation by anyone in any jurisdiction in which the offer or solicitation is not authorized, or in which the person making the offer or solicitation is not qualified to do so, or to any person to whom it is unlawful to make the offer or solicitation.

The terms "we," "our," "us" and "Atmos" refer to Atmos Energy Corporation and its subsidiaries unless the context suggests otherwise. The term "you" refers to a prospective investor.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Statements contained or incorporated by reference in this prospectus that are not statements of historical fact are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933. Forward-looking statements are based on management's beliefs as well as assumptions made by, and information currently available to, management. Because such statements are based on expectations as to future results and are not statements of fact, actual results may differ materially from those stated. Important factors that could cause future results to differ include, but are not limited to:

- regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions;
- adverse weather conditions, such as warmer-than-normal weather in our utility service territories or colder-than-normal weather that could adversely affect our natural gas marketing activities;
- the concentration of our distribution, pipeline and storage operations in one state;
- impact of environmental regulations on our business;
- market risks beyond our control affecting our risk management activities, including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness;
- our ability to continue to access the capital markets;
- effects of inflation;
- effects of changes in the availability and prices of natural gas, including the volatility of natural gas prices;
- increased competition from other energy suppliers and alternative forms of energy;
- increased costs of providing pension and post-retirement health care benefits;
- the capital-intensive nature of our distribution business;
- the inherent hazards and risks involved in operating a distribution business;
- effects of natural disasters or terrorist activities; and
- other factors discussed in this prospectus and our other filings with the SEC.

All of these factors are difficult to predict and many 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. When used in 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. We undertake no obligation to update or revise our forward-looking statements, whether as a result of new information, future events or otherwise.

For factors you should consider, please refer to "Risk Factors" beginning on page 1 of this prospectus and "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our annual report on Form 10-K for the year ended September 30, 2006 and the other documents incorporated herein by reference, as well as any applicable prospectus supplements.

RISK FACTORS

You should consider carefully all of the information that is included or incorporated by reference in this prospectus before investing in our debt securities or our common stock. In particular, you should evaluate the uncertainties and risks referred to or described below, which may adversely affect our business, financial condition or results of operations. Additional uncertainties and risks that are not presently known to us or that we currently deem immaterial may also adversely affect our business, financial condition or results of operations. Additional risk factors may be included in a prospectus supplement relating to a particular offering of securities.

We are subject to regulation by each state in which we operate that affect our operations and financial results.

Our natural gas utility business is subject to various regulated returns on its rate base in each of the 12 states 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 are needed. In addition, in the normal course of the regulatory environment, assets may be placed in service and historical test periods established before rate cases that could adjust our returns can be filed. 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". In addition, rate cases involve a risk of rate reduction, and once rates have been approved, they are still subject to challenge for their reasonableness by appropriate regulatory authorities. Our debt and equity financings are also subject to approval by regulatory bodies in several states which could limit our ability to take advantage of favorable market conditions.

Our business could also be affected by deregulation initiatives, including the development of unbundling initiatives in the natural gas industry. Unbundling is the separation of the provision and pricing of local distribution gas services into discrete components. It typically focuses on the separation of the distribution and gas supply components and the resulting opening of the regulated components of sales services to alternative unregulated suppliers of those services. Although we believe that our enhanced technology and distribution system infrastructures have positively positioned us, we cannot provide assurance that there would be no significant adverse effect on our business should unbundling or further deregulation of the natural gas distribution service business occur.

Our operations are weather sensitive.

Our natural gas utility sales volumes and related revenues are correlated with heating requirements that result from cold winter weather. Although beginning in the 2006-2007 winter heating season, we will have weather-normalized rates for over 90 percent of our residential and commercial meters that should substantially eliminate the adverse effects of warmer-than-normal weather for meters in those service areas, our utility operating results will continue to vary with the temperatures during the winter heating season. In addition, sustained cold weather could adversely affect our natural gas marketing 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.

The concentration of our distribution, pipeline and storage operations in the State of Texas has increased the exposure of our operations and financial results to adverse weather, economic conditions or regulatory decisions in Texas.

As a result of our acquisition of the distribution, pipeline and storage operations of TXU Gas in October 2004, over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are now located in the State of Texas. This concentration of our business in Texas means that our operations and financial results are subject to greater impact than before from changes in the Texas economy in general as well as the weather in our service areas of the state during the winter heating season. Our financial results in fiscal 2006 were adversely affected by warm weather in Texas. In addition, the impact of any adverse rate or other regulatory decisions by state or local regulatory authorities in Texas will also be greater. The hearing in the Mid-Tex Division's first rate case since the TXU Gas acquisition has just concluded. In the proceeding, we are seeking additional revenue and several rate design changes. A rate reduction or other significant, adverse decision by the Texas Railroad Commission in the proceeding could materially affect our financial results.

We are subject to environmental regulation 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. Such revised or new regulations could result in increased compliance costs or additional operating restrictions which could adversely affect our business, financial condition and results of operations.

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

Our risk management operations are subject to market risks beyond our control including market liquidity, commodity price volatility 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 or the risk in our natural gas marketing and pipeline and storage segments which could lead to volatility in our earnings. Physical trading 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. 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. The determination of our net open position as of any 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 each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. 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 because the timing of the recognition of profits or losses on the hedges for financial accounting purposes does not always match up with 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. Further, if the local physical markets in which we trade do not move consistently with the New York Mercantile Exchange (NYMEX) futures market, we could experience increased volatility in the financial results of our natural gas marketing and pipeline and storage segments.

Our natural gas marketing and pipeline and storage segments manage margins and limit 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 derivatives. 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. 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.

We are also subject to interest rate risk on our commercial paper borrowings and floating rate debt. In the past few years, we have been operating in a relatively low interest-rate environment with both short and long-term interest rates being relatively low compared to past interest rates. However, in the past two years, the Federal Reserve has taken actions that have resulted in increases in short-term interest rates. Future increases in interest rates could adversely affect our future financial results.

The execution of our business plan could be affected by an inability to access financial markets.

We rely upon access to both short-term and long-term capital markets to satisfy our liquidity requirements. Adverse changes in the economy or these markets, the overall health of the industries in which we operate and changes to our credit ratings could limit access to these markets, increase our cost of capital or restrict the execution of our business plan.

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation, Moody's Investors Services, Inc. and Fitch Ratings, Ltd., the three credit rating agencies that rate our long-term debt securities. There can be no assurance that these rating agencies will maintain investment grade ratings for our long-term debt. If we were to lose our investment-grade rating, the commercial paper markets and the commodity derivatives markets could become unavailable to us. This would increase our borrowing costs for working capital and reduce the borrowing capacity of our gas marketing affiliate. If our commercial paper ratings were lowered, it would also increase the cost of commercial paper financing and could reduce or eliminate our ability to access the commercial paper markets. If we are unable to issue commercial paper, we intend to borrow under our bank credit facilities to meet our working capital needs. This would increase the cost of our working capital financing. In addition, one of our regulatory approvals for the offer and sale of debt securities covered by the registration statement of which this prospectus is a part is conditioned upon our continued investment grade rating from at least one of the credit rating agencies named above.

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 utility 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 influence future results.

Rapid increases in the price of purchased gas, which occurred recently and in some prior years, cause us to experience a significant increase in short-term debt because 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 utility 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 operations are subject to increased competition.

In the residential and commercial customer markets, our regulated utility 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, resulting in reduced 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, and agricultural customers, 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 pipeline and storage operations currently face limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, competition may increase if new intrastate pipelines are constructed near our existing facilities.

The cost of providing pension and postretirement health care benefits is subject to changes in pension fund values and changing demographics and may have a material adverse effect on our financial results.

We provide a cash-balance pension plan for the benefit of eligible full-time employees as well as postretirement health care benefits to eligible full-time employees. Our costs of providing such benefits is subject to changes in the market value of our pension fund assets, 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, and various actuarial calculations and assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates and other factors. These differences may result in a significant impact on the amount of pension expense or other postretirement benefit costs recorded in future periods.

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 maintain the 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. Our cash flows from operations are generally not sufficient to supply funding for all our capital expenditures including the financing of the costs of this new construction along with capital expenditures necessary to maintain our existing natural gas system. As a result, we must fund at least a portion of these costs through borrowing funds from third party lenders, the cost of which is dependent on the interest rates at the time. 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.

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 financial position and results of operations could be adversely affected.

Natural disasters and terrorist activities and other actions 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 future financial results.

ATMOS ENERGY CORPORATION

Atmos Energy Corporation and its subsidiaries are engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. We are one of the country's largest natural-gas-only distributors based on number of customers and one of the largest intrastate pipeline operators in Texas based upon miles of pipe. As of September 30, 2006, we distributed natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our seven regulated utility divisions, which covered service areas in 12 states. 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. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to some of our utility divisions and to third parties.

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services, and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

Our overall strategy is to:

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

Over the last five years, we have primarily grown through two significant acquisitions, our acquisition in December 2002 of Mississippi Valley Gas Company (MVG) and our acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas).

We have experienced over 20 consecutive years of increasing dividends and earnings growth after giving effect to our acquisitions. We have achieved this record of growth while operating our utility operations efficiently by managing our operating and maintenance expenses and leveraging our technology, such as our 24-hour call centers, to achieve more efficient operations. In addition, we have focused on regulatory rate proceedings to increase revenue as our costs increase and mitigated weather-related risks through weather-normalized rates that now apply to most of our service areas. We have also strengthened our nonutility businesses by increasing gross profit margins, actively pursuing opportunities to increase the amount of storage available to us and expanding commercial opportunities in our pipeline and storage segment.

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.

SECURITIES WE MAY OFFER

Types of Securities

The types of securities that we may offer and sell from time to time by this prospectus are:

- debt securities, which we may issue in one or more series; and
- common stock.

The aggregate initial offering price of all securities sold will not exceed $900,000,000. We will determine when we sell securities, the amounts of securities we will sell and the prices and other terms on which we will sell them. We may sell securities to or through underwriters, through agents or dealers or directly to purchasers. The offer and sale of securities by this prospectus is subject to receipt of satisfactory regulatory approvals in five states, all of which have been received.

Prospectus Supplements

This prospectus provides you with a general description of the debt securities and common stock we may offer. Each time we offer securities, we will provide a prospectus supplement that will contain specific information about the terms of the offering. The prospectus supplement may also add to or change information contained in this prospectus. In that case, the prospectus supplement should be read as superseding this prospectus.

In each prospectus supplement, which will be attached to the front of this prospectus, we will include, among other things, the following information:

- the type and amount of securities which we propose to sell;
- the initial public offering price of the securities;
- the names of the underwriters, agents or dealers, if any, through or to which we will sell the securities;
- the compensation, if any, of those underwriters, agents or dealers;
- if applicable, information about the securities exchanges or automated quotation systems on which the securities will be listed or traded;
- material United States federal income tax considerations applicable to the securities, where necessary; and
- any other material information about the offering and sale of the securities.

For more details on the terms of the securities, you should read the exhibits filed with our registration statement, of which this prospectus is a part. You should also read both this prospectus and any prospectus supplement, together with additional information described under the heading "Where You Can Find More Information."

USE OF PROCEEDS

Except as may otherwise be stated in the applicable prospectus supplement, we intend to use the net proceeds from the sale of the securities that we may offer and sell from time to time by this prospectus for general corporate purposes, including for working capital, repaying indebtedness and funding capital projects, acquisitions and other growth.

RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratio of earnings to fixed charges for the periods indicated:

	Year Ended September 30,				
	2006	2005	2004	2003	2002
Ratio	2.50	2.54	2.95	2.85	2.46

For purposes of computing the ratio of earnings to fixed charges, earnings consists of the sum of our income from continuing operations, before income taxes and cumulative effect of accounting changes, and fixed charges. Fixed charges consist of interest expense, amortization of debt discount, premium and expense, capitalized interest and a portion of lease payments considered to represent an interest factor.

DESCRIPTION OF DEBT SECURITIES

We may issue debt securities from time to time in one or more distinct series. This section summarizes the material terms of any debt securities that we anticipate will be common to all series. Please note that the terms of any series of debt securities that we may offer may differ significantly from the common terms described in this prospectus. Most of the specific terms of any series of debt securities that we offer, and any differences from the common terms described in this prospectus, will be described in the prospectus supplement for such securities to be attached to the front of this prospectus.

As required by U.S. federal law for all bonds and notes of companies that are publicly offered, a document called an "indenture" will govern any debt securities that we issue. An indenture is a contract between us and a financial institution acting as trustee on your behalf. We will enter into an indenture with an institution having corporate trust powers, which will act as trustee, relating to any debt securities that are offered by this prospectus. The indenture will be subject to the Trust Indenture Act of 1939. The trustee under an indenture has the following two main roles:

- the trustee can enforce your rights against us if we default; there are some limitations on the extent to which the trustee acts on your behalf, which are described later in this prospectus; and
- the trustee will perform certain administrative duties for us, which include sending you interest payments and notices.

As this section is a summary of some of the terms of the debt securities we may offer under this prospectus, it does not describe every aspect of the debt securities. We urge you to read the indenture and the other documents we file with the SEC relating to the debt securities because the indenture for those securities and those other documents, and not this description, will define your rights as a holder of our debt securities. We have filed the indenture as an exhibit to the registration statement that we have filed with the SEC, and we will file any such other documents as exhibits to an annual, quarterly or other report that we file with the SEC. See "Where You Can Find More Information," for information on how to obtain copies of the indenture and any such other documents. References to the "indenture" mean the indenture that will define your rights as a holder of debt securities, a form of which we have filed as an exhibit to the registration statement of which this prospectus forms a part. The actual indenture we enter into in connection with an offering of debt securities may differ significantly from the form of indenture we have filed.

General

The debt securities will be our unsecured obligations. Senior debt securities will rank equally with all of our other unsecured and unsubordinated Indebtedness. Subordinated debt securities will rank junior to our senior indebtedness, including our credit facilities.

You should read the prospectus supplement for the following terms of the series of debt securities offered by the prospectus supplement. Our board of directors will establish the following terms before issuance of the series:

- the title of the debt securities and whether the debt securities will be senior debt securities or subordinated debt securities;
- the ranking of the debt securities;
- if the debt securities are subordinated, the terms of subordination;
- the aggregate principal amount of the debt securities, the percentage of their principal amount at which the debt securities will be issued, and the date or dates when the principal of the debt securities will be payable or how those dates will be determined or extended;
- the interest rate or rates, which may be fixed or variable, that the debt securities will bear, if any, how the rate or rates will be determined, and the periods when the rate or rates will be in effect;
- the date or dates from which any interest will accrue or how the date or dates will be determined, the date or dates on which any interest will be payable, whether and the terms under which payment of interest may be deferred, any regular record dates for these payments or how these dates will be determined and the basis on which any interest will be calculated, if other than on the basis of a 360-day year of twelve 30-day months;
- the place or places, if any, other than or in addition to New York City, of payment, transfer or exchange of the debt securities, and where notices or demands to or upon us in respect of the debt securities may be served;
- any optional redemption provisions and any restrictions on the sources of funds for redemption payments, which may benefit the holders of other securities;
- any sinking fund or other provisions that would obligate us to repurchase or redeem the debt securities;
- whether the amount of payments of principal of, any premium on, or interest on the debt securities will be determined with reference to an index, formula or other method, which could be based on one or more commodities, equity indices or other indices, and how these amounts will be determined;
- any covenants with respect to the debt securities and any changes or additions to the events of default described in this prospectus;
- if not the principal amount of the debt securities, the portion of the principal amount that will be payable upon acceleration of the maturity of the debt securities or how that portion will be determined;
- any changes or additions to the provisions concerning defeasance and covenant defeasance contained in the applicable indenture that will be applicable to the debt securities;
- any provisions granting special rights to the holders of the debt securities upon the occurrence of specified events;
- if other than the trustee, the name of the paying agent, security registrar or transfer agent for the debt securities;
- if we do not issue the debt securities in book-entry form only to be held by The Depository Trust Company, as depository, whether we will issue the debt securities in certificated form or the identity of any alternative depository;
- the person to whom any interest in a debt security will be payable, if other than the registered holder at the close of business on the regular record date;
- the denomination or denominations in which the debt securities will be issued, if other than denominations of $1,000 or any integral multiples;

- any provisions requiring us to pay additional amounts on the debt securities to any holder who is not a United States person in respect of any tax, assessment or governmental charge and, if so, whether we will have the option to redeem the debt securities rather than pay the additional amounts; and
- any other material terms of the debt securities or the indenture, which may not be consistent with the terms set forth in this prospectus.

For purposes of this prospectus, any reference to the payment of principal of, any premium on, or interest on the debt securities will include additional amounts if required by the terms of the debt securities.

The indenture will not limit the amount of debt securities that we are authorized to issue from time to time. The indenture will also provide that there may be more than one trustee thereunder, each for one or more series of debt securities. If a trustee is acting under the indenture with respect to more than one series of debt securities, the debt securities for which it is acting would be treated as if issued under separate indentures. If there is more than one trustee under the indenture, the powers and trust obligations of each trustee will apply only to the debt securities of the separate series for which it is trustee.

We may issue debt securities with terms different from those of debt securities already issued. Without the consent of the holders of the outstanding debt securities, we may reopen a previous issue of a series of debt securities and issue additional debt securities of that series unless the reopening was restricted when we created that series.

There is no requirement that we issue debt securities in the future under the indenture, and we may use other indentures or documentation, containing different provisions in connection with future issues of other debt securities.

We may issue the debt securities as "original issue discount securities," which are debt securities, including any zero-coupon debt securities, that are issued and sold at a discount from their stated principal amount. Original issue discount securities provide that, upon acceleration of their maturity, an amount less than their principal amount will become due and payable. We will describe the U.S. federal income tax consequences and other considerations applicable to original issue discount securities in any prospectus supplement relating to them.

Holders of Debt Securities

Book-Entry Holders. We will issue debt securities in book-entry form only, unless we specify otherwise in the applicable prospectus supplement. This means the debt securities will be represented by one or more global securities registered in the name of a financial institution that holds them as depository on behalf of other financial institutions that participate in the depository's book-entry system. These participating institutions, in turn, hold beneficial interests in the debt securities on behalf of themselves or their customers.

Under the indenture, we will recognize as a holder only the person in whose name a debt security is registered. Consequently, for debt securities issued in global form, we will recognize only the depository as the holder of the debt securities and we will make all payments on the debt securities to the depository. The depository passes along the payments it receives to its participants, which in turn pass the payments along to their customers who are the beneficial owners.

The depository and its participants do so under agreements they have made with one another or with their customers; they are not obligated to do so under the terms of the debt securities.

As a result, you will not own the debt securities directly. Instead, you will own beneficial interests in a global security, through a bank, broker or other financial institution that participates in the depository's book-entry system or holds an interest through a participant. As long as the debt securities are issued in global form, you will be an indirect holder, and not a holder, of the debt securities.

Street Name Holders. In the future we may terminate a global security or issue debt securities initially in non-global form. In these cases, you may choose to hold your debt securities in your own name or in "street name." Debt securities held in street name would be registered in the name of a bank, broker or other financial institution that you choose, and you would hold only a beneficial interest in those debt securities through an account you maintain at that institution.

For debt securities held in street name, we will recognize only the intermediary banks, brokers and other financial institutions in whose names the debt securities are registered as the holders of those debt securities, and we will make all payments on those debt securities to them. These institutions pass along the payments they receive to their customers who are the beneficial owners, but only because they agree to do so in their customer agreements or because they are legally required to do so. If you hold debt securities in street name you will be an indirect holder, and not a holder, of those debt securities.

Legal Holders. Our obligations, as well as the obligations of the trustee and those of any third parties employed by us or the trustee, run only to the legal holders of the debt securities. We do not have obligations to you if you hold beneficial interests in global securities, in street name or by any other indirect means. This will be the case whether you choose to be an indirect holder of a debt security or have no choice because we are issuing the debt securities only in global form.

For example, once we make a payment or give a notice to the holder, we have no further responsibility for the payment or notice even if that holder is required, under agreements with depository participants or customers or by law, to pass it along to the indirect holders but does not do so. Similarly, if we want to obtain the approval of the holders for any purpose (for example, to amend the indenture or to relieve us of the consequences of a default or of our obligation to comply with a particular provision of the indenture) we would seek the approval only from the holders, and not the indirect holders, of the debt securities. Whether and how the holders contact the indirect holders is up to the holders.

When we refer to you, we mean those who invest in the debt securities being offered by this prospectus, whether they are the holders or only indirect holders of those debt securities. When we refer to your debt securities, we mean the debt securities in which you hold a direct or indirect interest.

Special Considerations for Indirect Holders. If you hold debt securities through a bank, broker or other financial institution, either in book-entry form or in street name, you should check with your own institution to find out:

- how it handles securities payments and notices;
- whether it imposes fees or charges;
- how it would handle a request for the holders' consent, if ever required;
- whether and how you can instruct it to send you debt securities registered in your own name so you can be a holder, if that is permitted in the future;
- how it would exercise rights under the debt securities if there were a default or other event triggering the need for holders to act to protect their interests; and
- if the debt securities are in book-entry form, how the depository's rules and procedures will affect these matters.

Global Securities

What is a Global Security? We will issue each debt security under the indenture in book-entry form only, unless we specify otherwise in the applicable prospectus supplement. A global security represents one or any other number of individual debt securities. Generally, all debt securities represented by the same global securities will have the same terms. We may, however, issue a global security that represents multiple debt securities that have different terms and are issued at different times. We call this kind of global security a master global security.

Each debt security issued in book-entry form will be represented by a global security that we deposit with and register in the name of a financial institution or its nominee that we select. The financial institution that we select for this purpose is called the depository. Unless we specify otherwise in the applicable

prospectus supplement, The Depository Trust Company, New York, New York, known as DTC, will be the depository for all debt securities issued in book-entry form.

A global security may not be transferred to or registered in the name of anyone other than the depository or its nominee, unless special termination situations arise. We describe those situations below under "Special Situations When a Global Security Will Be Terminated." As a result of these arrangements, the depository, or its nominee, will be the sole registered owner and holder of all debt securities represented by a global security, and investors will be permitted to own only beneficial interests in a global security. Beneficial interests must be held by means of an account with a broker, bank or other financial institution that in turn has an account with the depository or with another institution that does. Thus, if your security is represented by a global security, you will not be a holder of the debt security, but only an indirect holder of a beneficial interest in the global security.

Special Considerations for Global Securities. We do not recognize an indirect holder as a holder of debt securities and instead deal only with the depository that holds the global security. The account rules of your financial institution and of the depository, as well as general laws relating to securities transfers, will govern your rights relating to a global security.

If we issue debt securities only in the form of a global security, you should be aware of the following:

- you cannot cause the debt securities to be registered in your name, and cannot obtain non-global certificates for your interest in the debt securities, except in the special situations that we describe below;
- you will be an indirect holder and must look to your own bank or broker for payments on the debt securities and protection of your legal rights relating to the debt securities, as we describe under "Holders of Debt Securities" above;
- you may not be able to sell interests in the debt securities to some insurance companies and to other institutions that are required by law to own their securities in non-book-entry form;
- you may not be able to pledge your interest in a global security in circumstances where certificates representing the debt securities must be delivered to the lender or other beneficiary of the pledge in order for the pledge to be effective;
- the depository's policies, which may change from time to time, will govern payments, transfers, exchanges and other matters relating to your interest in a global security. We and the trustee have no responsibility for any aspect of the depository's actions or for its records of ownership interests in a global security. We and the trustee also do not supervise the depository in any way;
- DTC requires, and other depositories may require, that those who purchase and sell interests in a global security within its book-entry system use immediately available funds and your broker or bank may require you to do so as well; and
- financial institutions that participate in the depository's book-entry system, and through which you hold your interest in a global security, may also have their own policies affecting payments, notices and other matters relating to the debt security. Your chain of ownership may contain more than one financial intermediary. We do not monitor and are not responsible for the actions of any of those intermediaries.

Special Situations When a Global Security Will Be Terminated. In a few special situations described below, a global security will be terminated and interests in it will be exchanged for certificates in non-global form representing the debt securities it represented. After that exchange, you will be able to choose whether to hold the debt securities directly or in street name. You must consult your own bank or broker to find out how to have your interests in a global security transferred on termination to your own name, so that you will be a holder. We have described the rights of holders and street name investors above under "Holders of Debt Securities."

The special situations for termination of a global security are as follows:

- if the depository notifies us that it is unwilling, unable or no longer qualified to continue as depository for that global security and we do not appoint another institution to act as depository within 60 days;
- if we notify the trustee that we wish to terminate that global security; or
- if an event of default has occurred with regard to debt securities represented by that global security and has not been cured or waived; we discuss defaults later under "Events of Default."

If a global security is terminated, only the depository, and not we or the trustee, is responsible for deciding the names of the intermediary banks, brokers and other financial institutions in whose names the debt securities represented by the global security are registered, and, therefore, who will be the holders of those debt securities.

Covenants

Please refer to the prospectus supplement for information about the covenants that will be applicable to the debt securities offered thereby.

Modification or Waiver

There are two types of changes that we can make to the indenture and the debt securities.

Changes Requiring Approval. With the approval of the holders of at least a majority in principal amount of all outstanding debt securities of each series affected (including any such approvals obtained in connection with a tender or exchange offer for outstanding debt securities), we may make any changes, additions or deletions to any provisions of the indenture applicable to the affected series, or modify the rights of the holders of the debt securities of the affected series. However, without the consent of each holder affected, we cannot:

- change the stated maturity of the principal of, any premium on, or the interest on a debt security;
- change any of our obligations to pay additional amounts;
- reduce the amount payable upon acceleration of maturity following the default of a debt security whose principal amount payable at stated maturity may be more or less than its principal face amount at original issuance or an original issue discount security;
- adversely affect any right of repayment at the holder's option;
- change the place of payment of a debt security;
- impair the holder's right to sue for payment;
- adversely affect any right to convert or exchange a debt security;
- reduce the percentage of holders of debt securities whose consent is needed to modify or amend the indenture;
- reduce the percentage of holders of debt securities whose consent is needed to waive compliance with any provisions of the indenture or to waive any defaults; or
- modify any of the provisions of the indenture dealing with modification and waiver in any other respect, except to increase any percentage of consents required to amend the indenture or for any waiver or to add to the provisions that cannot be modified without the approval of each affected holder.

Changes Not Requiring Approval. The second type of change does not require any vote by the holders of the debt securities. This type is limited to clarifications and certain other changes that would not adversely affect holders of the outstanding debt securities in any material respect. Nor do we need any approval to make any change that affects only debt securities to be issued under the indenture after the changes take effect.

Further Details Concerning Voting. When taking a vote, we will use the following rules to decide how much principal amount to attribute to a debt security:

- for original issue discount securities, we will use the principal amount that would be due and payable on the voting date if the maturity of the debt securities were accelerated to that date because of a default; and
- for debt securities whose principal amount is not known (for example, because it is based on an index) we will use a special rule for that debt security described in the prospectus supplement.

Debt securities will not be considered outstanding, and therefore not eligible to vote, if we have deposited or set aside in trust money for their payment or redemption. Debt securities will also not be eligible to vote if they have been fully defeased as described later under "Defeasance and Covenant Defeasance."

Book-entry and other indirect holders should consult their banks or brokers for information on how approval may be granted or denied if we seek to change the indenture or the debt securities or request a waiver.

Events of Default

Holders of debt securities will have special rights if an Event of Default occurs as to the debt securities of their series that is not cured, as described later in this subsection. Please refer to the prospectus supplement for information about any changes to the Events of Default, including any addition of a provision providing event risk or similar protection.

What is an Event of Default? The term "Event of Default" as to the debt securities of a series means any of the following:

- we do not pay interest on a debt security of the series within 30 days of its due date;
- we do not pay the principal of or any premium, if any, on a debt security of the series on its due date;
- we do not deposit any sinking fund payment when and as due by the terms of any debt securities requiring such payment;
- we remain in breach of a covenant or agreement in the indenture, other than a covenant or agreement for the benefit of less than all of the holders of the debt securities, for 60 days after we receive written notice stating that we are in breach from the trustee or the holders of at least 25 percent of the principal amount of the debt securities of the series;
- we or a restricted subsidiary of ours is in default under any matured or accelerated agreement or instrument under which we have outstanding Indebtedness for borrowed money or guarantees, which individually is in excess of $25,000,000, and we have not cured any acceleration within 30 days after we receive notice of this default from the trustee or the holders of at least 25 percent of the principal amount of the debt securities of the series, unless prior to the entry of judgment for the trustee, we or the restricted subsidiary remedy the default or the default is waived by the holders of the indebtedness;
- we file for bankruptcy or other events of bankruptcy, insolvency or reorganization occur; or
- any other Event of Default provided for the benefit of debt securities of the series.

An Event of Default for a particular series of debt securities will not necessarily constitute an Event of Default for any other series of debt securities issued under the indenture.

The trustee may withhold notice to the holders of debt securities of a particular series of any default if it considers its withholding of notice to be in the interest of the holders of that series, except that the trustee may not withhold notice of a default in the payment of the principal of, any premium on, or the interest on the debt securities.

Remedies if an Event of Default Occurs. If an event of default has occurred and is continuing, the trustee or the holders of at least 25 percent in principal amount of the debt securities of the affected series

may declare the entire principal amount of all the debt securities of that series to be due and immediately payable by notifying us, and the trustee, if the holders give notice, in writing. This is called a declaration of acceleration of maturity.

If the maturity of any series of debt securities is accelerated and a judgment for payment has not yet been obtained, the holders of a majority in principal amount of the debt securities of that series may cancel the acceleration if all events of default other than the non-payment of principal or interest on the debt securities of that series that have become due solely by a declaration of acceleration are cured or waived, and we deposit with the trustee a sufficient sum of money to pay:

- all overdue interest on outstanding debt securities of that series;
- all unpaid principal of any outstanding debt securities of that series that has become due otherwise than by a declaration of acceleration, and interest on the unpaid principal;
- all interest on the overdue interest; and
- all amounts paid or advanced by the trustee for that series and reasonable compensation of the trustee.

Except in cases of default, where the trustee has some special duties, the trustee is not required to take any action under the indenture at the request of any holders unless the holders offer the trustee reasonable protection from expenses and liability. This is called an indemnity. If reasonable indemnity is provided, the holders of a majority in principal amount of the outstanding debt securities of the relevant series may direct the time, method and place of conducting any lawsuit or other formal legal action seeking any remedy available to the trustee. The trustee may refuse to follow those directions if the directions conflict with any law or the indenture or expose the trustee to personal liability. No delay or omission in exercising any right or remedy will be treated as a waiver of that right, remedy or Event of Default.

Before a holder is allowed to bypass the trustee and bring his or her own lawsuit or other formal legal action or take other steps to enforce his or her rights or protect his or her interest relating to the debt securities, the following must occur:

- the holder must give the trustee written notice that an Event of Default has occurred and remains uncured;
- the holders of at least 25 percent in principal amount of all outstanding debt securities of the relevant series must make a written request that the trustee take action because of the default and must offer reasonable indemnity to the trustee against the cost and other liabilities of taking that action;
- the trustee must not have instituted a proceeding for 60 days after receipt of the above notice and offer of indemnity; and
- the holders of a majority in principal amount of the debt securities must not have given the trustee a direction inconsistent with the above notice during the 60-day period.

However, a holder is entitled at any time to bring a lawsuit for the payment of money due on his or her debt securities on or after the due date without complying with the foregoing.

Holders of a majority in principal amount of the debt securities of the affected series may waive any past defaults other than the following:

- the payment of principal, any premium, interest or additional amounts on any debt security; or
- in respect of a covenant that under the indenture cannot be modified or amended without the consent of each holder affected.

Each year, we will furnish the trustee with a written statement of two of our officers certifying that, to their knowledge, we are in compliance with the indenture and the debt securities, or else specifying any default.

Book-entry and other indirect holders should consult their banks or brokers for information on how to give notice or direction to or make a request of the trustee and how to declare or cancel an acceleration.

Defeasance and Covenant Defeasance

Unless we provide otherwise in the applicable prospectus supplement, the provisions for full defeasance and covenant defeasance described below apply to each series of debt securities. In general, we expect these provisions to apply to each debt security that is not a floating rate or indexed debt security.

Full Defeasance. If there is a change in U.S. federal tax law, as described below, we can legally release ourselves from all payment and other obligations on the debt securities, called "full defeasance," if we put in place the following arrangements for you to be repaid:

- we must deposit in trust for the benefit of all holders of the debt securities a combination of money and obligations issued or guaranteed by the U.S. government that will generate enough cash to make interest, principal and any other payments on the debt securities on their various due dates; and
- we must deliver to the trustee a legal opinion confirming that there has been a change in current federal tax law or an IRS ruling that lets us make the above deposit without causing you to be taxed on the debt securities any differently than if we did not make the deposit and just repaid the debt securities ourselves at maturity. Under current federal tax law, the deposit and our legal release from the debt securities would be treated as though we paid you your share of the cash and notes or bonds at the time the cash and notes or bonds are deposited in trust in exchange for your debt securities, and you would recognize gain or loss on the debt securities at the time of the deposit.

If we ever did accomplish defeasance, as described above, you would have to rely solely on the trust deposit for repayment of the debt securities. You could not look to us for repayment in the event of any shortfall. Conversely, the trust deposit would most likely be protected from claims of our lenders and other creditors if we ever become bankrupt or insolvent. If we accomplish a defeasance, we would retain only the obligations to register the transfer or exchange of the debt securities, to maintain an office or agency in respect of the debt securities and to hold moneys for payment in trust.

Covenant Defeasance. Under current federal tax law, we can make the same type of deposit described above and be released from any restrictive covenants in the indenture specified in a prospectus supplement. This is called "covenant defeasance." In that event, you would lose the protection of any such covenants but would gain the protection of having money and obligations issued or guaranteed by the U.S. government set aside in trust to repay the debt securities. In order to achieve covenant defeasance, we must do the following:

- deposit in trust for your benefit and the benefit of all other direct holders of the debt securities a combination of money and obligations issued or guaranteed by the U.S. government that will generate enough cash to make interest, principal and any other payments on the debt securities on their various due dates; and
- deliver to the trustee a legal opinion of our counsel confirming that, under current federal income tax law, we may make the above deposit without causing you to be taxed on the debt securities any differently than if we did not make the deposit and just repaid the debt securities ourselves at maturity.

If we accomplish covenant defeasance, you can still look to us for repayment of the debt securities if there were a shortfall in the trust deposit or the trustee is prevented from making payment. In fact, if one of the remaining Events of Default occurred, such as our bankruptcy, and the debt securities became immediately due and payable, there may be a shortfall. Depending on the event causing the default, you may not be able to obtain payment of the shortfall.

Debt Securities Issued in Non-Global Form

If any debt securities cease to be issued in global form, they will be issued:

- only in fully registered form;
- without interest coupons; and
- unless we indicate otherwise in the prospectus supplement, in denominations of $1,000 and amounts that are integral multiples of $1,000.

Holders may exchange their debt securities that are not in global form for debt securities of smaller denominations or combined into fewer debt securities of larger denominations, as long as the total principal amount is not changed.

Holders may exchange or transfer their debt securities at the office of the trustee. We may appoint the trustee to act as our agent for registering debt securities in the names of holders transferring debt securities, or we may appoint another entity to perform these functions or perform them ourselves.

Holders will not be required to pay a service charge to transfer or exchange their debt securities, but they may be required to pay for any tax or other governmental charge associated with the transfer or exchange. The transfer or exchange will be made only if our transfer agent is satisfied with the holder's proof of legal ownership.

If we have designated additional transfer agents for a holder's debt security, they will be named in any prospectus supplement. We may appoint additional transfer agents or cancel the appointment of any particular transfer agent. We may also approve a change in the office through which any transfer agent acts.

If any debt securities are redeemable and we redeem less than all those debt securities, we may stop the transfer or exchange of those debt securities during the period beginning 15 days before the day we mail the notice of redemption and ending on the day of that mailing, in order to freeze the list of holders to prepare the mailing. We may also refuse to register transfers or exchanges of any debt securities selected for redemption, except that we will continue to permit transfers and exchanges of the unredeemed portion of any debt security that will be partially redeemed.

If a debt security is issued as a global security, only the depository will be entitled to transfer and exchange the debt security as described in this section, since it will be the sole holder of the debt security.

Payment Mechanics

Who Receives Payment? If interest is due on a debt security on an interest payment date, we will pay the interest to the person or entity in whose name the debt security is registered at the close of business on the regular record date, discussed below, relating to the interest payment date. If interest is due at maturity but on a day that is not an interest payment date, we will pay the interest to the person or entity entitled to receive the principal of the debt security. If principal or another amount besides interest is due on a debt security at maturity, we will pay the amount to the holder of the debt security against surrender of the debt security at a proper place of payment, or, in the case of a global security, in accordance with the applicable policies of the depository.

Payments on Global Securities. We will make payments on a global security in accordance with the applicable policies of the depository as in effect from time to time. Under those policies, we will pay directly to the depository, or its nominee, and not to any indirect holders who own beneficial interests in the global security. An indirect holder's right to those payments will be governed by the rules and practices of the depository and its participants, as described under "What Is a Global Security?".

Payments on Non-Global Securities. For a debt security in non-global form, we will pay interest that is due on an interest payment date by check mailed on the interest payment date to the holder at his or her address shown on the trustee's records as of the close of business on the regular record date. We will make all other payments by check, at the paying agent described below, against surrender of the debt security. We will

make all payments by check in next-day funds; for example, funds that become available on the day after the check is cashed.

Alternatively, if a non-global security has a face amount of at least $1,000,000 and the holder asks us to do so, we will pay any amount that becomes due on the debt security by wire transfer of immediately available funds to an account at a bank in New York City on the due date. To request wire payment, the holder must give the paying agent appropriate transfer instructions at least five business days before the requested wire payment is due. In the case of any interest payment due on an interest payment date, the instructions must be given by the person who is the holder on the relevant regular record date. In the case of any other payment, we will make payment only after the debt security is surrendered to the paying agent. Any wire instructions, once properly given, will remain in effect unless and until new instructions are given in the manner described above.

Regular Record Dates. We will pay interest to the holders listed in the trustee's records as the owners of the debt securities at the close of business on a particular day in advance of each interest payment date. We will pay interest to these holders if they are listed as the owner even if they no longer own the debt security on the interest payment date. That particular day, usually about two weeks in advance of the interest payment date, is called the "regular record date" and will be identified in the prospectus supplement.

Payment When Offices Are Closed. If any payment is due on a debt security on a day that is not a business day, we will make the payment on the next business day. Payments postponed to the next business day in this situation will be treated under the indenture as if they were made on the original due date. A postponement of this kind will not result in a default under any debt security or the indenture, and no interest will accrue on the postponed amount from the original due date to the next business day.

Paying Agents. We may appoint one or more financial institutions to act as our paying agents, at whose designated offices debt securities in non-global form may be surrendered for payment at their maturity. We call each of those offices a paying agent. We may add, replace or terminate paying agents from time to time. We may also choose to act as our own paying agent. Initially, we have appointed the trustee, at its corporate trust office in New York City, as the paying agent. We must notify you of changes in the paying agents.

Book-entry and other indirect holders should consult their banks or brokers for information on how they will receive payments on their debt securities.

The Trustee Under the Indenture

We will identify the trustee under the indenture for our debt securities in the prospectus supplement for such securities.

The trustee may resign or be removed with respect to one or more series of debt securities and a successor trustee may be appointed to act with respect to these series.

DESCRIPTION OF COMMON STOCK

Our authorized capital stock consists of 200,000,000 shares of common stock, of which 82,077,463 shares were outstanding on November 30, 2006. Each of our shares of common stock is entitled to one vote on all matters voted upon by shareholders. Our shareholders do not have cumulative voting rights. Our issued and outstanding shares of common stock are fully paid and nonassessable. There are no redemption or sinking fund provisions applicable to the shares of our common stock, and such shares are not entitled to any preemptive rights. Since we are incorporated in both Texas and Virginia, we must comply with the laws of both states when issuing shares of our common stock.

Holders of our shares of common stock are entitled to receive such dividends as may be declared from time to time by our board of directors from our assets legally available for the payment of dividends and, upon our liquidation, a pro rata share of all of our assets available for distribution to our shareholders.

Under the provisions of some of our debt agreements, we have agreed to restrictions on the payment of cash dividends. Under these restrictions, our cumulative cash dividends paid after December 31, 1985 may not exceed the sum of our accumulated consolidated net income for periods after December 31, 1985 plus approximately $9.0 million. As of September 30, 2006, approximately $203.3 million was available for the declaration of dividends under these restrictions.

American Stock Transfer & Trust Company is the registrar and transfer agent for our common stock.

Charter and Bylaw Provisions

Some provisions of our articles of incorporation and bylaws may be deemed to have an "anti-takeover" effect. The following description of these provisions is only a summary, and we refer you to our restated articles of incorporation and bylaws for more information since their terms affect your rights as a shareholder.

Classification of the Board. Our board of directors is divided into three classes, each of which consists, as nearly as may be possible, of one-third of the total number of directors constituting the entire board. There are currently 13 directors serving on the board. Each class of directors serves a three-year term. At each annual meeting of our shareholders, successors to the class of directors whose term expires at the annual meeting are elected for three-year terms. Our restated articles of incorporation prohibit cumulative voting. In general, in the absence of cumulative voting, one or more persons who hold a majority of our outstanding shares can elect all of the directors who are subject to election at any meeting of shareholders.

The classification of directors could have the effect of making it more difficult for shareholders, including those holding a majority of the outstanding shares, to force an immediate change in the composition of our board. Two shareholder meetings, instead of one, generally will be required to effect a change in the control of our board. Our board believes that the longer time required to elect a majority of a classified board will help to ensure the continuity and stability of our management and policies since a majority of the directors at any given time will have had prior experience as our directors.

Removal of Directors. Our restated articles of incorporation and bylaws also provide that our directors may be removed only for cause and upon the affirmative vote of the holders of at least 75 percent of the shares then entitled to vote at an election of directors.

Fair Price Provisions. Article VII of our articles of incorporation provides certain "Fair Price Provisions" for our shareholders. Under Article VII, a merger, consolidation, sale of assets, share exchange, recapitalization or other similar transaction, between us or a company controlled by or under common control with us and any individual, corporation or other entity which owns or controls 10 percent or more of our voting capital stock, would be required to satisfy the condition that the aggregate consideration per share to be received in the transaction for each class of our voting capital stock be at least equal to the highest per share price, or equivalent price for any different classes or series of stock, paid by the 10 percent shareholder in acquiring any of its holdings of our stock. If a proposed transaction with a 10 percent shareholder does not meet this condition, then the transaction must be approved by the holders of at least 75 percent of the outstanding shares of voting capital stock held by our shareholders other than the 10 percent shareholder unless a majority of the directors who were members of our board immediately prior to the time the 10 percent shareholder involved in the proposed transaction became a 10 percent shareholder have either:

- expressly approved in advance the acquisition of the outstanding shares of our voting capital stock that caused the 10 percent shareholder to become a 10 percent shareholder, or
- approved the transaction either in advance of or subsequent to the 10 percent shareholder becoming a 10 percent shareholder.

The provisions of Article VII may not be amended, altered, changed, or repealed except by the affirmative vote of at least 75 percent of the votes entitled to be cast thereon at a meeting of our shareholders duly called for consideration of such amendment, alteration, change, or repeal. In addition, if there is a 10 percent shareholder, such action must also be approved by the affirmative vote of at least 75 percent of the outstanding shares of our voting capital stock held by the shareholders other than the 10 percent shareholder.

Shareholder Proposals and Director Nominations. Our shareholders can submit shareholder proposals and nominate candidates for the board of directors if the shareholders follow the advance notice procedures described in our bylaws.

Shareholder proposals must be submitted to our corporate secretary at least 60 days, but not more than 85 days, before the annual meeting; provided, however, that if less than 75 days' notice or prior public disclosure of the date of the annual meeting is given or made to shareholders, notice by the shareholder to be timely must be received by our Secretary not later than the close of business on the 25th day following the day on which such notice of the date of the annual meeting was mailed or such public disclosure was made. The notice must include a description of the proposal, the shareholder's name and address and the number of shares held, and all other information which would be required to be included in a proxy statement filed with the SEC if the shareholder were a participant in a solicitation subject to the SEC proxy rules. To be included in our proxy statement for an annual meeting, we must receive the proposal at least 120 days prior to the anniversary of the date we mailed the proxy statement for the prior year's annual meeting.

To nominate directors, shareholders must submit a written notice to our corporate secretary at least 60 days, but not more than 85 days, before a scheduled meeting; provided, however, that if less than 75 days' notice or prior public disclosure of the date of the annual meeting is given or made to shareholders, such nomination shall have been received by our Secretary not later than the close of business on the 25th day following the day on which such notice of the date of the annual meeting was mailed or such public disclosure was made. The notice must include the name and address of the shareholder and of the shareholder's nominee, the number of shares held by the shareholder, a representation that the shareholder is a holder of record of common stock entitled to vote at the meeting, and that the shareholder intends to appear in person or by proxy to nominate the persons specified in the notice, a description of any arrangements between the shareholder and the shareholder's nominee, information about the shareholder's nominee required by the SEC, and the written consent of the shareholder's nominee to serve as a director.

Shareholder proposals and director nominations that are late or that do not include all required information may be rejected. This could prevent shareholders from bringing certain matters before an annual or special meeting or making nominations for directors.

Shareholder Rights Plan

On November 12, 1997, our board of directors declared a dividend distribution of one right for each outstanding share of our common stock to shareholders of record at the close of business on May 10, 1998. Each right entitles the registered holder to purchase from us one-tenth share of our common stock at a purchase price of $8.00 per share, subject to adjustment. The description and terms of the rights are set forth in a rights agreement between us and the rights agent.

Subject to exceptions specified in the rights agreement, the rights will separate from our common stock and a distribution date will occur upon the earlier of:

- ten business days following a public announcement that a person or group of affiliated or associated persons has acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock, other than as a result of repurchases of stock by us or specified inadvertent actions by institutional or other shareholders;
- ten business days, or such later date as our board of directors shall determine, following the commencement of a tender offer or exchange offer that would result in a person or group having acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock; or
- ten business days after our board of directors shall declare any person to be an adverse person within the meaning of the rights plan.

The rights expire at 5:00 P.M., Eastern time, on May 10, 2008, unless extended prior thereto by our board or earlier if redeemed by us.

The rights will not have any voting rights. The exercise price payable and the number of shares of our common stock or other securities or property issuable upon exercise of the rights are subject to adjustment from time to time to prevent dilution. We issue rights when we issue our common stock until the rights have separated from the common stock. After the rights have separated from the common stock, we may issue additional rights if the board of directors deems such issuance to be necessary or appropriate.

The rights have "anti-takeover" effects and may cause substantial dilution to a person or entity that attempts to acquire us on terms not approved by our board of directors except pursuant to an offer conditioned upon a substantial number of rights being acquired. The rights should not interfere with any merger or other business combination approved by our board of directors because, prior to the time that the rights become exercisable or transferable, we can redeem the rights at $.01 per right.

Other

As part of the consideration for our MVG acquisition in December 2002, we issued shares of common stock to the owners of that company for a portion of the purchase price. In connection with the acquisition, these parties agreed, for up to five years from the closing of the acquisition, and with some exceptions, not to sell or transfer shares representing more than 1 percent of our total outstanding voting securities to any person or group or any shares to a person or group who would hold more than 9.9 percent of our total outstanding voting securities after the sale or transfer. This restriction, and other agreed restrictions on the ability of these shareholders to acquire additional shares, participate in proxy solicitations or act to seek control, may be deemed to have an "anti-takeover" effect.

PLAN OF DISTRIBUTION

We may sell the securities offered by this prospectus and a prospectus supplement as follows:

- through agents;
- to or through underwriters;
- through dealers;
- directly by us to purchasers; or
- through a combination of any such methods of sale.

We, directly or through agents or dealers, may sell, and the underwriters may resell, the securities in one or more transactions, including:

- transactions on the New York Stock Exchange or any other organized market where the securities may be traded;
- in the over-the-counter market;
- in negotiated transactions; or
- through a combination of any such methods of sale.

The securities may be sold at a fixed price or prices which may be changed, at market prices prevailing at the time of sale, at prices related to such prevailing market prices or at negotiated prices.

Agents designated by us from time to time may solicit offers to purchase the securities. We will name any such agent involved in the offer or sale of the securities and set forth any commissions payable by us to such agent in a prospectus supplement relating to any such offer and sale of securities. Unless otherwise indicated in the prospectus supplement, any such agent will be acting on a best efforts basis for the period of its appointment. Any such agent may be deemed to be an underwriter of the securities, as that term is defined in the Securities Act.

If underwriters are used in the sale of securities, securities will be acquired by the underwriters for their own account and may be resold from time to time in one or more transactions. Securities may be offered to the public either through underwriting syndicates represented by one or more managing underwriters or directly by one or more firms acting as underwriters. If an underwriter or underwriters are used in the sale of securities, we will execute an underwriting agreement with such underwriter or underwriters at the time an agreement for such sale is reached. We will set forth in the prospectus supplement the names of the specific managing underwriter or underwriters, as well as any other underwriters, and the terms of the transactions, including compensation of the underwriters and dealers. Such compensation may be in the form of discounts, concessions or commissions. Underwriters and others participating in any offering of securities may engage in transactions that stabilize, maintain or otherwise affect the price of such securities. We will describe any such activities in the prospectus supplement.

We may elect to list any class or series of securities on any exchange, but we are not currently obligated to do so. It is possible that one or more underwriters, if any, may make a market in a class or series of securities, but the underwriters will not be obligated to do so and may discontinue any market making at any time without notice. We cannot give any assurance as to the liquidity of the trading market for any of the securities we may offer.

If a dealer is used in the sale of the securities, we or an underwriter will sell such securities to the dealer, as principal. The dealer may then resell such securities to the public at varying prices to be determined by such dealer at the time of resale. The prospectus supplement will set forth the name of the dealer and the terms of the transactions.

We may directly solicit offers to purchase the securities, and we may sell directly to institutional investors or others. These persons may be deemed to be underwriters within the meaning of the Securities Act with respect to any resale of the securities. The prospectus supplement will describe the terms of any such sales, including the terms of any bidding, auction or other process, if used.

Agents, underwriters and dealers may be entitled under agreements which may be entered into with us to indemnification by us against specified liabilities, including liabilities under the Securities Act, or to contribution by us to payments they may be required to make in respect of such liabilities. The prospectus supplement will describe the terms and conditions of such indemnification or contribution. Some of the agents, underwriters or dealers, or their affiliates, may engage in transactions with or perform services for us and our subsidiaries in the ordinary course of their business.

LEGAL MATTERS

Gibson, Dunn & Crutcher LLP, Dallas, Texas, and Hunton & Williams LLP, Richmond, Virginia, have each rendered an opinion with respect to the validity of the securities that may be offered under this prospectus. We filed these opinions as exhibits to the registration statement of which this prospectus is a part. If counsel for any underwriters passes on legal matters in connection with an offering made under this prospectus, we will name that counsel in the prospectus supplement relating to that offering.

EXPERTS

The consolidated financial statements of Atmos Energy Corporation appearing in Atmos Energy Corporation's Annual Report (Form 10-K) for the year ended September 30, 2006 and Atmos Energy Corporation management's assessment of the effectiveness of internal control over financial reporting as of September 30, 2006 included therein have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their reports thereon included therein, and incorporated herein by reference. Such consolidated financial statements and management's assessment have been incorporated herein by reference in reliance upon such reports given on the authority of such firm as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission under the Securities Exchange Act of 1934. You may read and copy this information at the Public Reference Room of the SEC, 100 F Street, N.E., Washington, D.C. 20549, at prescribed rates. You may obtain information on the operation of the Public Reference Room by calling the SEC at (800) SEC-0330.

The SEC also maintains an internet Web site that contains reports, proxy statements and other information about issuers, like us, who file electronically with the SEC. The address of that site is *www.sec.gov.*

You can also inspect reports, proxy statements and other information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

We have filed with the SEC a registration statement on Form S-3 that registers the securities we are offering. The registration statement, including the attached exhibits and schedules, contains additional relevant information about us and the securities offered. The rules and regulations of the SEC allow us to omit certain information included in the registration statement from this prospectus.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The SEC allows us to "incorporate by reference" information in this prospectus that we have filed with it. This means that we can disclose important information to you by referring you to another document filed separately with the SEC. The information incorporated by reference is considered to be part of this prospectus, except for any information that is superseded by information that is included directly in this prospectus or any prospectus supplement relating to an offering of our securities.

We incorporate by reference into this prospectus the documents listed below and any future filings we make with the SEC under sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 prior to the termination of our offering of securities. These additional documents include periodic reports, such as annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K (other than information furnished under Items 2.02 and 7.01, which is deemed not to be incorporated by reference in this prospectus), as well as proxy statements. You should review these filings as they may disclose a change in our business, prospects, financial condition or other affairs after the date of this prospectus.

This prospectus incorporates by reference the documents listed below that we have filed with the SEC but have not been included or delivered with this document:

- Our annual report on Form 10-K for the year ended September 30, 2006; and
- Our current reports on Form 8-K filed with the SEC on October 20, 2006, November 13, 2006 and December 4, 2006.

These documents contain important information about us and our financial condition.

You may obtain a copy of any of these filings, or any of our future filings, from us without charge by requesting it in writing or by telephone at the following address or telephone number:

Atmos Energy Corporation
1800 Three Lincoln Centre
5430 LBJ Freeway
Dallas, Texas 75240
Attention: Susan Kappes Giles
(972) 934-9227

Our internet Web site address is *www.atmosenergy.com.* Information on or connected to our internet Web site is not part of this prospectus.

5,500,000 Shares

Atmos Energy Corporation

Common Stock

PROSPECTUS SUPPLEMENT
December 7, 2006

LEHMAN BROTHERS

GOLDMAN, SACHS & CO.

BANC OF AMERICA SECURITIES LLC

JPMORGAN

MERRILL LYNCH & CO.

SUNTRUST ROBINSON HUMPHREY

WACHOVIA SECURITIES

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 206
Witness: Laurie Sherwood

Data Request:

Please provide copies of all studies performed by the Company, or by consultants or investment firms hired by the Company, to assess (1) the Company's financial performance, (2) the performance of the Company relative to other utilities, or (3) the adequacy of the Company's return on equity or overall rate of return.

Response:

Outside of typical studies for rate filing purposes, the Company has not performed nor had performed any such studies.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 207
Witness: Dan Meziere

Data Request:

Please provide the Company's return on equity on a quarterly basis for the years 2004-2006 for the Company's seven regulated gas divisions: Louisiana Division, Mid-States Division, West Texas Division, Mid-Tex Division, Mississippi Valley Gas Company Division, Kentucky Division, and the Colorado-Kansas Division.

Response:

The Company's regulated natural gas distribution operations are comprised of seven operating divisions of Atmos Energy Corporation as of September 30, 2006. Accordingly, there is only one capital structure for the Company's utility operations, and it is the same for each division. Except for ratemaking purposes, actual return on equity is not calculated for divisions. Any attempt to calculate an actual return on equity at the state level without making all appropriate ratemaking adjustments or allocation of ratebase items which comprise shared services plant, deferred taxes, etc., would not be meaningful. The schedule shown below provides the quarterly return on equity, based on a rolling 12-month basis, for all of the Company's natural gas distribution operations for fiscal years 2004-2006.

Atmos Energy Corporation
Schedule of Utility ROE By Quarter
Fiscal 2004 - 2006

Fiscal Quarter	ROE
Q1-2004	9.1%
Q2-2004	8.0%
Q3-2004	8.4%
Q4-2004	7.8%
Q1-2005	8.6%
Q2-2005	9.8%
Q3-2005	8.3%
Q4-2005	6.7%
Q1-2006	7.6%
Q2-2006	6.0%
Q3-2006	5.0%
Q4-2006	4.4%

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 208
Witness: Jim Cagle

Data Request:

Please provide the Company's allowed return on equity for the years 2004-2006 for the Company's seven regulated gas divisions: Louisiana Division, Mid-States Division, West Texas Division, Mid-Tex Division, Mississippi Valley Gas Company Division, Kentucky Division, and the Colorado-Kansas Division. Please provide the case number date of the proceeding establishing the authorized return on equity.

Response:

The Company's allowed return on equity for fiscal years 2004-2006 for each of the Company's natural gas distribution operations, along with the associated case number, is included in the attached spreadsheet labeled AG DR1-208 ATT.

Atmos Energy Corporation
Kentucky Data Requests
Response to AG's First DR # 208

Division	Jurisdiction	Authorized Return on Equity As of September 30, 2004	2005	2006	Case Number
Colorado-Kansas	Colorado	11.25% - 12.50%	11.25%	11.25%	02S-411G
	Kansas	(1)	(1)	(1)	03-ATMG-1036-RTS
Louisiana	TransLa	10.50% - 11.50%	10.50% - 11.50%	10.00% - 10.80%	U-21922/U-23508; U-28588
	LGS	10.88% - 11.50%	10.88% - 11.50%	10.40%	U-21484-A; U-28587
Mid-States	Georgia	11.50%	11.50%	10.13%	20298-U; 6691-U
	Illinois	11.56%	11.56%	11.56%	00-0228
	Iowa	11.00%	11.00%	11.00%	RPU-01-2, TF-01-68
	Missouri	12.15%	12.15%	12.15%	GR-95-160
	Tennessee	(1)	(1)	(1)	95-02258
	Virginia	10.00%	9.50% - 10.50%	9.50% - 10.50%	PUE-2003-00507
Mid-Tex	Texas	8.258%	8.258%	8.258%	GUD-9400
Mississippi	Mississippi	9.80%	9.80%	9.80%	92-UN-0230
West Texas	Amarillo	12.00%	12.00%	12.00%	GUD-9539
	Lubbock	11.25%	11.25%	11.25%	GUD - 9563
	West Texas	10.50%	10.50%	10.50%	GUD - 9573

(1) - An allowed return on equity was not included in the respective state commission's final decision.