RECEIVED

MAR 16 2007

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 161 – DR 199

MARCH 16, 2007

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 161
Respondent: Chris Forsythe

Data Request:

Provide the "credit adjusted risk free rate" used for any and all ARO calculations under FASB Statement No. 143, FIN 47, and FERC Order No. 631 calculations to date.

Response:

The credit adjusted risk free rate used for the ARO calculation was 6.46%. The supporting information for this rate was provided in response to question AG DR1-157.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 162
Respondent: Chris Forsythe

Data Request:

Provide complete copies of all Board of Director's minutes and internal management meeting minutes during the past five years in which any or all of the following subjects were discussed: the Company's gas plant and/or SSU plant depreciation rates; retirement unit costs; SFAS No. 143; FIN 47; and, FERC RM02-7-000.

Response:

There are no Board of Director minutes or internal management meeting minutes that document discussions of the Company's gas plant and/or SSU plant depreciation rates, retirement unit costs, SFAS 143, FIN 47 or FERC RM 02-7-000.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 163
Respondent: Chris Forsythe

Data Request:

Provide the accounting entries (debits and credits) used to implement SFAS No. 143 and FIN 47, along with all workpapers supporting those entries. Provide all these workpapers and calculations in electronic format (Excel) with all formulae intact. Please include the workpapers supporting the reclassification of "$15.1 million from regulatory cost of removal liability to asset retirement obligation" as discussed on page 74 of Atmos' September 30, 2006 Form 10K, along with the accounting entries relating to this reclassification.

Response:

The accounting entries and related calculations have been provided in response to question 157. The $15.1 million ARO was reclassified from the regulatory cost of removal liability because the asset retirement cost had already been recognized as a component of depreciation expense with a corresponding increase to the regulatory cost of removal liability.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 164
Witness: Don Roff

Data Request:

What impact, if any, did the application of FIN 47 have upon the proposed depreciation rates and expense in this rate case? Provide all workpapers supporting the answer. If it had no impact, please explain why not.

Response:

FIN 47 had no impact on the depreciation study. FIN 47 is a financial reporting requirement and has nothing to do with regulatory depreciation.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 165
Respondent: Chris Forsythe

Data Request:

Please refer to page 74 of Atmos's September 30, 2006 Form 10K, where it states, "The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual."

a. Is this statement referring to the regulatory cost of removal obligation of $261,376 thousand (2006) and $263,424 thousand (2005) shown on pages 120 and 121 of the Form 10K? If not, please provide the amounts this statement refers to.

b. Please provide the workpapers supporting the calculation of the $261,376 thousand (2006) and $263,424 thousand (2005) regulatory cost of removal obligations shown on pages 120 and 121 of the Form 10K. Please provide these workpapers in electronic format (Excel), with all formulae intact.

c. Provide a calculation, by account, of how much of these amounts relate to Atmos's Kentucky Properties, and separately, how much relate to the SSU properties. Provide all workpapers supporting these calculations, in electronic format (Excel), with all formulae intact.

d. Provide an analysis of the regulatory liability for cost of removal since inception identifying and explaining each debit and credit entry and amount.

Response:

a. The statement referred to in data request 165a relates to the $261,376 (thousand) and $263,424 (thousand) amounts reflected in the balance sheet.

b. See the attached calculation (Case 2006-00464 AG DR 165b att 1 Cost of removal liability rollforward.xls). Prior to September 30, 2003, the regulatory cost of removal obligation was recorded as a component of accumulated depreciation. In March 2004, the Securities and Exchange Commission informally communicated to the gas utility industry through the American Gas Association that this liability should be reflected as a separate liability on the face of the balance sheet. Beginning in June 2004, Atmos Energy separately reported the regulatory cost of removal obligation <u>for financial reporting purposes only</u>. Accordingly, <u>no</u> corresponding entry was recorded in the general ledger.

In order to determine the amount of accumulated depreciation that initially related to the regulatory cost of removal liability as of September 30, 2003, the Company obtained the accumulated depreciation by plant account from the general ledger and multiplied the related balance by the negative salvage value percentage obtained from the 1997 Kentucky depreciation study prepared by Deloitte & Touche.

Once the initial balance as of September 30, 2003 was established, this account was rolled forward on a quarterly basis. The associated accrual was calculated by multiplying the actual depreciation expense for the quarter by the negative salvage value rate described above. All removal costs were obtained from the general ledger and were recorded as a reduction to the liability. The ending balance was then reclassified <u>for financial reporting purposes only</u> from accumulated depreciation to a separate liability on the face of the balance sheet.

c. See the attached calculation (Case 2006-00464 AG DR 165cd att1 Kentucky and SSU COR rollforward.xls). The method of calculating the Kentucky and SSU cost of removal liabilities was the same as that described in the preceding response.

d. See response to item c.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 166
Witness: Tom Petersen

Data Request:

Provide Atmos's projection of the annual year-end balance in the regulatory liability for cost of removal, for the next 20 years. If not available for the next twenty years provide for as many years into the future that the projection is available. If this projection has not been made, explain why not.

a. Provide the amounts as they relate to Kentucky properties and the SSU properties.
b. For this projection assume that all of Atmos's proposed depreciation rates are approved as requested. Provide in hard copy and in electronic format with all formulae intact.
c. Explain all assumptions used to make this projection.

Response:

Atmos does not make balance sheet projections as part of its budgeting and planning process. Therefore, the company does not have a projection of the portion of accumulated depreciation identified as related to cost of removal.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 167
Witness: Tom Petersen

Data Request:

With respect to the Regulatory Liability relating to cost of removal which Atmos reclassified out of accumulated depreciation:

a. Does Atmos agree that this constitutes a regulatory liability for regulatory purposes in Kentucky and for FERC purposes? If not, explain why not.
b. Does Atmos agree that this amount is a refundable obligation to ratepayers until it is spent on its intended purpose (cost of removal)? If not, why not?
c. Explain the repayment provisions associated with this regulatory liability.
d. Explain when Atmos expects to spend this money for cost of removal.
e. Explain what Atmos has done with this money as Atmos has collected it. If you say that you have spent it on plant additions, please prove it.
f. Identify and explain all other similar examples of Atmos's advance collections of estimated future costs for which it does not have a legal obligation.
g. Does Atmos agree that the Kentucky Public Service Commission will never know whether or not Atmos will actually spend all of this money for cost of removal until and if Atmos goes out of business? If not, why not?
h. Does Atmos believe that amounts recoded in accumulated depreciation represent capital recovery? If not, why not?
i. Whose capital is reflected in accumulated depreciation – shareholders' or ratepayers'?

Response:

a. No. The reclassification of cost of removal was made for financial reporting purposes only and has nothing to do with regulatory depreciation.

b. No. See the response to part (a) of this request.

c. See the responses to parts (a) and (b) of this request.

d. The company spends cash for cost of removal as payments are made for the removal of the assets for which cost of removal is incurred. Since accumulated depreciation does not represent a cash fund the reference to "this money" in the request is unclear.

e. See the response to part (d) of this request.

f. The company uses accrual accounting as required by the uniform system of accounts. Therefore, the recognition of expenses and revenues are not coincident with cash payments. For example, the company recognizes unbilled revenue at the end of each month.

g. No, Atmos does not agree with that statement for the reasons explained in the responses to part (d) of this request and parts (b) and (c) of item 165.

h. No. Depreciation accounting distributes the cost of assets less salvage over the assets' estimated useful life in a systematic and rational manner. The entry to record depreciation expense for an asset also records accumulated depreciation reducing the net book value of that asset. Depreciation is a process of allocating costs over time and not a process of recovering capital.

i. See the response to part (h) of this request.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 168
Witness: Don Roff

Data Request:

Please provide the calculation of the annual amount of future cost of removal and gross salvage incorporated into the Company's existing depreciation rates and proposed depreciation rates by account.

Response:

Please see the worksheets attached to this data request and collectively labeled AG DR1-168 ATT.

ATMOS ENERGY CORPORATION - KENTUCKY
Book Depreciation Study as of September 30, 2005
Comparison of Mortality Characteristics

REPONSE TO AG 1-168

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]		
		EXISTING			RECOMMENDED								
Account	Description	ASL yrs.	Iowa Curve	Net Salvage %	ASL yrs.	Iowa Curve	Gross Salvage %	Cost of Removal %	Net Salvage %	COR Rate %	Salvage Rate %	COR Accrual $	Salvage Accrual $
	PRODUCTION PLANT												
325.20	Producing Leaseholds	-	-	-	50	R5	0	0	0				
325.40	Rights-of-Way	-	-	-	50	R5	0	0	0				
336.00	Purification Equipment	-	-	-	50	R5	0	5	(5)	0.10		44	
	STORAGE PLANT												
351.00	Structures and Improvements	45	R4	(5)	50	R2	5	0	5		0.10		(309)
352.00	Well Construction and Equipment	50	R3	(50)	50	R3	0	40	(40)	0.80		17,411	
352.03	Cushion Gas	-	-	-	50	SQ	0	0	0				
352.11	Storage Rights	40	R5	0	50	R5	0	0	0				
354.00	Compressor Station Equipment	40	S4	(10)	50	R1.5	0	0	0				
355.00	M&R Station Equipment	40	S1.5	0	50	R2	0	0	0				
	TRANSMISSION PLANT												
365.20	Rights-of-Way	60	R5	0	55	R5	0	0	0				
366.00	Structures and Improvements	45	R3	0	50	R3	0	0	0				
367.00	Mains	50	R5	(5)	55	R1	0	25	(25)	0.45		100,203	
369.00	M&R Station Equipment	40	S1.5	0	45	R0.5	0	2	(2)	0.04		1,312	
	DISTRIBUTION PLANT												
374.02	Land Rights	60	R5	0	55	R5	0	0	0				
375.00	Structures and Improvements	50	R3	0	50	L0	0	10	(10)	0.20		937	
376.00	Mains	50	R1.5	(5)	55	R0.5	0	25	(25)	0.45		436,022	
378.00	M&R Station Equipment	40	S1.5	0	50	R1	0	5	(5)	0.10		2,618	
379.00	City Gate Equipment	40	S1.5	0	50	R1	0	15	(15)	0.30		8,413	
380.00	Services	45	R1	(150)	40	R1.5	0	75	(75)	1.88		1,297,318	
381.00	Meters	35	R2	0	25	R0.5	0	25	(25)	1.00		137,757	
382.00	Meter Installations	35	R2	0	40	R1	0	25	(25)	0.63		208,493	
383.00	House Regulators	35	R2	10	30	S6	0	0	0				
384.00	House Regulator Installations	35	R2	0	35	R2	0	0	0				
385.00	Industrial M&R Equipment	40	S1.5	0	40	L5	2	17	(15)	0.43	0.05	18,842	(2,217)
	GENERAL PLANT												
390.00	Structures and Improvements	45	R3	(5)	15	L2	0	0	0				
390.09	Improvements to Leased Premises	20	SQ	0	25	R4	0	0	0				
391.00	Office Furniture and Equipment	15	S4	5	18	L0	0	0	0				
392.00	Transportation Equipment	8	R1.5	15	8	S5	10	0	10		1.25		(952)
394.00	Tools, Shop and Garage Equipment	30	S1	0	20	S6	1	0	1		0.05		(1,059)
396.00	Power Operated Equipment	15	L2	10	15	L5	5	0	5		0.33		(2,212)
397.00	Communication Equipment	15	S5	0	20	S2	0	0	0				
398.00	Miscellaneous Equipment	10	R3	0	20	R5	0	0	0				
399.01	OTP - Servers Hardware	7	SQ	0	10	SQ	0	0	0				
399.03	OTP - Network Hardware	7	SQ	0	10	SQ	0	0	0				
399.06	OTP - PC Hardware	5	R5	0	10	L1	2	0	2		0.20		(5,406)
399.07	OTP - PC Software	5	R5	0	5	S1.5	0	0	0				
399.08	OTP - Application Software	8	SQ	0	8	R5	0	0	0				
	TOTALS											**2,229,370**	**(12,155)**

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 169
Witness: Don Roff

Data Request:

Are the amounts of cost of removal and gross salvage incorporated into the existing and proposed depreciation rates the same as they would have been in the absence of SFAS No. 143 and FIN 47? Please explain.

Response:

Yes. SFAS 143 and FIN 47 are financial reporting requirements and have nothing to do with regulatory depreciation.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 170
Respondent: Chris Forsythe
Witness: Tom Petersen

Data Request:

Are there any assets for which Atmos has determined it has a legal ARO under FIN 47 and/or SFAS No. 143, but has treated as a non-legal ARO in the Depreciation Studies? If so, please identify the accounts and the plant amounts.

Response:

FIN 47 had no impact on the depreciation study. FIN 47 is a financial reporting requirement and has nothing to do with regulatory depreciation.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 171
Witness: Tom Petersen

Data Request:

Does Atmos promise to remove each asset for which it is collecting cost of removal and does it promise to spend all of the money it is collecting for cost of removal, on cost of removal? Please explain.

Response:

The company will continue to remove assets that need to be removed in the course of providing gas utility service. See also the response to item 167.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 172
Witness: Don Roff

Data Request:

Identify with specificity each section and paragraph of the "Energy Policy Act of 2005" which has or may have an impact upon, or relates to in any way, the following, by FERC USOA account.

a. Plant lives
b. Plant retirement patterns (Iowa Curves)
c. Gross salvage
d. Cost of removal
e. Retirement units

Response:

Atmos is unaware of any impact that the Energy Policy Act of 2005 has upon any of the items listed.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 172
Respondent: Pace McDonald (i)

Data Request:

Identify with specificity each section and paragraph of the "Energy Policy Act of 2005" which has or may have an impact upon, or relates to in any way, the following, by FERC USOA account.

f. Accounting under FERC Uniform System of Accounts
g. Accounting under GAAP
h. Accounting under SEC rules
i. Deferred tax and any tax credits

Response:

The Energy Policy Act of 2005 did not impact Atmos Energy with respect to accounting under the FERC Uniform System of Accounts, US GAAP or SEC rules nor did it impact the deferred tax and tax credit amounts recorded at the time the legislation was passed.

The Act did modify, for tax depreciation purposes, the depreciable life of gas distribution assets. Prior to the Act's passage the depreciable life of gas distribution assets was 20 years. The Act modified the depreciable life to 15 years. As a result of this modification, tax depreciation on distribution assets will be claimed at a rate faster than prior to the Act's passage. This shorter depreciable tax life and accelerated tax depreciation will cause deferred tax liabilities associated with gas distribution assets to grow at a rate faster than prior to the Act's passage.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 172
Witness: Bernard Uffelman

Data Request:

Identify with specificity each section and paragraph of the "Energy Policy Act of 2005" which has or may have an impact upon, or relates to in any way, the following, by FERC USOA account.

j. Jurisdictional and class cost allocations

Response:

No sections or paragraphs of the Energy Policy Act of 2005 were identified that would have an impact on, or relate to in any way, the jurisdictional and class cost allocations as filed in this proceeding.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 173
Witness: Greg Waller

Data Request:

Please refer to the direct testimony of Greg Waller, page 17, lines 19 and 22. Please provide a calculation of the depreciation expense amounts shown on those lines. Provide the calculation in Excel with all formulae intact, and show the plant balances and applicable depreciation rates used to calculate the expense amounts.

Response:

There were errors in the original filing which have been revised and filed with AG DR 1 as well as provided here. These revisions resulted in updated depreciation expense amounts of $12,368,187 and $13,032,342 for the base and forecasted test periods respectively.

The 12 month depreciation numbers are calculated by taking the 13 month average investment multiplied by the annual accrual rate and then multiplied by a factor to reflect the capitalization of some depreciation expense. Depreciation on assets used in construction projects is capitalized. A factor representing the percent of depreciation that has been expensed rather than capitalized was calculated for each division. For those accounts where reserve already exceeds investment, no additional depreciation is calculated.

Please see the attachment Case 2006-00464 AG DR1-173 ATT. These schedules are sponsored by Tom Petersen as a part of the rate base calculation.

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account
Base Period Ended March 31, 2007

Data: _X_ Base Period ___ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).: ______________

FR 10(10)(b)3.2
Schedule B-3.2

Witness: Tom Petersen

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 month average Investment (D)	Reserve (E)	12 Month Expense (F)
1		Intangible Plant			
2	301.00	Organization	76,480	8,330	0
3	302.00	Franchises & Consents	119,853	119,853	0
4	303.00	Misc. Intangible Plant	408,053	0	0
5					
6		Total Intangible Plant	604,386	128,182	0
7					
8		Natural Gas Production Plant			
9	325.20	Producing Leaseholds	2,353	0	0
10	325.40	Rights of Ways	83,422	0	0
11	331.00	Production Gas Wells Equipment	3,492	3,492	0
12	332.01	Field Lines	47,163	47,163	0
13	332.02	Tributary Lines	528,218	529,956	0
14	334.00	Field Meas. & Reg. Sta. Equip	198,469	198,469	0
15	336.00	Purification Equipment	44,369	0	0
16					
17		Total Natural Gas Production Plant	907,486	779,080	0
18					
19		Storage Plant			
20	350.10	Land	261,127	0	0
21	350.20	Rights of Way	4,682	4,693	0
22	351.00	Sturctures & Improvements	4,700	1,672	90
23	351.02	Compression Station Equipment	159,811	116,065	3,049
24	351.03	Meas. & Reg. Sta. Structues	23,138	23,985	0
25	351.04	Other Structures	144,554	130,830	2,758
26	352.00	Wells \ Rights of Way	62,814	35,633	1,683
27	352.01	Well Construction	2,113,527	1,740,512	56,616
28	352.02	Well Equipment	531,954	557,582	0
29	352.03	Cushion Gas	1,694,833	15,237	0
30	352.10	Leaseholds	178,530	178,764	0
31	352.11	Storage Rights	54,614	51,150	988
32	353.01	Field Lines	178,501	183,071	0
33	353.02	Tributary Lines	209,458	214,822	0
34	354.00	Compressor Station Equipment	546,780	474,740	8,161
35	355.00	Meas & Reg. Equipment	288,851	286,074	5,882
36	356.00	Purification Equipment	243,119	244,496	0
37					
38			6,700,993	4,259,326	79,226

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account
Base Period Ended March 31, 2007

FR 10(10)(b)3.2
Schedule B-3.2

Witness: Tom Petersen

Data: _X_ Base Period ___ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).: _____________

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 month average Investment (D)	Reserve (E)	12 Month Expense (F)
1		Transmission Plant			
2	365.10	Land	26,970	16	0
3	365.20	Rights of Way	826,223	331,377	7,269
4	366.02	Structures & Improvements	214,065	13,509	2,941
5	366.03	Other Structues	69,172	60,525	950
6	367.00	Mains - Cathodic Protection	405,764	260,717	5,094
7	367.01	Mains - Steel	21,799,664	15,275,907	273,664
8	369.00	Meas. & Reg. Equipment	185,854	40,893	4,189
9	369.10	Meas. & Reg. Equipment	2,786,961	1,907,875	62,810
10					
11		*Total Transmission Plant*	26,314,674	17,890,819	356,917
12					
13		Distribution Plant			
14	374.00	Land & Land Rights	94,855	57,145	0
15	374.01	Land	51,571	0	0
16	374.02	Land Rights	229,318	22,177	3,808
17	374.03	Land Other	2,784	0	0
18	375.00	Structures & Improvements	312,033	25,754	6,015
19	375.01	Structures & Improvements T. B.	105,699	79,141	2,037
20	375.02	Land Rights	46,591	37,611	898
21	375.03	Improvements	4,005	176	77
22	376.00	*Mains Cathodic Protection*	10,029,188	1,842,869	236,935
23	376.01	Mains - Steel	64,078,064	38,182,268	1,513,812
24	376.02	Mains Plastic	25,597,506	7,946,520	604,728
25	378.00	Meas. & Reg. Sta. Equipment General	2,925,747	1,394,519	72,011
26	379.00	Meas. & Reg. Sta. Equipment City Gate	1,250,157	126,649	31,759
27	379.05	Meas. & Reg. Sta. Equipment - T. B.	1,636,212	1,196,831	41,566
28	380.00	Services	74,128,815	36,113,921	5,026,619
29	381.00	Meters	13,888,851	1,301,791	459,913
30	382.00	Meter Installations	34,727,743	5,646,466	1,050,420
31	383.00	House Regulators	5,043,023	2,561,379	142,069
32	384.00	House Reg. Installations	154,276	96,824	5,139
33	385.00	*Ind. Meas. & Reg. Sta. Equipment*	4,590,362	2,021,690	123,872
34	386.00	Other Property on Cust. Prem.	2,627	1,815	78
35					
36		Total Distribution Plant	238,899,427	98,655,544	9,321,757

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account
Base Period Ended March 31, 2007

FR 10(10)(b)3.2
Schedule B-3.2
Page 3 of 12
Witness: Tom Petersen

Data: _X_ Base Period ___ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).: ____________

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 month average Investment (D)	Reserve (E)	12 Month Expense (F)
1		General Plant			
2	389.00	Land & Land Rights	70,900	28,459	0
3	390.01	Structures Frame	65,954	6,345	1,645
4	390.02	Structures & Improvements	191,839	96,981	4,020
5	390.03	Improvements	774,269	84,269	16,225
6	390.04	Air Conditioning Equipment	13,888	7,215	247
7	390.09	Improvement to Leased Premises	1,934,060	1,456,286	108,229
8	391.00	Office Furniture & Equipment	2,708,532	1,447,111	146,055
9	391.02	Remittance Processing Equip	1,504	1,851	0
10	391.03	Office Machines	137,822	11,071	7,488
11	392.00	Transportation Equipment	550,273	(662,035)	48,132
12	392.01	Trucks	24,653	30,218	0
13	392.02	Trailers	122,165	122,848	0
14	393.00	Stores Equipment	4,071	2,967	278
15	394.00	Tools, Shop & Garage Equipment	1,668,225	191,405	54,413
16	396.00	Power Operated Equipment	3,125	3,208	0
17	396.03	Ditchers	247,306	(139,338)	6,820
18	396.04	Backhoes	278,287	15,074	7,675
19	396.05	Welders	43,558	2,846	1,201
20	397.00	Communication Equipment	2,649,915	1,112,383	166,458
21	397.01	Communication Equipment - Mobile Radios	3,338	(18,930)	172
22	397.02	Communication Equip. - Fixed Radios	41,432	6,084	2,134
23	397.05	Communication Equip. - Telemetering	312,236	86,204	16,080
24	398.00	Miscellaneous Equipment	2,704,586	919,819	275,322
25	399.00	Other Tangible Property	40,867	31,420	7,296
26	399.01	Other Tangible Property - Servers - H/W	1,022,046	691,318	120,830
27	399.02	Other Tangible Property - Servers - S/W	595,371	487,031	68,417
28	399.03	Other Tangible Property - Network Hardware	719,035	577,343	101,771
29	399.04	Other Tangible Property - CPU	56,964	61,388	0
30	399.05	Other Tangible Property - MF Hardware	60,318	63,364	0
31	399.06	Other Tangible Property - PC Hardware	3,812,543	3,315,027	693,329
32	399.07	Other Tang. Property - PC Software	486,027	346,682	74,746
33	399.08	Other Tang. Property - Application Software	6,985,037	3,780,595	573,208
34	399.09	Other Tangible Property - Mainframe S/W	134,331	148,380	0
35	399.24	Other Tang. Property - General Startup Costs	1,297,650	781,351	108,094
36					
37					
38		Total General Plant	29,762,128	15,096,240	2,610,286
39					
40		Total Plant	303,189,094	136,809,191	12,368,187

** All Intangible and General Plant amounts include Kentucky, Div. 09 general plant 100%, plus allocations of General Office general plant from Div. 02 at 5.20%, Div. 12 at 5.60% and Div 91 at 36.78%.

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account, KY only
Base Period Ended March 31, 2007

Data: _X_ Base Period ___ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).: _____________

FR 10(10)(b)3.2
Schedule B-3.2
Page 4 of 12
Witness: Tom Petersen

			Total Company Adjusted Jurisdiction			Annual
			13 month average		12 Month	Accrual
Line No. (A)	Acct. No. (B)	Account Titles (C)	Investment (D)	Reserve (E)	Expense (F)	Rate (G)
1		Intangible Plant				
2	301.00	Organization	8,330	8,330	0	0.00%
3	302.00	Franchises & Consents	119,853	119,853	0	0.00%
4	303.00	Misc. Intangible Plant	0	0	0	0.00%
5						
6		Total Intangible Plant	128,182	128,182	0	
7						
8		Natural Gas Production Plant				
9	325.20	Producing Leaseholds	2,353	0	0	0.00%
10	325.40	Rights of Ways	83,422	0	0	0.00%
11	331.00	Production Gas Wells Equipment	3,492	3,492	0	0.00%
12	332.01	Field Lines	47,163	47,163	0	0.00%
13	332.02	Tributary Lines	528,218	529,956	0	0.00%
14	334.00	Field Meas. & Reg. Sta. Equip	198,469	198,469	0	0.00%
15	336.00	Purification Equipment	44,369	0	0	0.00%
16						
17		Total Natural Gas Production Plant	907,486	779,080	0	
18						
19		Storage Plant				
20	350.10	Land	261,127	0	0	0.00%
21	350.20	Rights of Way	4,682	4,693	0	0.92%
22	351.00	Sturctures & Improvements	4,700	1,672	90	1.93%
23	351.02	Compression Station Equipment	159,811	116,065	3,049	1.93%
24	351.03	Meas. & Reg. Sta. Structues	23,138	23,985	0	1.93%
25	351.04	Other Structures	144,554	130,830	2,758	1.93%
26	352.00	Wells \ Rights of Way	62,814	35,633	1,683	2.71%
27	352.01	Well Construction	2,113,527	1,740,512	56,616	2.71%
28	352.02	Well Equipment	531,954	557,582	0	2.71%
29	352.03	Cushion Gas	1,694,833	15,237	0	0.00%
30	352.10	Leaseholds	178,530	178,764	0	0.30%
31	352.11	Storage Rights	54,614	51,150	988	1.83%
32	353.01	Field Lines	178,501	183,071	0	1.35%
33	353.02	Tributary Lines	209,458	214,822	0	1.35%
34	354.00	Compressor Station Equipment	546,780	474,740	8,161	1.51%
35	355.00	Meas & Reg. Equipment	288,851	286,074	5,882	2.06%
36	356.00	Purification Equipment	243,119	244,496	0	1.30%
37						
38			6,700,993	4,259,326	79,226	

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account, KY only
Base Period Ended March 31, 2007

FR 10(10)(b)3.2
Schedule B-3.2

Witness: Tom Petersen

Data: _X_ Base Period ___ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).: ______________

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 month average Investment (D)	Reserve (E)	12 Month Expense (F)	Annual Accrual Rate (G)
		Transmission Plant				
1	365.10	Land	26,970	16	0	0.00%
2	365.20	Rights of Way	826,223	331,377	7,269	0.89%
3	366.02	Structures & Improvements	214,065	13,509	2,941	1.39%
4	366.03	Other Structues	69,172	60,525	950	1.39%
5	367.00	Mains - Cathodic Protection	405,764	260,717	5,094	1.27%
6	367.01	Mains - Steel	21,799,664	15,275,907	273,664	1.27%
7	369.00	Meas. & Reg. Equipment	185,854	40,893	4,189	2.28%
8	369.10	Meas. & Reg. Equipment	2,786,961	1,907,875	62,810	2.28%
9						
10		Total Transmission Plant	26,314,674	17,890,819	356,917	
11						
12		Distribution Plant				
13	374.00	Land & Land Rights	94,855	57,145	0	0.00%
14	374.01	Land	51,571	0	0	0.00%
15	374.02	Land Rights	229,318	22,177	3,808	1.68%
16	374.03	Land Other	2,784	0	0	0.00%
17	375.00	Structures & Improvements	312,033	25,754	6,015	1.95%
18	375.01	Structures & Improvements T. B.	105,699	79,141	2,037	1.95%
19	375.02	Land Rights	46,591	37,611	898	1.95%
20	375.03	Improvements	4,005	176	77	1.95%
21	376.00	Mains Cathodic Protection	10,029,188	1,842,869	236,935	2.39%
22	376.01	Mains - Steel	64,078,064	38,182,268	1,513,812	2.39%
23	376.02	Mains Plastic	25,597,506	7,946,520	604,728	2.39%
24	378.00	Meas. & Reg. Sta. Equipment General	2,925,747	1,394,519	72,011	2.49%
25	379.00	Meas. & Reg. Sta. Equipment City Gate	1,250,157	126,649	31,759	2.57%
26	379.05	Meas. & Reg. Sta. Equipment - T. B.	1,636,212	1,196,831	41,566	2.57%
27	380.00	Services	74,128,815	36,113,921	5,026,619	6.86%
28	381.00	Meters	13,888,851	1,301,791	459,913	3.35%
29	382.00	Meter Installations	34,727,743	5,646,466	1,050,420	3.06%
30	383.00	House Regulators	5,043,023	2,561,379	142,069	2.85%
31	384.00	House Reg. Installations	154,276	96,824	5,139	3.37%
32	385.00	Ind. Meas. & Reg. Sta. Equipment	4,590,362	2,021,690	123,872	2.73%
33	386.00	Other Property on Cust. Prem.	2,627	1,815	78	3.00%
34						
35		Total Distribution Plant	238,899,427	98,655,544	9,321,757	

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account, KY only
Base Period Ended March 31, 2007

FR 10(10)(b)3.2
Schedule B-3.2
Page 6 of 12
Witness: Tom Petersen

Data: _X_ Base Period ___ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).: ______________

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 month average Investment (D)	Reserve (E)	12 Month Expense (F)	Annual Accrual Rate (G)
1		General Plant				
2	389.00	Land & Land Rights	70,900	28,459	0	0.00%
3	390.01	Structures Frame	0	0	0	0.00%
4	390.02	Structures & Improvements	191,839	96,981	4,020	2.12%
5	390.03	Improvements	774,269	84,269	16,225	2.12%
6	390.04	Air Conditioning Equipment	11,766	5,078	247	2.12%
7	390.09	Improvement to Leased Premises	1,382,343	1,097,934	68,320	5.00%
8	391.00	Office Furniture & Equipment	1,757,030	656,839	122,443	7.05%
9	391.02	Remittance Processing Equip	0	0	0	0.00%
10	391.03	Office Machines	95,215	(28,147)	6,635	7.05%
11	392.00	Transportation Equipment	545,894	(668,624)	48,132	8.92%
12	392.01	Trucks	24,653	30,218	0	8.92%
13	392.02	Trailers	122,165	122,848	0	8.92%
14	393.00	Stores Equipment	0	0	0	0.00%
15	394.00	Tools, Shop & Garage Equipment	1,620,825	181,478	52,550	3.28%
16	396.00	Power Operated Equipment	0	0	0	0.00%
17	396.03	Ditchers	247,306	(139,338)	6,820	2.79%
18	396.04	Backhoes	278,287	15,074	7,675	2.79%
19	396.05	Welders	43,558	2,846	1,201	2.79%
20	397.00	Communication Equipment	1,141,094	628,057	58,766	5.21%
21	397.01	Communication Equipment - Mobile Radios	3,338	(18,930)	172	5.21%
22	397.02	Communication Equip. - Fixed Radios	41,432	6,084	2,134	5.21%
23	397.05	Communication Equip. - Telemetering	312,236	86,204	16,080	5.21%
24	398.00	Miscellaneous Equipment	2,433,983	852,018	263,208	10.94%
25	399.00	Other Tangible Property	0	0	0	0.00%
26	399.01	Other Tangible Property - Servers - H/W	175,990	181,171	0	14.29%
27	399.02	Other Tangible Property - Servers - S/W	113,473	122,827	0	14.29%
28	399.03	Other Tangible Property - Network Hardware	511,781	477,791	72,291	14.29%
29	399.04	Other Tangible Property - CPU	0	0	0	0.00%
30	399.05	Other Tangible Property - MF Hardware	0	0	0	0.00%
31	399.06	Other Tangible Property - PC Hardware	2,920,797	2,896,164	534,408	18.51%
32	399.07	Other Tang. Property - PC Software	242,979	197,633	38,068	15.85%
33	399.08	Other Tang. Property - Application Software	522,254	365,271	64,529	12.50%
34	399.09	Other Tangible Property - Mainframe S/W	0	0	0	0.00%
35	399.24	Other Tang. Property - General Startup Costs	0	0	0	0.00%
36						
37						
38		Total General Plant	15,585,408	7,280,203	1,383,925	
39						
40		Total Plant	288,536,170	128,993,155	11,141,825	

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account, Div 002 only
Base Period Ended March 31, 2007

FR 10(10)(b)3.2
Data: _X_ Base Period ___ Forecasted Period | Schedule B-3.2
Type of Filing: _X_ Original ___ Updated ___ Revised | Page 7 of 12
Workpaper Reference No(s).: ______________ | Witness: Tom Petersen

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 month average Investment (D)	Reserve (E)	12 Month Expense (F)	Annual Accrual Rate (G)
1		General Plant				
2	389.00	Land & Land Rights	0	0	0	0.00%
3	390.01	Structures Frame	0	0	0	0.00%
4	390.02	Structures & Improvements	0	0	0	0.00%
5	390.03	Improvements	0	0	0	0.00%
6	390.04	Air Conditioning Equipment	0	0	0	0.00%
7	390.09	Improvement to Leased Premises	7,084,974	5,204,140	525,972	7.43%
8	391.00	Office Furniture & Equipment	9,233,165	6,148,467	451,123	4.89%
9	391.02	Remittance Processing Equip	28,932	35,605	0	11.37%
10	391.03	Office Machines	528,284	534,295	0	2.22%
11	392.00	Transportation Equipment	18,885	28,035	0	28.96%
12	392.01	Trucks	0	0	0	0.00%
13	392.02	Trailers	0	0	0	0.00%
14	393.00	Stores Equipment	2,635	3,647	0	10.00%
15	394.00	Tools, Shop & Garage Equipment	10,901	13,151	0	10.00%
16	396.00	Power Operated Equipment	0	0	0	0.00%
17	396.03	Ditchers	0	0	0	0.00%
18	396.04	Backhoes	0	0	0	0.00%
19	396.05	Welders	0	0	0	0.00%
20	397.00	Communication Equipment	2,074,923	814,126	147,611	7.12%
21	397.01	Communication Equipment - Mobile Radios	0	0	0	0.00%
22	397.02	Communication Equip. - Fixed Radios	0	0	0	0.00%
23	397.05	Communication Equip. - Telemetering	0	0	0	0.00%
24	398.00	Miscellaneous Equipment	631,550	379,632	33,823	5.36%
25	399.00	Other Tangible Property	10,196	9,746	1,605	15.75%
26	399.01	Other Tangible Property - Servers - H/W	5,148,574	1,510,125	735,114	14.29%
27	399.02	Other Tangible Property - Servers - S/W	1,821,396	570,659	260,059	14.29%
28	399.03	Other Tangible Property - Network Hardware	1,870,898	335,811	267,127	14.29%
29	399.04	Other Tangible Property - CPU	1,095,465	1,180,547	0	26.26%
30	399.05	Other Tangible Property - MF Hardware	1,159,964	1,218,543	0	15.76%
31	399.06	Other Tangible Property - PC Hardware	4,896,338	3,463,330	823,362	16.83%
32	399.07	Other Tang. Property - PC Software	1,442,733	921,253	255,582	17.73%
33	399.08	Other Tang. Property - Application Software	39,469,010	17,538,527	3,241,629	8.22%
34	399.09	Other Tangible Property - Mainframe S/W	2,583,281	2,853,465	0	22.16%
35	399.24	Other Tang. Property - General Startup Costs	0	0	0	8.33%
36						
37						
38		Total General Plant	79,112,106	42,763,104	6,743,004	
39						
40		Total Plant	79,112,106	42,763,104	6,743,004	

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account, Div 12 only
Base Period Ended March 31, 2007

FR 10(10)(b)3.2
Schedule B-3.2
Page 8 of 12
Witness: Tom Petersen

Data: _X_ Base Period ___ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).: ______________

			Total Company Adjusted Jurisdiction			Annual
			13 month average		12 Month	Accrual
Line No. (A)	Acct. No. (B)	Account Titles (C)	Investment (D)	Reserve (E)	Expense (F)	Rate (G)
1		General Plant				
2	389.00	Land & Land Rights	0	0	0	0.00%
3	390.01	Structures Frame	0	0	0	0.00%
4	390.02	Structures & Improvements	0	0	0	0.00%
5	390.03	Improvements	0	0	0	0.00%
6	390.04	Air Conditioning Equipment	0	0	0	0.00%
7	390.09	Improvement to Leased Premises	3,018,160	1,242,647	224,249	7.43%
8	391.00	Office Furniture & Equipment	56,077	9,312	2,742	4.89%
9	391.02	Remittance Processing Equip	0	0	0	11.37%
10	391.03	Office Machines	0	0	0	2.22%
11	392.00	Transportation Equipment	0	0	0	28.96%
12	392.01	Trucks	0	0	0	0.00%
13	392.02	Trailers	0	0	0	0.00%
14	393.00	Stores Equipment	0	0	0	10.00%
15	394.00	Tools, Shop & Garage Equipment	0	0	0	10.00%
16	396.00	Power Operated Equipment	0	0	0	0.00%
17	396.03	Ditchers	0	0	0	0.00%
18	396.04	Backhoes	0	0	0	0.00%
19	396.05	Welders	0	0	0	0.00%
20	397.00	Communication Equipment	23,362,661	7,170,767	1,663,421	7.12%
21	397.01	Communication Equipment - Mobile Radios	0	0	0	0.00%
22	397.02	Communication Equip. - Fixed Radios	0	0	0	0.00%
23	397.05	Communication Equip. - Telemetering	0	0	0	0.00%
24	398.00	Miscellaneous Equipment	1,916	275	103	5.36%
25	399.00	Other Tangible Property	214,670	205,213	33,811	15.75%
26	399.01	Other Tangible Property - Servers - H/W	9,856,698	7,314,911	1,408,522	14.29%
27	399.02	Other Tangible Property - Servers - S/W	6,859,702	5,896,027	980,251	14.29%
28	399.03	Other Tangible Property - Network Hardware	459,783	193,973	65,703	14.29%
29	399.04	Other Tangible Property - CPU	0	0	0	26.26%
30	399.05	Other Tangible Property - MF Hardware	0	0	0	15.76%
31	399.06	Other Tangible Property - PC Hardware	3,265,781	1,168,836	549,631	16.83%
32	399.07	Other Tang. Property - PC Software	2,355,544	1,128,273	417,638	17.73%
33	399.08	Other Tang. Property - Application Software	73,886,455	32,747,763	6,073,467	8.22%
34	399.09	Other Tangible Property - Mainframe S/W	0	0	0	22.16%
35	399.24	Other Tang. Property - General Startup Costs	23,172,326	13,952,692	1,930,255	8.33%
36						
37						
38		Total General Plant	146,509,773	71,030,689	13,349,793	
39						
40		Total Plant	146,509,773	71,030,689	13,349,793	

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account, Div 91 only
Base Period Ended March 31, 2007

FR 10(10)(b)3.2
Schedule B-3.2

Witness: Tom Petersen

Data: _X_ Base Period ___ Forecasted Period
Type of Filing: ___ Original ___ Updated _X_ Revised
Workpaper Reference No(s).: _______________

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 month average Investment (D)	Reserve (E)	12 Month Expense (F)	Annual Accrual Rate (G)
1		Intangible Plant				
2	301.00	Organization	185,309	0	0	0.00%
3	302.00	Franchises & Consents	0	0	0	0.00%
4	303.00	Misc. Intangible Plant	1,109,552	0	0	0.00%
5						
6		Total Intangible Plant	1,294,861	0	0	
7						
8		Distribution Plant				
9	376.01	Mains - Steel	0	0	0	3.61%
10						
11		Total Distribution Plant	0	0	0	
12						
13		General Plant				
14	389.00	Land & Land Rights	0	0	0	0.00%
15	390.01	Structures Frame	179,339	17,253	4,473	2.52%
16	390.02	Structures & Improvements	0	0	0	0.00%
17	390.03	Improvements	0	0	0	0.00%
18	390.04	Air Conditioning Equipment	5,771	5,810	0	2.52%
19	390.09	Improvement to Leased Premises	38,834	49,348	0	2.52%
20	391.00	Office Furniture & Equipment	1,273,200	1,278,077	0	5.69%
21	391.02	Remittance Processing Equip	0	0	0	0.00%
22	391.03	Office Machines	41,158	31,094	2,318	5.69%
23	392.00	Transportation Equipment	9,235	13,953	0	0.00%
24	392.01	Trucks	0	0	0	0.00%
25	392.02	Trailers	0	0	0	0.00%
26	393.00	Stores Equipment	10,698	7,552	757	7.15%
27	394.00	Tools, Shop & Garage Equipment	127,345	25,132	5,066	4.02%
28	396.00	Power Operated Equipment	8,497	8,724	0	11.11%
29	396.03	Ditchers	0	0	0	0.00%
30	396.04	Backhoes	0	0	0	0.00%
31	396.05	Welders	0	0	0	0.00%
32	397.00	Communication Equipment	251,835	109,928	18,668	7.49%
33	397.01	Communication Equipment - Mobile Radios	0	0	0	0.00%
34	397.02	Communication Equip. - Fixed Radios	0	0	0	0.00%
35	397.05	Communication Equip. - Telemetering	0	0	0	0.00%
36	398.00	Miscellaneous Equipment	646,215	130,640	28,140	4.40%
37	399.00	Other Tangible Property	76,993	52,810	14,462	18.98%
38	399.01	Other Tangible Property - Servers - H/W	71,663	59,781	10,135	14.29%
39	399.02	Other Tangible Property - Servers - S/W	8,273	11,836	0	14.29%
40	399.03	Other Tangible Property - Network Hardware	229,003	193,677	32,387	14.29%
41	399.04	Other Tangible Property - CPU	0	0	0	0.00%
42	399.05	Other Tangible Property - MF Hardware	0	0	0	0.00%
43	399.06	Other Tangible Property - PC Hardware	1,235,175	471,267	232,015	18.98%
44	399.07	Other Tang. Property - PC Software	98,204	103,222	0	18.98%
45	399.08	Other Tang. Property - Application Software	741,652	1,820,313	0	18.98%
46	399.09	Other Tangible Property - Mainframe S/W	0	0	0	0.00%
47	399.24	Other Tang. Property - General Startup Costs	0	0	0	0.00%
48		Total General Plant	5,053,090	4,390,417	348,420	
49		Total Plant	6,347,951	4,390,417	348,420	

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account
Forecasted Period ended June 30, 2008

FR 10(10)(b)3.2
Schedule B-3.2
Page 10 of 12
Witness: Tom Petersen

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 Month Avg. Investment (D)	Reserve (E)	12 Month Expense (F)	Annual Accrual Rate (G)
1		Intangible Plant				See Note
2	301.00	Organization	76,480	8,330	0	
3	302.00	Franchises & Consents	119,853	119,853	0	
4	303.00	Misc. Intangible Plant	408,053	0	0	
5						
6		Total Intangible Plant	604,386	128,182	0	
7						
8		Natural Gas Production Plant				
9	325.20	Producing Leaseholds	2,353	69	137	
10	325.40	Rights of Ways	83,422	955	1,888	
11	331.00	Production Gas Wells Equipment	3,492	3,492	0	
12	332.01	Field Lines	47,163	47,163	0	
13	332.02	Tributary Lines	528,218	529,956	0	
14	334.00	Field Meas. & Reg. Sta. Equip	198,469	198,469	0	
15	336.00	Purification Equipment	44,369	1,167	2,307	
16						
17		Total Natural Gas Production Plant	907,486	781,271	4,332	
18						
19		Storage Plant				
20	350.10	Land	261,127	0	0	
21	350.20	Rights of Way	4,682	4,757	0	
22	351.00	Structures & Improvements	4,700	2,503	28	
23	351.02	Compression Station Equipment	159,811	118,199	948	
24	351.03	Meas. & Reg. Sta. Structues	23,138	25,129	0	
25	351.04	Other Structures	144,554	132,962	857	
26	352.00	Wells \ Rights of Way	62,814	51,466	1,310	
27	352.01	Well Construction	2,113,527	1,795,052	44,081	
28	352.02	Well Equipment	531,954	583,481	0	
29	352.03	Cushion Gas	1,694,833	43,472	39,872	
30	352.10	Leaseholds	178,530	179,464	0	
31	352.11	Storage Rights	54,614	52,586	238	
32	353.01	Field Lines	178,501	186,188	0	
33	353.02	Tributary Lines	209,458	219,495	0	
34	354.00	Compressor Station Equipment	546,780	481,599	3,243	
35	355.00	Meas & Reg. Equipment	288,851	290,474	0	
36	356.00	Purification Equipment	243,119	248,386	0	
37						
38		Total Storage Plant	6,700,993	4,415,212	90,577	

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account
Forecasted Period ended June 30, 2008

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).

FR 10(10)(b)3.2
Schedule B-3.2

Witness: Tom Petersen

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 Month Avg. Investment (D)	13 Month Avg. Reserve (E)	12 Month Expense (F)	
		Transmission Plant				See Note
1	365.10	Land	26,970	16	0	
2	365.20	Rights of Way	838,245	342,444	13,672	
3	366.02	Structures & Improvements	214,065	17,431	4,338	
4	366.03	Other Structues	69,172	63,126	1,402	
5	367.00	Mains - Cathodic Protection	406,111	338,041	7,426	
6	367.01	Mains - Steel	23,217,765	15,630,914	424,577	
7	369.00	Meas. & Reg. Equipment	185,854	60,681	2,719	
8	369.01	Meas. & Reg. Equipment	2,968,370	1,961,721	43,425	
9						
10		Total Transmission Plant	27,926,553	18,414,372	497,559	
11						
12		Distribution Plant				
13	374.00	Land & Land Rights	98,315	57,145	0	
14	374.01	Land	51,571	0	0	
15	374.02	Land Rights	244,565	26,362	4,496	
16	374.03	Land Other	2,784	0	0	
17	375.00	Structures & Improvements	312,033	34,273	9,808	
18	375.01	Structures & Improvements T.B.	105,699	82,079	3,322	
19	375.02	Land Rights	46,591	38,826	1,465	
20	375.03	Improvements	4,005	51,331	0	
21	376.00	Mains Cathodic Protection	10,874,159	2,492,227	261,196	
22	376.01	Mains - Steel	68,360,296	39,831,667	1,642,007	
23	376.02	Mains - Plastic	27,804,905	8,618,209	667,871	
24	378.00	Meas. & Reg. Sta. Equip - General	3,132,686	1,442,340	59,454	
25	379.00	Meas. & Reg. Sta. Equipment - City Gate	1,277,515	168,827	30,686	
26	379.05	Meas & Reg. Sta. Equipment T.B.	1,636,212	1,730,200	0	
27	380.00	Services	79,748,813	39,569,257	4,122,785	
28	381.00	Meters	14,802,451	2,527,504	1,179,325	
29	382.00	Meter Installations	36,781,828	6,843,967	1,672,461	
30	383.00	House Regulators	5,400,323	2,713,334	154,804	
31	384.00	House Reg. Installations	154,276	140,951	3,080	
32	385.00	Ind. Meas. & Reg. Sta. Equipment	4,926,403	2,148,899	127,097	
33	386.00	Other Property on Cust Prem	0	2,511	0	
34						
35		Total Distribution Plant	255,765,430	108,519,908	9,939,858	

Atmos Energy Corporation, KY
Case No. 2006-00464
Jurisdictional Depreciation Expense, Accum. Reserve & Accrual Rates by Account
Forecasted Period ended June 30, 2008

FR 10(10)(b)3.2
Schedule B-3.2
Page 12 of 12
Witness: Tom Petersen

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(s).

Line No. (A)	Acct. No. (B)	Account Titles (C)	Total Company Adjusted Jurisdiction 13 Month Avg. Investment (D)	13 Month Avg. Reserve (E)	12 Month Expense (F)	
1		General Plant *				See Note
2	389.00	Land & Land Rights	71,393	28,459	0	
3	390.01	Structures Frame	65,954	8,423	1,645	
4	390.02	Structures & Improvements	193,598	109,629	18,964	
5	390.03	Improvements	774,269	134,945	75,846	
6	390.04	Air Conditioning Equipment	14,251	8,084	1,188	
7	390.09	Improvement to Leased Premises	1,939,014	1,571,253	81,576	
8	391.00	Office Furniture & Equipment	2,496,243	1,425,957	105,852	
9	391.02	Remittance Processing Equip	956	1,551	0	
10	391.03	Office Machines	119,984	4,045	6,500	
11	392.00	Transportation Equipment	509,135	(509,844)	304,276	
12	392.01	Trucks	16,597	25,470	0	
13	392.02	Trailers	111,671	154,672	0	
14	393.00	Stores Equipment	3,856	3,119	278	
15	394.00	Tools, Shop & Garage Equip	1,449,163	72,973	93,816	
16	396.00	Power Operated Equipment	3,125	3,704	0	
17	396.03	Ditchers	223,756	(133,021)	45,916	
18	396.04	Backhoes	267,602	38,654	54,914	
19	396.05	Welders	33,959	(1,713)	6,969	
20	397.00	Communication Equipment	2,653,181	1,297,724	187,921	
21	397.01	Communication Equip. - Mobile Radios	3,338	(18,709)	179	
22	397.02	Communication Equip. - Fixed Radios	41,432	8,828	2,224	
23	397.05	Communication Equip. - Telemetering	312,236	106,882	16,759	
24	398.00	Miscellaneous Equipment	2,850,542	1,192,768	121,768	
25	399.00	Other Tangible Property	40,867	39,927	5,319	
26	399.01	Other Tangible Property - Servers - H/W	1,255,886	852,243	73,192	
27	399.02	Other Tangible Property - Servers - S/W	603,296	573,183	19,468	
28	399.03	Other Tangible Property - Network - H/W	724,910	680,115	24,059	
29	399.04	Other Tangible Property - CPU	56,964	83,539	0	
30	399.05	Other Tangible Property - MF Hardware	60,318	77,441	0	
31	399.06	Other Tangible Property - PC Hardware	4,538,528	3,909,152	177,992	
32	399.07	Other Tang. Property - PC Software	515,241	447,639	21,295	
33	399.08	Other Tang. Property - Application Software	7,610,511	4,689,742	845,902	
34	399.09	Other Tang. Property - Mainframe S/W	133,816	191,807	0	
35	399.24	Other Tang. Property - General Startup Costs	1,297,650	964,881	206,197	
36						
37		Total General Plant	30,993,244	18,043,519	2,500,016	
38						
39		Total Plant	322,898,092	150,302,465	13,032,342	

*** Note: Includes allocations from Shared Services and Mid States General office.**

Column G Note: Depreciation rates are specific to Kentucky, Shared Services amd Mid States General office and can be found on schedules wpB.3.2 F series of schedules.

Atmos Energy Corporation, KY
Case No. 2006-00464
workpaper Computation of Depreciation Expense - Div. 09 KY Only
Forecast Period Ending 6-30-2008

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: ___ Original ___ Updated _X_ Revised
Workpaper Reference No(S).: _____________

WP Sched. B-3.2
Page 7 of 9
Witness:

Line No. (A)	Acct. No. (B)	Account Titles (C)	DIVISION 09 13 Month Avg. Investment (D)	Reserve (E)	Annual Accrual Rate Projected (G)	Reserve Computation	12 Month Expense 98.85% (F)
1		Intangible Plant					
2	301.00	Organization	8,330	8,330	0.00%	0	0
3	302.00	Franchises & Consents	119,853	119,853	5.00%	0	0
4	303.00	Misc. Intangible Plant	0	0	0.00%	0	0
5							
6		Total Intangible Plant	128,182	128,182		0	0
7							
8		Natural Gas Production Plant					
9	325.20	Producing Leaseholds	2,353	69	5.89%	139	137
10	325.40	Rights of Ways	83,422	955	2.29%	1,910	1,888
11	331.00	Production Gas Wells Equipment	3,492	3,492	0.00%	0	0
12	332.01	Field Lines	47,163	47,163	0.00%	0	0
13	332.02	Tributary Lines	528,218	529,956	0.00%	0	0
14	334.00	Field Meas. & Reg. Sta. Equip	198,469	198,469	0.00%	0	0
15	336.00	Purification Equipment	44,369	1,167	5.26%	2,334	2,307
16							
17		Total Natural Gas Production Plant	907,486	781,271		4,383	4,332
18							
19		Storage Plant					
20	350.10	Land	261,127	0	0.00%	0	0
21	350.20	Rights of Way	4,682	4,757	0.92%	0	0
22	351.00	Structures & Improvements	4,700	2,503	0.60%	28	28
23	351.02	Compression Station Equipment	159,811	118,199	0.60%	959	948
24	351.03	Meas. & Reg. Sta. Structues	23,138	25,129	1.93%	0	0
25	351.04	Other Structures	144,554	132,962	0.60%	867	857
26	352.00	Wells \ Rights of Way	62,814	51,466	2.11%	1,325	1,310
27	352.01	Well Construction	2,113,527	1,795,052	2.11%	44,595	44,081
28	352.02	Well Equipment	531,954	583,481	2.71%	0	0
29	352.03	Cushion Gas	1,694,833	43,472	2.38%	40,337	39,872
30	352.10	Leaseholds	178,530	179,464	0.30%	0	0
31	352.11	Storage Rights	54,614	52,586	0.44%	240	238
32	353.01	Field Lines	178,501	186,188	1.35%	0	0
33	353.02	Tributary Lines	209,458	219,495	1.35%	0	0
34	354.00	Compressor Station Equipment	546,780	481,599	0.60%	3,281	3,243
35	355.00	Meas & Reg. Equipment	288,851	290,474	0.12%	0	0
36	356.00	Purification Equipment	243,119	248,386	1.30%	0	0
37							
38		Total Storage Plant	6,700,993	4,415,212		91,633	90,577

Atmos Energy Corporation, KY
Case No. 2006-00464
workpaper Computation of Depreciation Expense - Div. 09 KY Only
Forecast Period Ending 6-30-2008

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: ___ Original ___ Updated _X_ Revised
Workpaper Reference No(S).: ____________

Line No. (A)	Acct. No. (B)	Account Titles (C)	DIVISION 09 13 Month Avg. Investment (D)	Reserve (E)	Annual Accrual Rate (G)	Reserve Computation	12 Month Expense (F)
		Transmission Plant					
1	365.10	Land	26,970	16	0.00%	0	0
2	365.20	Rights of Way	838,245	342,444	1.65%	13,831	13,672
3	366.02	Structures & Improvements	214,065	17,431	2.05%	4,388	4,338
4	366.03	Other Structues	69,172	63,126	2.05%	1,418	1,402
5	367.00	Mains - Cathodic Protection	406,111	338,041	1.85%	7,513	7,426
6	367.01	Mains - Steel	23,217,765	15,630,914	1.85%	429,529	424,577
7	369.00	Meas. & Reg. Equipment	185,854	60,681	1.48%	2,751	2,719
8	369.01	Meas. & Reg. Equipment	2,968,370	1,961,721	1.48%	43,932	43,425
9							
10		Total Transmission Plant	27,926,553	18,414,372		503,362	497,559
11							
12		Distribution Plant					
13	374.00	Land & Land Rights	98,315	57,145	0.00%	0	0
14	374.01	Land	51,571	0	0.00%	0	0
15	374.02	Land Rights	244,565	26,362	1.86%	4,549	4,496
16	374.03	Land Other	2,784	0	0.00%	0	0
17	375.00	Structures & Improvements	312,033	34,273	3.18%	9,923	9,808
18	375.01	Structures & Improvements T.B.	105,699	82,079	3.18%	3,361	3,322
19	375.02	Land Rights	46,591	38,826	3.18%	1,482	1,465
20	375.03	Improvements	4,005	51,331	3.18%	0	0
21	376.00	Mains Cathodic Protection	10,874,159	2,492,227	2.43%	264,242	261,196
22	376.01	Mains - Steel	68,360,296	39,831,667	2.43%	1,661,155	1,642,007
23	376.02	Mains - Plastic	27,804,905	8,618,209	2.43%	675,659	667,871
24	378.00	Meas. & Reg. Sta. Equipment General	3,132,686	1,442,340	1.92%	60,148	59,454
25	379.00	Meas. & Reg. Sta. Equipment - City Gate	1,277,515	168,827	2.43%	31,044	30,686
26	379.05	Meas & Reg. Sta. Equipment T.B.	1,636,212	1,730,200	2.43%	0	0
27	380.00	Services	79,748,813	39,569,257	5.23%	4,170,863	4,122,785
28	381.00	Meters	14,802,451	2,527,504	8.06%	1,193,078	1,179,325
29	382.00	Meter Installations	36,781,828	6,843,967	4.60%	1,691,964	1,672,461
30	383.00	House Regulators	5,400,323	2,713,334	2.90%	156,609	154,804
31	384.00	House Reg. Installations	154,276	140,951	2.02%	3,116	3,080
32	385.00	Ind. Meas. & Reg. Sta. Equipment	4,926,403	2,148,899	2.61%	128,579	127,097
33	386.00	Other Property on Cust Prem	0	2,511	3.00%	0	0
34							
35		Total Plant Distribution	255,765,430	108,519,908		10,055,771	9,939,858

Atmos Energy Corporation, KY
Case No. 2006-00464
workpaper Computation of Depreciation Expense - Div. 09 KY Only
Forecast Period Ending 6-30-2008

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: ___ Original ___ Updated _X_ Revised
Workpaper Reference No(S).: ______________

Line No. (A)	Acct. No. (B)	Account Titles (C)	DIVISION 09 13 Month Avg. Investment (D)	DIVISION 09 13 Month Avg. Reserve (E)	Annual Accrual Rate (G)	Reserve Computation	12 Month Expense (F)
		General Plant					
1	389.00	Land & Land Rights	71,393	28,459	0.00%	0	0
2	390.01	Structures Frame	0	0		0	0
3	390.02	Structures & Improvements	193,598	109,629	9.91%	19,186	18,964
4	390.03	Improvements	774,269	134,945	9.91%	76,730	75,846
5	390.04	Air Conditioning Equipment	12,129	5,868	9.91%	1,202	1,188
6	390.09	Improvement to Leased Premises	1,382,343	1,166,083	2.36%	32,623	32,247
7	391.00	Office Furniture & Equipment	1,560,722	603,410	6.22%	97,077	95,958
8	391.02	Remittance Processing Equip	0	0		0	0
9	391.03	Office Machines	94,911	(20,448)	6.22%	5,903	5,835
10	392.00	Transportation Equipment	514,843	(507,588)	59.79%	307,825	304,276
11	392.01	Trucks	16,597	25,470	8.92%	0	0
12	392.02	Trailers	111,671	154,672	59.79%	0	0
13	393.00	Stores Equipment	0	0		0	0
14	394.00	Tools, Shop & Garage Equip	1,404,373	63,134	6.63%	93,110	92,037
15	396.00	Power Operated Equipment	0	0		0	0
16	396.03	Ditchers	223,756	(133,021)	20.76%	46,452	45,916
17	396.04	Backhoes	267,602	38,654	20.76%	55,554	54,914
18	396.05	Welders	33,959	(1,713)	20.76%	7,050	6,969
19	397.00	Communication Equipment	1,141,094	703,626	5.43%	61,961	61,247
20	397.01	Communication Equip. - Mobile Radios	3,338	(18,709)	5.43%	181	179
21	397.02	Communication Equip. - Fixed Radios	41,432	8,828	5.43%	2,250	2,224
22	397.05	Communication Equip. - Telemetering	312,236	106,882	5.43%	16,954	16,759
23	398.00	Miscellaneous Equipment	2,511,890	1,107,139	4.26%	107,006	105,773
24	399.00	Other Tangible Property	0	0		0	0
25	399.01	Other Tangible Property - Servers - H/W	175,990	205,672	2.71%	0	0
26	399.02	Other Tangible Property - Servers - S/W	113,473	146,838	14.29%	0	0
27	399.03	Other Tangible Property - Network - H/W	511,781	545,999	5.22%	0	0
28	399.04	Other Tangible Property - CPU	0	0		0	0
29	399.05	Other Tangible Property - MF Hardware	0	0		0	0
30	399.06	Other Tangible Property - PC Hardware	3,631,797	3,410,816	0.61%	22,154	21,899
31	399.07	Other Tang. Property - PC Software	242,979	249,794	19.16%	0	0
32	399.08	Other Tang. Property - Application Software	522,254	459,904	17.49%	91,342	90,289
33	399.09	Other Tangible Property - Mainframe - S/W	0	0	0.00%	0	0
34	399.24	Other Tang. Property - General Startup Costs	0	0	0.00%	0	0
35							
36		Total General Plant	15,870,429	8,594,342		1,044,561	1,032,520
37							
38		Total Plant	307,299,074	140,853,287		11,699,710	11,564,847

Atmos Energy Corporation, KY
Case No. 2006-00464
workpaper Computation of Depreciation Expense - Div. 02 General Office only
Forecast Period Ending 6-30-2008

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: ___ Original ___ Updated _X_ Revised
Workpaper Reference No(S).: _____________

WP Sched. B-3.2
Page 1 of 2
Witness:

Line No.	Acct. No.	Account Titles	DIVISION 02 13 Month Avg. Investment	Reserve	Annual Accrual Rate Projected	Reserve Computation	12 Month Expense 99.92%
(A)	(B)	(C)	(D)	(E)	(G)		(F)
		General Plant					
1	389.00	Land & Land Rights	0	0	0.00%	0	0
2	390.01	Structures Frame	0	0	0.00%	0	0
3	390.02	Structures & Improvements	0	0	0.00%	0	0
4	390.03	Improvements	0	0	0.00%	0	0
5	390.04	Air Conditioning Equipment	0	0	0.00%	0	0
6	390.09	Improvement to Leased Premises	7,180,234	5,759,267	9.10%	653,401	652,853
7	391.00	Office Furniture & Equipment	8,880,324	6,072,967	2.13%	189,151	188,992
8	391.02	Remittance Processing Equip	18,384	29,821	11.37%	0	0
9	391.03	Office Machines	255,134	292,550	2.22%	0	0
10	392.00	Transportation Equipment	18,885	36,133	28.96%	0	0
11	392.01	Trucks	0	0	0.00%	0	0
12	392.02	Trailers	0	0	0.00%	0	0
13	393.00	Stores Equipment	(1,516)	(188)	10.00%	0	0
14	394.00	Tools, Shop & Garage Equip	1,343	5,198	10.00%	0	0
15	396.00	Power Operated Equipment	0	0	0.00%	0	0
16	396.03	Ditchers	0	0	0.00%	0	0
17	396.04	Backhoes	0	0	0.00%	0	0
18	396.05	Welders	0	0	0.00%	0	0
19	397.00	Communication Equipment	990,598	308,482	8.45%	83,705	83,635
20	397.01	Communication Equip. - Mobile Radios	0	0	0.00%	0	0
21	397.02	Communication Equip. - Fixed Radios	0	0	0.00%	0	0
22	397.05	Communication Equip. - Telemetering	0	0	0.00%	0	0
23	398.00	Miscellaneous Equipment	631,550	429,080	8.15%	51,471	51,428
24	399.00	Other Tangible Property	10,196	11,200	4.66%	0	0
25	399.01	Other Tangible Property - Servers - H/W	9,436,183	2,501,386	6.95%	655,815	655,264
26	399.02	Other Tangible Property - Servers - S/W	1,971,595	807,464	4.00%	78,864	78,798
27	399.03	Other Tangible Property - Network - H/W	1,917,244	628,553	9.30%	178,304	178,154
28	399.04	Other Tangible Property - CPU	1,095,465	1,606,519	26.26%	0	0
29	399.05	Other Tangible Property - MF Hardware	1,159,964	1,489,243	15.76%	0	0
30	399.06	Other Tangible Property - PC Hardware	3,086,387	2,272,695	14.86%	458,637	458,252
31	399.07	Other Tang. Property - PC Software	1,467,647	1,170,832	9.02%	132,382	132,271
32	399.08	Other Tang. Property - Application Software	50,421,532	22,467,881	11.11%	5,601,832	5,597,130
33	399.09	Other Tangible Property - Mainframe - S/W	2,573,389	3,688,598	22.16%	0	0
34	399.24	Other Tang. Property - General Startup Costs	0	0	15.89%	0	0
35							
36		Total General Plant	91,114,538	49,577,681		8,083,562	8,076,776
37							
38		Total Plant	91,114,538	49,577,681		8,083,562	8,076,776

Atmos Energy Corporation, KY
Case No. 2006-00464
workpaper Computation of Depreciation Expense - Div 12 Customer Service only
Forecast Period Ending 6-30-2008

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: ___ Original ___ Updated _X_ Revised
Workpaper Reference No(S).: ______________

WP Sched. B-3.2

Witness:

Line No.	Acct. No.	Account Titles	DIVISION 12 13 Month Avg. Investment	DIVISION 12 13 Month Avg. Reserve	Annual Accrual Rate Projected	Reserve Computation	12 Month Expense 100.00%
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		General Plant					
1	389.00	Land & Land Rights	0	0	0.00%	0	0
2	390.01	Structures Frame	0	0	0.00%	0	0
3	390.02	Structures & Improvements	0	0	0.00%	0	0
4	390.03	Improvements	0	0	0.00%	0	0
5	390.04	Air Conditioning Equipment	0	0	0.00%	0	0
6	390.09	Improvement to Leased Premises	3,018,160	1,553,690	9.10%	274,653	274,653
7	391.00	Office Furniture & Equipment	56,077	11,875	2.13%	1,194	1,194
8	391.02	Remittance Processing Equip	0	0	0.00%	0	0
9	391.03	Office Machines	0	0	0.00%	0	0
10	392.00	Transportation Equipment	0	0	0.00%	0	0
11	392.01	Trucks	0	0	0.00%	0	0
12	392.02	Trailers	0	0	0.00%	0	0
13	393.00	Stores Equipment	0	0	0.00%	0	0
14	394.00	Tools, Shop & Garage Equip	0	0	0.00%	0	0
15	396.00	Power Operated Equipment	0	0	0.00%	0	0
16	396.03	Ditchers	0	0	0.00%	0	0
17	396.04	Backhoes	0	0	0.00%	0	0
18	396.05	Welders	0	0	0.00%	0	0
19	397.00	Communication Equipment	24,199,330	9,432,840	8.45%	2,044,843	2,044,843
20	397.01	Communication Equip. - Mobile Radios	0	0	0.00%	0	0
21	397.02	Communication Equip. - Fixed Radios	0	0	0.00%	0	0
22	397.05	Communication Equip. - Telemetering	0	0	0.00%	0	0
23	398.00	Miscellaneous Equipment	1,916	428	8.15%	156	156
24	399.00	Other Tangible Property	214,670	235,803	4.66%	0	0
25	399.01	Other Tangible Property - Servers - H/W	10,051,060	8,746,527	6.95%	698,549	698,549
26	399.02	Other Tangible Property - Servers - S/W	6,861,747	6,774,304	4.00%	274,470	274,470
27	399.03	Other Tangible Property - Network - H/W	459,784	264,431	9.30%	42,760	42,760
28	399.04	Other Tangible Property - CPU	0	0	0.00%	0	0
29	399.05	Other Tangible Property - MF Hardware	0	0	0.00%	0	0
30	399.06	Other Tangible Property - PC Hardware	3,599,489	1,545,069	14.86%	534,884	534,884
31	399.07	Other Tang. Property - PC Software	2,854,096	1,586,604	9.02%	257,439	257,439
32	399.08	Other Tang. Property - Application Software	74,669,220	41,318,325	11.11%	8,295,750	8,295,750
33	399.09	Other Tangible Property - Mainframe - S/W	0	0	0.00%	0	0
34	399.24	Other Tang. Property - General Startup Costs	23,172,326	17,230,016	15.89%	3,682,083	3,682,083
35							
36		Total General Plant	149,157,876	88,699,913		16,106,782	16,106,782
37							
38		Total Plant	149,157,876	88,699,913		16,106,782	16,106,782

Atmos Energy Corporation, KY
Case No. 2006-00464
workpaper Computation of Depreciation Expense - Div. 91 Admin. Office only
Forecast Period Ending 6-30-2008

Data: ___ Base Period _X_ Forecasted Period
Type of Filing: _X_ Original ___ Updated ___ Revised
Workpaper Reference No(S).: _______________

WP Sched. B-3.2
Page 7 of 9
Witness:

Line No.	Acct. No.	Account Titles	DIVISION 91 13 Month Avg. Investment	Reserve	Annual Accrual Rate	Reserve Computation	12 Month Expense 98.97%
(A)	(B)	(C)	(D)	(E)	(G)		(F)
1		Intangible Plant					
2	301.00	Organization	185,309	0	0.00%	0	0
3	302.00	Franchises & Consents	0	0	0.00%	0	0
4	303.00	Misc. Intangible Plant	1,109,552	0	0.00%	0	0
5							
6		Total Intangible Plant	1,294,861	0		0	0
7							
8							
9		Distribution Plant					
10	376.01	Mains - Steel	0	0	3.61%	0	0
11							
12		Total Plant Distribution	0	0		0	0
13							
14		General Plant					
15	389.00	Land & Land Rights	0	0	0.00%	0	0
16	390.01	Structures Frame	179,339	22,902	2.52%	4,519	4,473
17	390.02	Structures & Improvements	0	0	0.00%	0	0
18	390.03	Improvements	0	0	0.00%	0	0
19	390.04	Air Conditioning Equipment	5,771	6,026	2.52%	0	0
20	390.09	Improvement to Leased Premises	38,834	50,798	2.52%	0	0
21	391.00	Office Furniture & Equipment	1,279,638	1,376,122	5.69%	0	0
22	391.02	Remittance Processing Equip	0	0	0.00%	0	0
23	391.03	Office Machines	32,103	25,234	5.69%	1,827	1,808
24	392.00	Transportation Equipment	(18,191)	(11,244)	0.00%	0	0
25	392.01	Trucks	0	0	0.00%	0	0
26	392.02	Trailers	0	0	0.00%	0	0
27	393.00	Stores Equipment	10,698	8,508	7.15%	765	757
28	394.00	Tools, Shop & Garage Equip	121,600	26,017	4.02%	4,888	4,838
29	396.00	Power Operated Equipment	8,497	10,070	11.11%	0	0
30	396.03	Ditchers	0	0	0.00%	0	0
31	396.04	Backhoes	0	0	0.00%	0	0
32	396.05	Welders	0	0	0.00%	0	0
33	397.00	Communication Equipment	286,634	135,459	7.49%	21,469	21,247
34	397.01	Communication Equip. - Mobile Radios	0	0	0.00%	0	0
35	397.02	Communication Equip. - Fixed Radios	0	0	0.00%	0	0
36	397.05	Communication Equip. - Telemetering	0	0	0.00%	0	0
37	398.00	Miscellaneous Equipment	831,253	172,103	4.40%	36,575	36,197
38	399.00	Other Tangible Property	76,993	71,076	18.98%	14,613	14,462
39	399.01	Other Tangible Property - Servers - H/W	71,663	72,581	14.29%	0	0
40	399.02	Other Tangible Property - Servers - S/W	8,273	13,586	14.29%	0	0
41	399.03	Other Tangible Property - Network - H/W	238,424	235,540	14.29%	34,071	33,719
42	399.04	Other Tangible Property - CPU	0	0	0.00%	0	0
43	399.05	Other Tangible Property - MF Hardware	0	0	0.00%	0	0
44	399.06	Other Tangible Property - PC Hardware	1,481,024	798,427	18.98%	281,098	278,196
45	399.07	Other Tang. Property - PC Software	98,204	130,822	18.98%	0	0
46	399.08	Other Tang. Property - Application Software	774,577	2,033,050	18.98%	0	0
47	399.09	Other Tangible Property - Mainframe - S/W	0	0	0.00%	0	0
48	399.24	Other Tang. Property - General Startup Costs	0	0	0.00%	0	0
49							
50		Total General Plant	5,525,332	5,177,079		399,826	395,697
51							
52		Total Plant	6,820,193	5,177,079		399,826	395,697

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 174
Witness: Greg Waller

Data Request:

Please provide the amount of depreciation expense related to the SSU assets and allocated to Kentucky (Waller, p. 17). Also, provide the calculation of those amounts in Excel, with all formulae intact, showing plant balances, depreciation rates, the allocation factor used to allocate the expense to Kentucky, and a description of how that allocation factor is derived.

Response:

The amount of depreciation expense related to the SSU assets and allocated to Kentucky is $1,098,225 for the base period and $1,321,972 for the forecasted test period. These amounts are included in the amounts in Mr. Waller's testimony (page 17).

The depreciation expense related to SSU assets is provided in detail as a response to the previous DR #173.

Please refer to the attachment Case 2006-00464 AG DR1-173 ATT tabs B.3.2 B 02, B.3.2 B 12, wpB.3.2 F 02, and wpB.3.2 F 12. These schedules are sponsored by Tom Petersen as a part of the rate base calculation.

Please see Mr. Cagle's testimony for information regarding the calculation of allocation factors.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 175
Witness: Bernard Uffelman

Data Request:

Please provide a complete electronic copy of Mr. Uffelman's class cost of service study with all internal formulas intact.

Response:

Please see the attached CD labeled AG DR1-175 ATT for a complete copy of the Atmos Energy Corporation Kentucky Division class cost of service study with all internal formulas intact.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 176
Witness: Gary Smith

Data Request:

Were any administrative and general expenses allocated to gas costs for recovery through the GCA mechanism? If so, please describe the method for doing so and the amount allocated.

Response:

No.

ATMOS energy

RECEIVED
MAR 3 0 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.

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
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	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	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

				(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

				(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

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.		(1) Purchases Mcf	(2) Purchases 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							

Line No.	Description	Annualized MDQs in MMbtu	Allocation	Commodity Charge $/MMbtu	Weighted Average
28	Used to allocate transportation non-commodity				
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) 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

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

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

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)	(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, 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	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	2.60 % (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	-	-

- 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

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	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

Line No.	Description	Unit	GL Dec-05 (1) Month November-05	Jan-06 (2) December-05	Feb-06 (3) January-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	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	GL Unit	Dec-05 (1) November-05	Jan-06 (2) Month December-05	Feb-06 (3) January-06	Source Document
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 Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 177
Witness: Greg Waller & Tom Petersen

Data Request:

Please quantify all costs included in the Company's revenue requirement that are associated with gas acquisition, transportation and storage, including G&A costs.

Response:

The following separately identified costs are included in the forecasted revenue requirement:

Gas Supply Services:		$249,598
Gas Control Services:		$193,055
Storage O&M Costs		$262,213
Depreciation Expense:		
	Storage	$90,569
	Production	$4,332

Additionally, the traditional regulatory treatment of gas storage inventory costs recognizes the 13-month average balance as a rate base component. Thus, there are also some return and taxes on investment associated with storage gas facilities:

Storage Plant in Service – Gross $6,700,993 – Accumulated Depreciation $4,415,212

Gas Stored Underground - $21,792,727

Other gas acquisition, transportation and storage costs that are recoverable through the GCA are included in purchased gas cost in the calculation of forecasted net operating income but not separately identified.

Other rate base items, other taxes and administrative and general costs that would be allocable to these functions were not separately identified in the revenue requirement calculation.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 178
Witness: Gary Smith

Data Request:

Please identify the categories of cost by account that are subject to the Gas Cost Adjustment.

Response:

The accounts that are subject to the Gas Cost Adjustment are shown below:

Account	Description
8040	Natural gas city gate purchase
8045	Transportation to City Gate
8060	Exchange gas
8081	Gas withdrawn from storage-Debit
8082	Gas delivered to storage-Credit
1910.14087	Performance Based Rates
1910.14088	Deferred Gas Cost
1910.27314	Pipeline Refunds

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 179
Witness: Gary Smith

Data Request:

Please provide all workpapers and calculations that were used to compute the current gas cost adjustment and weather normalization adjustment.

Response:

Workpapers and calculations for the gas cost adjustment (GCA) are included in conjunction with the quarterly filing with the Kentucky Public Service Commission. Please refer to the Company's response to AG DR1-200 for the filing materials for the current GCA, effective February 1, 2007 (Case No. 2006-00568).

For the weather normalization adjustment, the formula is found on Sheet No. 22 of the Company's tariffs. Each year, the Company updates certain factors for each applicable customer class of residential, commercial and public authority. The factors are the HSF (heat sensitive factor), BL (base load factor) and R (the weighted average distribution charge). The billing system applies these factors in the calculation of the WNA including the normal heating degree days and actual heating degree days for each customer's billing period. The computation of pertinent factors for the winter of 2006-2007 was as follows:

Atmos Energy (Kentucky)

Calculation of Base Load Factor Applicable for Winter 2006-2007

For G-1 Sales - Residential, Commercial and Public Authority Classes

Line No.	Month	No. of Customers	Actual Volumes, ccf	Pro-Forma Adjustments	Pro-Forma Volumes, ccf	Calculated Base Load (BL)
	(a)	(b)	(c)	(d)	(e)	(f)
1	Residential - Class 1 Rate 1					
2						
3	Jul-06	149,549	1,746,901	0	1,746,901	
4	Aug-06	149,337	1,908,628	0	1,908,628	
5	Total	298,886	3,655,529	0	3,655,529	
6						
7	Base Load, ccf per customer per month -					
8	Column e, line 5 divided by column b, line 5, BL(res) =					12.231
9						
10	Commercial - Class 2 Rate 1					
11						
12	Jul-06	17,293	1,357,953	(16,753)	1,341,200	
13	Aug-06	17,081	1,434,589	(12,512)	1,422,077	
14	Total	34,374	2,792,541	(29,265)	2,763,276	
15						
16	Base Load, ccf per customer per month -					
17	Column e, line 14 divided by column b, line 14, BL(com) =					80.389
18						
19	Public Authority - Class 4 Rate 1					
20						
21	Jul-06	1,619	349,002	(51,490)	297,512	
22	Aug-06	1,603	337,901	(39,686)	298,215	
23	Total	3,222	686,903	(91,176)	595,727	
24						
25	Base Load, ccf per customer per month -					
26	Column e, line 23 divided by column b, line 23, BL(PA) =					184.894
27						
28	Note: Pro-forma adjustments reflect commercial customer contract changes from G-1 sales.					

Atmos Energy (Kentucky)
Calculation of Heating Sensitive Factor Applicable for Winter 2006-2007
For G-1 Sales - Residential, Commercial and Public Authority Classes

Line No.	Month	Lagged Actual Degree-Days	Calculated Base Load (BL)	No. of Customers	Total Class Base Load (Col c x Col d)	Actual Volumes, ccf	Class Heating Load (Col f - Col e)	Average HL per Cust. (Col g / Col d)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Residential - Class 1 Rate 1							
1	Sep-05	0.0	12.2310	151,076	1,847,811	1,920,420	72,610	0.48
2	Oct-05	56.0	12.2310	150,362	1,839,078	2,424,214	585,137	3.89
3	Nov-05	307.0	12.2310	153,572	1,878,339	6,258,114	4,379,775	28.52
4	Dec-05	863.0	12.2310	156,105	1,909,320	16,839,318	14,929,998	95.64
5	Jan-06	768.0	12.2310	157,778	1,929,783	19,000,726	17,070,944	108.20
6	Feb-06	760.0	12.2310	158,018	1,932,718	16,057,962	14,125,244	89.39
7	Mar-06	567.0	12.2310	157,942	1,931,789	15,278,847	13,347,058	84.51
8	Apr-06	429.0	12.2310	157,139	1,921,967	8,500,778	6,578,811	41.87
9	May-06	112.0	12.2310	153,253	1,874,437	3,615,455	1,741,018	11.36
10	Jun-06	22.0	12.2310	150,616	1,842,184	2,318,356	476,172	3.16
11	Jul-06	0.0	12.2310	149,549	1,829,134	1,746,901	(82,233)	(0.55)
12	Aug-06	0.0	12.2310	149,337	1,826,541	1,908,628	82,088	0.55
13								
14	Total	3,884.0		153,729	22,563,101	95,869,720	73,306,620	467.01
15								
16		Heating Sensitve Factor, ccf per customer per degree-day -						
17		Column h, line 14 divided by column b line 14, HSF(res) =						0.12024

Atmos Energy (Kentucky)
Calculation of Heating Sensitive Factor Applicable for Winter 2006-2007
For G-1 Sales - Residential, Commercial and Public Authority Classes

Line No.	Month	Lagged Actua Degree-Days	Calculated Base Load (BL)	No. of Customers	Total Class Base Load (Col c x Col d)	Actual Volumes, ccf	Pro-forma Adjustments	Pro-forma Volumes, ccf (Col f + Col g)	Class Heating Load (Col h - Col e)	Average HL per Cust. (Col j / Col d)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Commercial - Class 2 Rate 1									
1	Sep-05	0.0	80.3890	17,202	1,382,852	1,557,045	(14,081)	1,542,964	160,113	9.31
2	Oct-05	56.0	80.3890	17,328	1,392,981	1,947,327	(15,000)	1,932,327	539,347	31.13
3	Nov-05	307.0	80.3890	17,690	1,422,081	2,771,104	(6,281)	2,764,823	1,342,741	75.90
4	Dec-05	863.0	80.3890	18,044	1,450,539	7,115,983	(1,536)	7,114,447	5,663,908	313.89
5	Jan-06	768.0	80.3890	18,078	1,453,272	7,958,651	(11,016)	7,947,635	6,494,363	359.24
6	Feb-06	760.0	80.3890	18,123	1,456,890	6,840,949	(17,183)	6,823,766	5,366,876	296.14
7	Mar-06	567.0	80.3890	18,063	1,452,067	6,230,835	(18,323)	6,212,512	4,760,446	263.55
8	Apr-06	429.0	80.3890	17,944	1,442,500	3,681,970	(17,480)	3,664,490	2,221,989	123.83
9	May-06	112.0	80.3890	17,691	1,422,162	1,929,866	(17,995)	1,911,871	489,709	27.68
10	Jun-06	22.0	80.3890	16,933	1,361,227	1,646,623	(17,236)	1,629,387	268,160	15.84
11	Jul-06	0.0	80.3890	17,293	1,390,167	1,357,953	(16,753)	1,341,200	(48,967)	(2.83)
12	Aug-06	0.0	80.3890	17,081	1,373,125	1,434,589	(12,512)	1,422,077	48,952	2.87
13										
14	Total	3,884.0			16,999,862	44,472,895	(165,396)	44,307,499	27,307,637	1,516.54
15										
16					Heating Sensitve Factor, ccf per customer per degree-day -					
17					Column h, line 14 divided by column b, line 14. HSF(com) =					0.39046
18										
19		Note: Pro-forma adjustments reflect commercial customer contract changes from G-1 sales.								

Atmos Energy (Kentucky)
Calculation of Heating Sensitive Factor Applicable for Winter 2006-2007
For G-1 Sales - Residential, Commercial and Public Authority Classes

Line No.	Month	Lagged Actual Degree-Days	Calculated Base Load (BL)	No. of Customers	Total Class Base Load (Col c x Col d)	Actual Volumes, ccf	Pro-forma Adjustments	Pro-forma Volumes, ccf (Col f + Col g)	Class Heating Load (Col h - Col e)	Average HL per Cust. (Col j / Col d)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(g)	(h)
	Public Authority - Class 4 Rate 1									
1	Sep-05	0.0	184.8940	1,625	300,453	419,529	(52,568)	366,961	66,508	40.93
2	Oct-05	56.0	184.8940	1,618	299,158	479,401	(56,023)	423,378	124,220	76.77
3	Nov-05	307.0	184.8940	1,631	301,562	941,052	(72,392)	868,660	567,097	347.70
4	Dec-05	863.0	184.8940	1,634	302,117	2,018,005	(82,116)	1,935,889	1,633,773	999.86
5	Jan-06	768.0	184.8940	1,645	304,151	2,284,789	(81,877)	2,202,912	1,898,761	1,154.26
6	Feb-06	760.0	184.8940	1,635	302,302	1,894,328	(76,287)	1,818,041	1,515,739	927.06
7	Mar-06	567.0	184.8940	1,631	301,562	1,815,785	(72,959)	1,742,826	1,441,264	883.67
8	Apr-06	429.0	184.8940	1,626	300,638	1,066,825	(60,879)	1,005,946	705,309	433.77
9	May-06	112.0	184.8940	1,620	299,528	588,471	(64,718)	523,753	224,225	138.41
10	Jun-06	22.0	184.8940	1,546	285,846	461,295	(56,049)	405,246	119,400	77.23
11	Jul-06	0.0	184.8940	1,619	299,343	349,002	(51,490)	297,512	(1,831)	(1.13)
12	Aug-06	0.0	184.8940	1,603	296,385	337,901	(39,686)	298,215	1,830	1.14
13										
14	Total	3,884.0			3,593,045	12,656,383	(767,044)	11,889,339	8,296,294	5,079.67
15										
16		Heating Sensitve Factor, ccf per customer per degree-day -								
17		Column h, line 14 divided by column b, line 14, HSF(PA) =								1.30785
18										
19		Note: Pro-forma adjustments reflect public authority customer contract changes from G-1 sales.								

Atmos Energy (Kentucky)
Calculation of Weighted Average Rate (R) Applicable for Winter 2006-2007
For G-1 Sales - Residential, Commercial and Public Authority Classes

Line No.	G-1 Sales by Billing Block	Volumes, ccf (12 months ending 8/31/05)	Pro-Forma Adjustments	Pro-Forma Volumes, ccf	Current Margin per ccf	Current Margin (Col d x Col e)
	(a)	(b)	(c)	(d)	(e)	(f)
1	Residential - Class 1 Rate 1					
2	0-300 Mcf/month	95,401,722	467,999	95,869,720	0.1190	11,408,497
3	Next 14,700 Mcf/month	467,999	(467,999)	0	0.0659	0
4	Over 15,000 Mcf/month	0	0	0	0.0430	0
5	Total	95,869,720	0	95,869,720		11,408,497
6						
7	Weighted Average Rate (R), $/ccf -					
8	Current Rates - Column f, line 6 divided by column d, line 6, R (res) =					0.1190
9						
10						
11	Commercial - Class 2 Rate 1					
12	0-300 Mcf/month	38,866,068	(34,536)	38,831,532	0.1190	4,620,952
13	Next 14,700 Mcf/month	5,606,827	(130,860)	5,475,967	0.0659	360,866
14	Over 15,000 Mcf/month	0		0	0.0430	0
15	Total	44,472,895	(165,396)	44,307,499		4,981,819
16						
17	Weighted Average Rate (R), $/ccf -					
18	Current Rates - Column f, line 15 divided by column d, line 15, R (com) =					0.1124
19						
20						
21	Public Authority - Class 4 Rate 1					
22	0-300 Mcf/month	9,227,311	(105,000)	9,122,311	0.1190	1,085,555
23	Next 14,700 Mcf/month	3,429,072	(662,044)	2,767,028	0.0659	182,347
24	Over 15,000 Mcf/month	0	0	0	0.0430	0
25	Total	12,656,383	(767,044)	11,889,339		1,267,902
26						
27	Weighted Average Rate (R), $/ccf -					
28	Current Rates - Column f, line 25 divided by column d, line 25, R (PA) =					0.1066

Atmos Energy (Kentucky)
Actual & Normal Degree Days
12 Months Ended 08/31/06

Line No.	Month	Actual Ddays	Normal Ddays	Lagged Actual Mo. DDays (16th - 15th)	Lagged Normal 50% Prior Mo. DDays
	(a)	(b)	(c)	(d)	(e)
1					
2	Sep-05	12	28	0	0
3	Oct-05	231	239	56	109
4	Nov-05	483	516	307	376
5	Dec-05	950	859	863	680
6	Jan-06	656	1,006	768	963
7	Feb-06	779	797	760	976
8	Mar-06	536	555	567	653
9	Apr-06	145	247	429	394
10	May-06	92	90	112	154
11	Jun-06	0	0	22	32
12	Jul-06	0	0	0	0
13	Aug-06	0	0	0	0
14					
15		3,884	4,337	3,884	4,337

ATMOS energy

September 28, 2006

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

Re: Case No. 2006-00428

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 29 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

RECEIVED
SEP 29 2006
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

GAS COST ADJUSTMENT	)	CASE NO.
FILING OF	)	2006 - 00428
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.

2

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	Case No. 2006-00000	Difference
		$/Mcf	$/Mcf	$/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 $/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	7.7975	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	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			0.1839	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) Non-Commodity Total	(4) 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

				(1)	(2)	(3)	(4)	(5)
							Non-Commodity	
Line No.	Description		Tariff Sheet No.	Annual Units	Rate	Total	Demand	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) 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				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)					

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		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 Transmi: LP

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

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

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

Tennessee Gas Pipeline

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	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.

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	GL Unit	Jun-06 (1) Month May-06	Jul-06 (2) Month June-06	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	GL Unit	Jun-06 (1) Month May-06	Jul-06 (2) June-06	Aug-06 (3) 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		122,500	122,500	122,500	
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

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	408,375.1		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

Line No.	Amounts Reported:		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			

Line No.			(1) Demand	(2) Commodity	(3) Total
15					
16	**Allocation**				
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

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

Exhibit F

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
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	<u>Zone 1 to Zone 3</u>							
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	<u>SL to Zone 4</u>							
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

				(1)	(2)	(3)	(4)
Line No.	**Description**	**Tariff Sheet No.**		**Purchases**		**Rate**	**Total**
				Mcf	MMbtu	$/MMbtu	$
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

				(1)	(2)	(3)	(4)
Line No.	**Description**	**Tariff Sheet No.**		**Purchases**		**Rate**	**Total**
				Mcf	MMbtu	$/MMbtu	$
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

		(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 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**	

Western Kentucky Gas Company
Gas Supply Plan
Summer 2006
All Volumes MMBTU

REVISED Cut September plan by 1,667/d to get to our target storage level as of Sept 30

ISSUED: 08/23/06

Tennessee Gas	30		31		30		31		31		REVISED 30		31		214
Area	Apr-06		May-06		Jun-06		Jul-06		Aug-06		Sep-06		Oct-06		
Plan Requirements	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	
Danville	49,500	1,650	13,640	440	16,800	560	16,740	540	16,740	540	1,200	40	32,240	1,040	146,860
Harrodsburg	34,500	1,150	21,700	700	16,500	550	16,430	530	16,430	530	2,700	90	28,520	920	136,780
Campbellsville	33,000	1,100	19,840	640	13,500	450	13,640	440	13,640	440	3,300	110	27,900	900	124,820
Lebanon	25,800	860	22,010	710	8,100	270	8,060	260	8,060	260	3,900	130	24,490	790	100,420
GS-2	27,000	900	13,330	430	7,800	260	7,750	250	7,750	250	900	30	20,460	660	84,990
Total Requirements	169,800	5,660	90,520	2,920	62,700	2,090	62,620	2,020	62,620	2,020	12,000	400	133,610	4,310	593,870
Storage Injections	224,615	7,490	224,615	7,250	224,615	7,490	224,615	7,250	112,307	3,620	51,400	1,710	56,154	1,810	1,118,321
		20%		20%		20%		20%		10%		5%		5%	
TOTAL PURCHASES	394,415	13,150	315,135	10,170	287,315	9,580	287,235	9,270	174,927	5,640	63,400	2,110	189,764	6,120	1,712,191

STORAGE INJECTIONS														
	67,384	2,247	67,384	2,175	67,384	2,247	67,384	2,175	33,692	1,086	15,420	513	16,846	543
Danville	38,185	1,273	38,185	1,233	38,185	1,273	38,185	1,233	19,092	615	8,738	291	9,546	308
Harrodsburg	38,185	1,273	38,185	1,233	38,185	1,273	38,185	1,233	19,092	615	8,738	291	9,546	308
Campbellsville	44,923	1,498	44,923	1,450	44,923	1,498	44,923	1,450	22,461	724	10,280	342	11,231	362
Lebanon	35,938	1,198	35,938	1,160	35,938	1,198	35,938	1,160	17,969	579	8,224	274	8,985	290
GS-2	224,615	7,490	224,615	7,250	224,615	7,490	224,615	7,250	112,307	3,620	51,400	1,710	56,154	1,810
Total														

Western Kentucky Gas Company
Gas Supply Plan
Winter 2006-2007
All Volumes MMBTU
10/13/2006 DRAFT

Texas Gas Area	Nov-06 Monthly	30 Daily	Dec-06 Monthly	31 Daily	Jan-07 Monthly	31 Daily	Feb-07 Monthly	28 Daily	Mar-07 Monthly	31 Daily	151 Total Monthly
Zone 2											
Texas Gas Purchase	67,500	2,250	100,700	3,248	223,700	7,216	95,700	3,418	80,700	2,603	568,300
Texas Gas - NNS	177,600	5,920	320,300	10,677	320,300	10,332	302,100	10,789	176,400	5,690	1,296,700
Trunkline	90,000	3,000	124,000	4,000	124,000	4,000	112,000	4,000	77,500	2,500	527,500
Total	335,100	11,170	545,000	17,925	668,000	21,548	509,800	18,207	334,600	10,794	2,392,500
Zone 3											
Texas Gas Purchase	103,800	3,460	331,100	10,681	527,400	17,013	187,200	6,686	167,800	5,413	1,317,300
Texas Gas - NNS	273,300	9,110	492,800	15,897	492,800	15,897	464,800	16,600	271,300	8,752	1,995,000
WKG Owned Storage	898,000	29,933	1,377,000	44,419	1,497,000	48,290	1,317,000	47,036	898,000	28,968	5,987,000
ANR Pipeline	0	0	0	0	0	0	0	0	0	0	0
Midwest	0	0	0	0	0	0	0	0	0	0	0
Total	1,275,100	42,503	2,200,900	70,997	2,517,200	81,200	1,969,000	70,321	1,337,100	43,132	9,299,300
Zone 4											
Texas Gas Purchase	75,700	2,523	114,300	3,687	151,600	4,890	104,100	3,718	89,300	2,881	535,000
Texas Gas - NNS	49,100	1,637	86,900	2,803	86,900	2,803	83,100	2,968	51,400	1,658	357,400
Total	124,800	4,160	201,200	6,490	238,500	7,694	187,200	6,686	140,700	4,539	892,400
Total Texas Gas Purchase	247,000	8,233	546,100	17,616	902,700	29,119	387,000	13,821	337,800	10,897	2,420,600
Total Trunkline	90,000	3,000	124,000	4,000	124,000	4,000	112,000	4,000	77,500	2,500	527,500
Total Texas Gas - NNS	500,000	16,667	900,000	30,000	900,000	30,000	850,000	28,333	499,100	16,637	3,649,100
Total WKG Owned Storage	898,000	29,933	1,377,000	45,900	1,497,000	49,900	1,317,000	43,900	898,000	29,933	5,987,000
Total ANR	0	0	0	0	0	0	0	0	0	0	0
Total Midwest	0	0	0	0	0	0	0	0	0	0	0
Total Purchases	337,000	11,233	670,100	21,616	1,026,700	33,119	499,000	17,821	415,300	13,397	2,948,100
Total Requirements	1,735,000	57,833	2,947,100	95,412	3,423,700	110,442	2,666,000	95,214	1,812,400	58,465	12,584,200

Note 1: Purchases reflect storage activities

Western Kentucky Gas Company
Gas Supply Plan
Summer 2006
All Volumes MMBTU

ISSUED: 3/29/06

Texas Gas Area	Apr-06 (30) Monthly	Apr-06 (30) Daily	May-06 (31) Monthly	May-06 (31) Daily	Jun-06 (30) Monthly	Jun-06 (30) Daily	Jul-06 (31) Monthly	Jul-06 (31) Daily	Aug-06 (31) Monthly	Aug-06 (31) Daily	Sep-06 (30) Monthly	Sep-06 (30) Daily	Oct-06 (31) Monthly	Oct-06 (31) Daily	214 Total Monthly
Planned Req.															
Zone 2															
Texas Gas Req	168,900	5,630	62,100	2,003	20,000	667	16,500	532	14,600	471	57,100	1,903	156,000	5,032	495,200
Trunkline Req	30,000	1,000	31,000	1,000	30,000	1,000	31,000	1,000	31,000	1,000	30,000	1,000	31,000	1,000	214,000
Total Req	198,900	6,630	93,100	3,003	50,000	1,667	47,500	1,532	45,600	1,471	87,100	2,903	187,000	6,032	678,200
Zone 3															
Texas Gas Req	799,300	26,643	395,100	12,745	115,500	3,850	102,400	3,303	193,900	6,255	342,600	11,420	724,400	23,368	2,673,200
ANR Req	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Midwest Req	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Req	799,300	26,643	395,100	12,745	115,500	3,850	102,400	3,303	193,900	6,255	342,600	11,420	724,400	23,368	2,673,200
Zone 4															
Texas Gas Req	72,700	2,423	40,200	1,297	17,700	590	16,600	535	19,800	639	29,700	990	60,400	1,948	257,100
TOTAL REQ	1,070,900	35,697	528,400	17,045	183,200	6,107	166,500	5,371	259,300	8,365	459,400	15,313	971,800	31,348	3,608,500
NN Storage Injections	1,008,419	33,614	1,008,419	32,530	1,008,419	33,614	1,008,419	32,530	504,209	16,265	252,105	8,403	252,105	8,132	5,042,093
WKG Storage Injections	778,581	25,953	778,581	25,116	778,581	25,953	778,581	25,116	389,290	12,558	194,645	6,488	194,645	6,279	3,892,904
Total Storage Injections	1,786,999	59,567	1,786,999	57,645	1,786,999	59,567	1,786,999	57,645	893,500	28,823	446,750	14,892	446,750	14,411	8,934,997
Total Texas Gas Purchases	2,827,899	94,263	2,284,399	73,690	1,940,199	64,673	1,922,499	62,016	1,121,800	36,187	876,150	29,205	1,387,550	44,760	12,360,497
Total Trunkline Purchases	30,000	1,000	31,000	1,000	30,000	1,000	31,000	1,000	31,000	1,000	30,000	1,000	31,000	1,000	214,000
Total ANR Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Midwest Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Purchases	2,857,899	95,263	2,315,399	74,690	1,970,199	65,673	1,953,499	63,016	1,152,800	37,187	906,150	30,205	1,418,550	45,760	12,543,497
STORAGE ALLOCATIONS FOR INVOICING															
NNS Zone 2	358,354	11,945	358,354	11,560	358,354	11,945	358,354	11,560	179,177	5,780	89,588	2,986	89,588	2,890	1,791,770
NNS Zone 3	551,314	18,377	551,314	17,784	551,314	18,377	551,314	17,784	275,657	8,892	137,828	4,594	137,828	4,446	2,756,569
NNS Zone 4	98,751	3,292	98,751	3,186	98,751	3,292	98,751	3,186	49,375	1,593	24,688	823	24,688	796	493,754
NNS Total	1,008,419	33,614	1,008,419	32,530	1,008,419	33,614	1,008,419	32,530	504,209	16,265	252,104	8,403	252,104	8,132	5,042,093
WKG Storage - Zone 3	778,581	25,953	778,581	25,116	778,581	25,953	778,581	25,116	389,290	12,558	194,645	6,488	194,645	6,279	3,892,904

Note 1: Purchases include planned storage injection quantities

Western Kentucky Gas Company
Gas Supply Plan
Winter 2006-2007
All Volumes MMBTU
10/13/2006 DRAFT

Tennessee Gas	30		31		31		28		31		151
Area	Nov-06		Dec-06		Jan-07		Feb-07		Mar-07		
	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	Monthly	Daily	
Harrodsburg	18,000	600	46,500	1,500	55,800	1,800	47,600	1,700	18,600	600	186,500
Danville	33,000	1,100	86,800	2,800	102,300	3,300	86,800	3,100	34,100	1,100	343,000
Lebanon	18,000	600	46,500	1,500	55,800	1,800	44,800	1,600	18,600	600	183,700
Campbellsville	21,000	700	55,800	1,800	68,200	2,200	56,000	2,000	21,700	700	222,700
GS-2	18,000	600	43,400	1,400	49,600	1,600	42,000	1,500	15,500	500	168,500
Total Purchases	108,000	3,600	279,000	9,000	331,700	10,700	277,200	9,900	108,500	3,500	1,104,400
Storage Activity	150,000	5,000	290,000	9,355	370,000	11,935	290,000	10,357	150,000	4,839	1,250,000
Total Requirements	**258,000**	**8,600**	**569,000**	**18,355**	**701,700**	**22,635**	**567,200**	**20,257**	**258,500**	**8,339**	**2,354,400**

Note : Purchases reflect storage activities

MSQ Large	1,163,538										
MSQ Small	150,000										
Storage Withdrawals											
GS Large	135,000	4,500	254,167	8,199	334,167	10,780	254,166	9,077	130,000	4,194	1,107,500
GS Small	15,000	500	35,833	1,156	35,833	1,156	35,834	1,280	20,000	645	142,500
TOTAL	150,000		290,000		370,000		290,000		150,000		1,250,000

1,313,538
1,247,861

Atmos Energy Corporation
Kentucky Division
Gas Supply Plan

Issued	(All)

				Month				
GCA Filing	Supplier	Zone	Data	May-06	May-07	Jun-07	Jul-07	Grand Total
5/1/2007	Texas Gas	2	Sum of Purchases		420,454	378,354	374,854	1,173,662
			Sum of Texas Gas (NNS)		(358,354)	(358,354)	(358,354)	(1,075,062)
			Sum of WKG					
			Sum of Requirements		62,100	20,000	16,500	98,600
		3	Sum of Purchases		1,724,995	1,445,395	1,432,295	4,602,685
			Sum of Texas Gas (NNS)		(551,314)	(551,314)	(551,314)	(1,653,942)
			Sum of WKG		(778,581)	(778,581)	(778,581)	(2,335,743)
			Sum of Requirements		395,100	115,500	102,400	613,000
		4	Sum of Purchases		138,951	116,451	115,351	370,753
			Sum of Texas Gas (NNS)		(98,751)	(98,751)	(98,751)	(296,253)
			Sum of WKG					
			Sum of Requirements		40,200	17,700	16,600	74,500
	Texas Gas Sum of Purchases				2,284,400	1,940,200	1,922,500	6,147,100
	Texas Gas Sum of Texas Gas (NNS)				(1,008,419)	(1,008,419)	(1,008,419)	(3,025,257)
	Texas Gas Sum of WKG				(778,581)	(778,581)	(778,581)	(2,335,743)
	Texas Gas Sum of Requirements				497,400	153,200	135,500	786,100
5/1/2007 Sum of Purchases					2,284,400	1,940,200	1,922,500	6,147,100
5/1/2007 Sum of Texas Gas (NNS)					(1,008,419)	(1,008,419)	(1,008,419)	(3,025,257)
5/1/2007 Sum of WKG					(778,581)	(778,581)	(778,581)	(2,335,743)
5/1/2007 Sum of Requirements					497,400	153,200	135,500	786,100

Atmos Energy Corporation
Kentucky Division
Gas Supply Plan

Issu	(All)

GCA Filing	Supplier	Zone	Data	May-07	Jun-07	Jul-07	Grand Total
5/1/2007	Trunkline	2	Sum of Purchases	31,000	30,000	31,000	92,000
			Sum of Requirements	31,000	30,000	31,000	92,000
	Trunkline Sum of Purchases			31,000	30,000	31,000	92,000
	Trunkline Sum of Requirements			31,000	30,000	31,000	92,000
5/1/2007 Sum of Purchases				31,000	30,000	31,000	92,000
5/1/2007 Sum of Requirements				31,000	30,000	31,000	92,000

Atmos Energy Corporation
Kentucky Division
Supply Plan

Issued	(All)

GCA Filing	Supplier	Zone	Data	May-07	Jun-07	Jul-07	Grand Total
5/1/2007	Tennessee Gas	Danville	Sum of Purchases	81,024	84,184	84,124	249,332
			Sum of Storage	(67,384)	(67,384)	(67,384)	(202,152)
			Sum of Requirements	13,640	16,800	16,740	47,180
		Harrodsburg	Sum of Purchases	59,885	54,685	54,615	169,185
			Sum of Storage	(38,185)	(38,185)	(38,185)	(114,555)
			Sum of Requirements	21,700	16,500	16,430	54,630
		Campbellsville	Sum of Purchases	58,025	51,685	51,825	161,535
			Sum of Storage	(38,185)	(38,185)	(38,185)	(114,555)
			Sum of Requirements	19,840	13,500	13,640	46,980
		Lebanon	Sum of Purchases	66,933	53,023	52,983	172,939
			Sum of Storage	(44,923)	(44,923)	(44,923)	(134,769)
			Sum of Requirements	22,010	8,100	8,060	38,170
		GS-2	Sum of Purchases	49,268	43,738	43,688	136,694
			Sum of Storage	(35,938)	(35,938)	(35,938)	(107,814)
			Sum of Requirements	13,330	7,800	7,750	28,880
	Tennessee Gas Sum of Purchases			315,135	287,315	287,235	889,685
	Tennessee Gas Sum of Storage			(224,615)	(224,615)	(224,615)	(673,845)
	Tennessee Gas Sum of Requirements			90,520	62,700	62,620	215,840
5/1/2007 Sum of Purchases				315,135	287,315	287,235	889,685
5/1/2007 Sum of Storage				(224,615)	(224,615)	(224,615)	(673,845)
5/1/2007 Sum of Requirements				90,520	62,700	62,620	215,840

Atmos Energy Corporation
Correction Factor (CF)
r the Three Months Ended October 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	August-06	957,239	5,524,981.22	3,665,059.17	1,859,922.05	0.00	1,859,922.05
2							
3	September-06	635,846	4,298,501.44	3,719,994.94	578,506.50	0.00	578,506.50
4							
5	October-06	1,151,786	11,115,568.91	6,369,828.61	4,745,740.30	0.00	4,745,740.30
6							
7							
8							
9							
10							
11							
12							
13	Total Gas Cost						
14	Under/(Over) Recovery		20,939,051.57	13,754,882.72	7,184,168.85	0.00	7,184,168.85
15							
16	PBR Saving reflected in Gas Cost		593,186.41				
17							
18	Account 191 Balance @ July, 2006						($5,862,937.55)
19							
20	Total Gas Cost Under/(Over) Recovery for the three months ended October, 2006						7,184,168.85
21	Recovery from outstanding Correction Factor (CF)						(275,434.63)
22	Account 191 Balance @ October, 2006						1,045,796.67
23							
24							
25							
26							
27							
28	Derivation of Correction Factor (CF):						
29							
30	Account 191 Balance					$1,045,797	
31	Divided By: Total Expected Customer Sales					18,983,274	MCF
32							
33	**Correction Factor (CF)**					**$0.0551**	**/MCF**
34							
35							

Atmos Energy Corporation
Recoverable Gas Cost Calculation
r the Three Months Ended October 1, 2006
ase No. 2006-000

Line No.	Description	Unit	GL Sep-06 (1) Month August-06	Oct-06 (2) Month September-06	Nov-06 (3) Month October-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	1,316,214	971,503	1,611,360	pages 5
9	Off System Storage					
10	Texas Gas Transmission	Mcf	0	0	0	
11	Tennessee Gas Pipeline	Mcf	(106,118)	9,522	(6,534)	
12	System Storage					
13	Withdrawals	Mcf	4	0	(86,870)	
14	Injections	Mcf	(248,239)	(948,335)	(509,329)	
15	Producers	Mcf	13,872	12,529	12,091	
16	Pipeline Imbalances cashed out	Mcf	0	0	0	
17	System Imbalances [2]	Mcf	(18,494)	590,627	131,068	
18	**Total Supply**	Mcf	957,239	635,846	1,151,786	
19						
20	Change in Unbilled	Mcf				
21	Company Use	Mcf	0	0	0	
22	Unaccounted For	Mcf	0	0	0	
23	**Total Sales**	Mcf	957,239	635,846	1,151,786	

[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
r the Three Months Ended October 1, 2006
Case No. 2006-000

Line No.	Description	GL Unit	Sep-06 (1) August-06	Oct-06 (2) Month September-06	Nov-06 (3) October-06	Source Document
1	**Supply Cost**					
2	Pipelines:					
3	Texas Gas Transmission [1]	$	1,181,945	1,179,985	1,614,294	
4	Tennessee Gas Pipeline [1]	$	180,651	186,971	263,695	
5	Trunkline Gas Company [1]	$	7,899	7,644	7,893	
6	Midwestern Pipeline [1]	$	0	0	0	
7	**Total Pipeline Supply**	$	1,370,494	1,374,600	1,885,882	
8	Total Other Suppliers	$	9,544,943	5,404,068	7,547,579	page 5
9	Hedging Settlements		0	0	0	
10	Off System Storage					
11	Texas Gas Transmission	$	0	0	0	
12	Tennessee Gas Pipeline	$	(772,031)	74,391	45,067	
13	WKG Storage		122,500	122,500	122,500	
14	System Storage					
15	Withdrawals	$	29	0	601,710	
16	Injections	$	(2,235,803)	(5,200,776)	(2,517,545)	
17	Producers	$	97,946	73,235	57,950	
18	Pipeline Imbalances cashed out	$	0	0	0	
19	System Imbalances [2]	$	(2,603,098)	2,450,484	3,372,427	
20	**Sub-Total**	$	5,524,981	4,298,501	11,115,569	
21						
22	Change in Unbilled	$				
23	Company Use	$	0	0	0	
24	Recovered thru Transportation	$	0	0	0	
25	**Total Recoverable Gas Cost**	$	5,524,981	4,298,501	11,115,569	

[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)
r the Three Months Ended October, 2006
ase No. 2006-000

Line No.	Month	Type of Sales	Mcf Sold	Rate	Amount
1	August-06	G-1 Sales	393,246.7	($0.1749)	($68,778.84)
2		G-1 HLF	0.0	(0.1749)	0.00
3		G-2 Sales	20,155.7	(0.1749)	(3,525.23)
4		T-3 Overrun Sales	2,010.0	(0.1924)	(386.72)
5		T-4 Overrun Sales	2,688.0	(0.1924)	(517.17)
6		LVS-1 Sales	0.0	0.0000	0.00
7		LVS-2 Sales	(1,020.0)	0.0000	0.00
8		LVS HLF Sales	0.0	0.0000	0.00
9		Total	417,080.3		(73,207.96)
10					
11	September-06	G-1 Sales	383,534.8	($0.1749)	($67,080.23)
12		G-1 HLF	0.0	(0.1749)	0.00
13		G-2 Sales	31,369.8	(0.1749)	(5,486.58)
14		T-3 Overrun Sales	2,522.0	(0.1924)	(485.23)
15		T-4 Overrun Sales	527.0	(0.1924)	(101.39)
16		LVS-1 Sales	0.0	0.0000	0.00
17		LVS-2 Sales	688.0	0.0000	0.00
18		LVS HLF Sales	0.0	0.0000	0.00
19		Total	418,641.6		(73,153.43)
20					
21	October-06	G-1 Sales	716,963.8	($0.1749)	($125,396.96)
22		G-1 HLF	0.0	(0.1749)	0.00
23		G-2 Sales	18,714.8	(0.1749)	(3,273.21)
24		T-3 Overrun Sales	756.0	(0.1924)	(145.45)
25		T-4 Overrun Sales	1,339.0	(0.1924)	(257.62)
26		LVS-1 Sales	0.0	0.0000	0.00
27		LVS-2 Sales	24,624.0	0.0000	0.00
28		LVS HLF Sales	0.0	0.0000	0.00
29		Total	762,397.6		(129,073.24)
50	Total Recovery from Correction Factor (CF)				($275,434.63)

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

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
ditional and Other Pipelines

Exhibit D
Page 5 of 5

		GL	Sep-06		Oct-06		Nov-06	
			August-06		September-06		October-06	
	Description		MCF	Cost	MCF	Cost	MCF	Cost
1	**Texas Gas Pipeline Area**							
2	LG&E Natural		0	0.00	0	0.00	0	0.00
3	Woodward Marketing		0	0.00	0	0.00	0	0.00
4	Texaco Gas Marketing		0	0.00	0	0.00	0	0.00
5	CMS		0	0.00	0	0.00	0	0.00
6	WESCO		0	0.00	0	0.00	0	0.00
7	Southern Energy Company		0	0.00	0	0.00	0	0.00
8	Union Pacific Fuels		0	0.00	0	0.00	0	0.00
9	Atmos Energy Marketing, LLC		1,110,094	8,035,183.48	877,389	4,888,263.05	1,388,062	6,500,074.70
10	Engage		0	0.00	0	0.00	0	0.00
11	ERI		0	0.00	0	0.00	0	0.00
12	Prepaid		0	0.00	0	0.00	0	0.00
13	Reservation		0	0.00	0	0.00	0	0.00
14	Hedging Costs - All Zones		0	0.00	0	0.00	0	0.00
15								
16	**Total**		1,110,094	$8,035,183.48	877,389	$4,888,263.05	1,388,062	$6,500,074.70
17								
18								
19	**Tennessee Gas Pipeline Area**							
20	Atmos Energy Marketing, LLC		175,939	1,287,773.57	64,629	352,980.87	192,728	912,009.38
21	Union Pacific Fuels		0	0.00	0	0.00	0	0.00
22	WESCO		0	0.00	0	0.00	0	0.00
23	Prepaid		0	0.00	0	0.00	0	0.00
24	Reservation		0	0.00	0	0.00	0	0.00
25	Fuel Adjustment		0	0.00	0	0.00	0	0.00
26								
27	**Total**		175,939	$1,287,773.57	64,629	$352,980.87	192,728	$912,009.38
28								
29								
30	**Trunkline Gas Company**							
31	Atmos Energy Marketing, LLC		30,181	221,985.92	29,485	162,824.46	30,570	135,494.92
32	Engage		0	0.00	0	0.00	0	0.00
33	Prepaid		0	0.00	0	0.00	0	0.00
34	Reservation		0	0.00	0	0.00	0	0.00
35	Fuel Adjustment		0	0.00	0	0.00	0	0.00
36								
37	**Total**		30,181	$221,985.92	29,485	$162,824.46	30,570	$135,494.92
38								
39								
40	**Midwestern Pipeline**							
41	Atmos Energy Marketing, LLC		0	0.00	0	0.00	0	0.00
42	LG&E Natural		0	0.00	0	0.00	0	0.00
43	Anadarko		0	0.00	0	0.00	0	0.00
44	Prepaid		0	0.00	0	0.00	0	0.00
45	Reservation		0	0.00	0	0.00	0	0.00
46	Fuel Adjustment		0	0.00	0	0.00	0	0.00
47								
48	**Total**		0	$0.00	0	$0.00	0	$0.00
49								
50								
51	**All Zones**							
52	Total		1,316,214	$9,544,942.97	971,503	$5,404,068.38	1,611,360	$7,547,579.00
53								
54								
55								

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

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

		August, 2006		September, 2006		October, 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**	1,110,094	$8,035,183.48	877,389	$4,888,263.05	1,388,062	$6,500,074.70
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**	175,939	$1,287,773.57	64,629	$352,980.87	192,728	$912,009.38
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	$221,985.92	29,485	$162,824.46	30,570	$135,494.92
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	0	$0.00
49							
50							
51	**All Zones**						
52	Total	1,316,214	$9,544,942.97	971,503	$5,404,068.38	1,611,360	$7,547,579.00
53							
54							
55							

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

Company	(All)
Account	1910
Ser[illegible]e	(All)
Su[illegible]count	14088

Sum of Journal Amount	Group	
Month	Recoveries	Grand Total
Aug-06	(3,738,267.13)	(3,738,267.13)
Sep-06	(3,810,030.50)	(3,810,030.50)
Oct-06	(6,498,901.85)	(6,498,901.85)
Grand Total	(14,047,199.48)	(14,047,199.48)

os Energy Corporati
States - Kentucky Divis..n - (Rate Div 9)
erred Gas Costs Reconciliation
ounts 1910 14088
e Administration vs General Ledger
onths Ended October (Production)

duction Month	**May-06**	**Jun-06**	**Jul-06**	**Aug-06**	**Sep-06**	**Oct-06**	**Nov-06**	**Dec-06**
e Administration:								
ginning Balance - Rate Administration	(3,320,396.77)	(6,414,387.35)	(6,048,570.80)	(5,862,937.55)	(4,059,341.33)	(3,570,870.35)	1,045,796.67	1,908,476.27
dd: Current Production Gas Cost	3,315,840.91	5,256,810.98	4,202,910.27	5,524,981.22	4,298,501.44	11,115,568.87	14,477,402.42	23,096,688.22
Deduct: Current Recoveries	(6,409,831.49)	(4,890,994.54)	(4,017,277.02)	(3,738,267.13)	(3,826,912.63)	(6,498,901.85)	(13,614,722.82)	(20,910,203.75)
Deduct: Recoveries related to PBR, Refund					16,882.13			
ding Balance - Rate Administration	(6,414,387.35)	(6,048,570.91)	(5,862,937.55)	(4,076,223.46)	(3,570,870.39)	1,045,796.67	1,908,476.27	4,094,960.74
justments (Rate Administration):								
djusted Ending Balance - Rate Administration	(6,414,387.35)	(6,048,570.91)	(5,862,937.55)	(4,076,223.46)	(3,570,870.39)	1,045,796.67	1,908,476.27	4,094,960.74
econciliation to the General Ledger:	**Jun-06**	**Jul-06**	**Aug-06**	**Sep-06**	**Oct-06**	**Nov-06**	**Dec-06**	**Jan-07**
ming Differences:								
Invoice Accrual not booked				16,882.13				
djustments (Gas Cost Accounting):								
Rounding		0.11			0.04			
Booked incorrectly. DR 1910.14088 CR 1910.14087								(19,723.59)
djustments (Revenue Accounting):								
nding Balance - General Ledger	(6,414,387.35)	(6,048,570.80)	(5,862,937.55)	(4,059,341.33)	(3,570,870.35)	1,045,796.67	1,908,476.27	4,075,237.15
ifference in Unadjusted Ending Balances	0.00	(0.11)	0.00	(16,882.13)	(0.04)	0.00	0.00	19,723.59
ifference in Adjusted Ending Balances	0.00	(0.11)	0.00	(16,882.13)	(0.04)	0.00	0.00	19,723.59
910.14088.009XXX	(6,414,387.35)	(6,048,570.80)	(5,862,937.55)	(4,059,341.33)	(3,570,870.35)	1,045,796.67	1,908,476.27	4,075,237.15
eneral Ledger less Reconciliation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Prepared by: _____ Date: _____

Reviewed by: _____ Date: _____

Company	(All)
Service	9000

V:\Rate Administration\Kentucky\General Ledger\[General Ledger (8000-8130) stat.xls]Activity (Groups)

Sum of Journal Amount		Month			
Report Group	Report Sub Group	Sep-06	Oct-06	Nov-06	Grand Total
Off System Storage	Tennessee Gas Pipeline	(106,118.00)	9,522.00	(6,534.00)	(103,130.00)
Off System Storage Total		(106,118.00)	9,522.00	(6,534.00)	(103,130.00)
Other Suppliers	Tennessee Gas Pipeline	175,939.00	64,629.00	192,728.00	433,296.00
	Texas Gas Transmission	1,110,094.00	877,389.00	1,388,062.00	3,375,545.00
	Trunkline Gas Company	30,181.00	29,485.00	30,570.00	90,236.00
Other Suppliers Total		1,316,214.00	971,503.00	1,611,360.00	3,899,077.00
Producers	(blank)	13,872.00	12,529.00	12,091.00	38,492.00
Producers Total		13,872.00	12,529.00	12,091.00	38,492.00
System Imbalances	(blank)	(18,494.00)	590,627.00	131,068.00	703,201.00
System Imbalances Total		(18,494.00)	590,627.00	131,068.00	703,201.00
System Storage	Injections	(248,239.00)	(948,335.00)	(509,329.00)	(1,705,903.00)
	Withdrawals	4.00		(86,870.00)	(86,866.00)
System Storage Total		(248,235.00)	(948,335.00)	(596,199.00)	(1,792,769.00)
Unbilled	(blank)	(6,854.00)	394,064.00	294,621.00	681,831.00
Unbilled Total		(6,854.00)	394,064.00	294,621.00	681,831.00
Recoveries	(blank)	441,940.70	775,627.61	1,551,675.48	2,769,243.79
Recoveries Total		441,940.70	775,627.61	1,551,675.48	2,769,243.79
Sweep	(blank)	(957,239.00)	(635,846.00)	(1,151,786.00)	(2,744,871.00)
Sweep Total		(957,239.00)	(635,846.00)	(1,151,786.00)	(2,744,871.00)
Grand Total		435,086.70	1,169,691.61	1,846,296.48	3,451,074.79

mpany	(All)
rvice	(All)
count	(All)

m of Journal Amount		Month			
port Group	Report Sub Group	Sep-06	Oct-06	Nov-06	Grand Total
mpany Use	(blank)	(781.32)	(462.45)	7,803.72	6,559.95
mpany Use Total		(781.32)	(462.45)	7,803.72	6,559.95
f System Storage	Tennessee Gas Pipeline	(772,030.67)	74,390.62	45,066.99	(652,573.06)
f System Storage Total		(772,030.67)	74,390.62	45,066.99	(652,573.06)
her Suppliers	Tennessee Gas Pipeline	1,287,773.57	352,980.87	912,009.38	2,552,763.82
	Texas Gas Transmission	8,035,183.48	4,888,263.05	6,500,074.70	19,423,521.23
	Trunkline Gas Company	221,985.92	162,824.46	135,494.92	520,305.30
ther Suppliers Total		9,544,942.97	5,404,068.38	7,547,579.00	22,496,590.35
ipelines	Tennessee Gas Pipeline	180,650.95	186,971.20	263,695.31	631,317.46
	Texas Gas Transmission	1,181,944.57	1,179,984.61	1,614,293.66	3,976,222.84
	Trunkline Gas Company	7,898.80	7,644.00	7,892.60	23,435.40
ipelines Total		1,370,494.32	1,374,599.81	1,885,881.57	4,630,975.70
roducers	(blank)	97,946.11	73,234.86	57,950.21	229,131.18
roducers Total		97,946.11	73,234.86	57,950.21	229,131.18
ystem Imbalances	(blank)	(2,603,098.07)	2,450,483.51	3,372,426.75	3,219,812.19
ystem Imbalances Total		(2,603,098.07)	2,450,483.51	3,372,426.75	3,219,812.19
ystem Storage	Injections	(2,235,802.91)	(5,200,775.74)	(2,517,545.12)	(9,954,123.77)
	Withdrawals	29.47		601,709.51	601,738.98
	Other (East Diamond)	122,500.00	122,500.00	122,500.00	367,500.00
ystem Storage Total		(2,113,273.44)	(5,078,275.74)	(1,793,335.61)	(8,984,884.79)
Grand Total		5,524,199.90	4,298,038.99	11,123,372.63	20,945,611.52

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. 2006-00 374

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. 2006-00374 **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

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.**
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 28 2006

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

GAS COST ADJUSTMENT	)	Case No. 2006 - 00374
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.

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 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.		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. 2006-00135 $/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. 2006-00135	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	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		0.1839	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) 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	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.	Description	Annualized MDQs in MMbtu	Allocation	Commodity Charge $/MMbtu	Weighted Average
28	Used to allocate transportation non-commodity				
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 P... ..ne

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)	(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.

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*		*Maximum* Rate Per Dt	*Minimum* Rate Per Dt	Fuel Reimbursement
		Sec. 24	Sec. 25			
	(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												
WACOGs												

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

PUBLIC DISCLOSURE

Atmos Energy Corporation
Correction Factor (CF)
For the Three Months Ended April 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	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) February-06	Apr-06 (2) Month 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.

ıtmos 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) 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

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

		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

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

Exhibit F

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 Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 180
Witness: Gary Smith

Data Request:

Please identify and provide copies of the Company's application(s) for the current gas cost adjustment and weather normalization adjustment.

Response:

Enclosed as Attachment AG DR 1-180 WNA Sheets 1-7 is a copy of the Company's Application for the current Weather Normalization Adjustment (Case No. 2005-00268).

The Application for the current gas cost adjustment (GCA), effective February 1, 2007 (Case No. 2006-00568), is attached. Please also refer to the Company's response to AG DR1-200.

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.
Mark R. Hutchinson
T. Steven Poteat

bill@whplawfirm.com
randy@whplawfirm.com
steve@whplawfirm.com

June 22, 2005

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

RE: Application of Atmos Energy Corporation for an Order Continuing the Weather Normalization Adjustment

Case No. 2005-00268

Dear Ms. O'Donnell:

I enclose herewith an original, plus eleven (11) copies, of an Application of Atmos Energy Corporation for an Order Continuing the Weather Normalization Adjustment. Thanks.

Very truly yours,

Mark R. Hutchinson

MRH:bkk

Enclosures

JUN 29 2005

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

THE APPLICATION OF ATMOS ENERGY CORPORATION, FOR AN ORDER CONTINUING THE WEATHER NORMALIZATION ADJUSTMENT FOR FIVE (5) ADDITIONAL YEARS

Case No 2005-00268

APPLICATION

Comes now Atmos Energy Corporation ("Company" or "Atmos Energy") and files its Application herein for an Order continuing the Weather Normalization Adjustment ("WNA") for five (5) additional years. In support of this Application, Atmos Energy states as follows:

(1) In the Company's last general rate adjustment case (In the Matter of: The Application of Western Kentucky Gas Company For An Adjustment of Rates, Case No. 99-070), the Commission, by Order dated December 21, 1999 (the "Order"), approved implementation by the Company of the WNA for a five (5) year trial period. Atmos Energy was ordered to file annual reports on the WNA with the Commission in the format set forth in Appendix C of the Order for each year by no later than June 30th of the following summer. The WNA was implemented by the Company on November 1, 2000. Commencing with June 30, 2001, and continuing each June thereafter, the Company filed the required annual reports. The fifth and final report is being filed simultaneously with this Application.

(2) The Commission's December 21, 1999 Order further directed that should the Company "...wish to continue the WNA pilot beyond the five year period or implement the WNA on a permanent basis...", it should make such a request in the form of a formal application to be submitted to the Commission when it makes its final annual WNA filing in June, 2005. For

the reasons set forth below, Atmos Energy requests authority to continue the WNA for an additional five (5) year period.

(3) The WNA mechanism was initially proposed to separate, or "decouple", impacts of weather-related volume on the Company's margin recovery. During periods of colder than normal weather, the WNA lowers the Company's distribution charge and softens the impact of colder weather on consumers. Conversely, warmer than normal weather increases the distribution charge. Accordingly the WNA, for weather-related volumes, stabilizes the Company's revenues and stabilizes the consumers billings.

(4) Traditional ratemaking defines the utility's *revenue requirement*, then separates the Company's non-gas related revenues into fixed monthly charges and commodity-driven charges. The commodity driven distribution charges are based upon volumes expected with normal winter weather. However, to the extent actual winter temperatures deviate from normal, volumes will vary and the Company may exceed or fall short of its established revenue requirements. A WNA mechanism is intended to compensate for this weather variance. The WNA mechanism has performed very well during the pilot period and has met this intended purpose.

(5) Atmos Energy, in further pursuit of stabilizing customer's billings, has also secured approval of hedging programs in each of the past four years designed to stabilize gas supply prices for consumers and avoid price spikes of today's market. The WNA mechanism complements those efforts as it relates to stabilizing the non-gas portion of a customer's bill.

(6) Atmos Energy was the third gas utility of the five major local distribution companies (LDCs) in Kentucky to adopt a WNA mechanism. Today, four of the five large LDCs utilize a WNA mechanism (Atmos Energy, Columbia Gas, Louisville Gas & Electric and Delta)

(7) WNA mechanisms and a broader array of rate structures which further decouple a gas utility's earnings from volumetric measures have been endorsed recently by the National Association of Regulatory Commissioners ("NARUC"). In July of 2004, NARUC, in conjunction with the National Resources Defense Council and AGA, issued a resolution which encourages regulators to approve such decoupling mechanisms for the utilities they regulate. The resolution states, *in relevant part, the following:*

> "WHEREAS, the Natural Resources Defense Council (NRDC), the American Gas Association (AGA) and the American Council for an Energy Efficient Economy (ACEEE) have urged public utility commissions to align the interests of consumers, utility shareholders, and society as a whole by encouraging conservation. Among the mechanisms supported by these groups are the use of automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales."

Atmos Energy supports the intent of the above resolution.

(8) The Company proposes to utilize the same basis for normal Heating Degree Days (NOAA Normals for 1960-1989) which were the basis for weather normalization of the test period upon which rates were based in Case No. 99-070. The Company also proposes to continue to annually update the Base Load ("BL"), Heating Sensitive Factors ("HSF"), and average distribution rate factor ("R") for each of the affected classes of firm sales ("Rate G-1") service, residential, commercial and public authority

(9) Given the favorable performance of the WNA mechanism during the five year pilot, no changes in the existing tariff or processes are proposed. The proposed five year extension

of the WNA mechanism would begin November 1, 2006. Annual reports, in the format suggested by the Commission, would continue as currently prescribed.

(10) Company's principal operating office and place of business is 2401 New Hartford Road, Owensboro, Kentucky 42303. The post office address of Applicant is P.O. Box 650205, Dallas, Texas 75265-0205.

(11) A certified copy of Applicant's Restated Articles of Incorporation as Amended, together with all amendments thereto, is on file in the records of the Commission and is incorporated herein by reference. See, *In the Matter of the Application of Atmos Energy Corporation, Through Its Division Western Kentucky Gas Company of Owensboro, Kentucky, for an Order Authorizing the Issuance of up to 1,655,740 Shares of Common Stock, Case No. 2000-436*. There have been no changes to the Articles of Incorporation since they were filed with the Commission in Docket No. 2000-436.

(12) Correspondence and communications with respect to this Application should be directed to:

Gary Smith
Vice President, Marketing and Regulatory Affairs
Atmos Energy, Kentucky Operations
2401 New Hartford Road
Owensboro, Kentucky 42303

Douglas C. Walther
Senior Attorney
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205

Mark R. Hutchinson
Attorney at Law
611 Frederica Street
Owensboro, Kentucky 42301

WHEREFORE, Atmos Energy respectfully requests that the Commission authorize by appropriate order, a continuation of Atmos Energy's WNA for five (5) additional years.

Respectfully submitted on this 28 day of June, 2005.

Douglas C. Walther
Senior Attorney
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205

Mark R. Hutchinson
Attorney at Law
611 Frederica Street
Owensboro, Kentucky 42301

COUNSEL FOR ATMOS ENERGY CORPORATION

By: ______________________

W:\WEATHERNORMALIZATION\APPLICATION

Atmos Energy Corporation (KY Division)
WNA Summary Report
2004-2005 Heating Season vs 2003-2004
November - April

		2004-2005 Heating Season							2003-2004 Season
		November	December	January	February	March	April	Total	Total
RESIDENTIAL									
WNA Customers		152,632	156,212	157,010	159,346	159,253	158,060	157,119	157,083
Total Customers		152,632	156,212	157,010	159,346	159,253	158,060	157,119	157,083
WNA Revenue	$	241,130	130,364	379,178	373,653	52,760	30,297	1,207,392	755,922
WNA Volume Adjustment	MCF	202,630	109,550	318,637	314,003	44,336	25,460	1,014,616	661,279
Avg. WNA / Customer	$	1.58	0.83	2.41	2.34	0.33	0.19	7.68	5.01
COMMERCIAL									
WNA Customers		17,413	17,767	17,755	17,984	17,923	17,781	17,771	17,765
Total Customers		17,417	17,771	17,759	17,988	17,927	17,785	17,775	17,786
WNA Revenue	$	77,009	37,661	132,660	123,522	11,416	13,499	395,809	269,321
WNA Volume Adjustment	MCF	68,270	33,405	117,624	109,505	10,122	11,987	350,894	239,610
Avg. WNA / Customer	$	4.42	2.12	7.47	6.87	0.64	0.76	22.27	15.17
PUBLIC AUTHORITY									
WNA Customers		1,655	1,646	1,636	1,654	1,650	1,649	1,648	1,668
Total Customers		1,655	1,646	1,636	1,654	1,650	1,649	1,648	1,668
WNA Revenue	$	26,773	10,539	34,106	33,536	4,835	2,483	112,365	78,735
WNA Volume Adjustment	MCF	25,618	10,163	32,076	32,339	4,665	2,394	108,356	76,668
Avg. WNA / Customer	$	16.18	6.40	20.90	20.28	2.93	1.51	68.17	47.21
TOTAL									
WNA Revenue	$	344,912	178,584	546,054	530,721	69,016	46,279	1,715,566	1,134,081
WNA Volume Adjustment	MCF	296,718	153,116	469,237	455,847	59,124	39,821	1,473,869	977,557
WEATHER									
Billing HDD'S Actual		199	601	836	745	675	409	3,465	3,639
Billing HDD'S Normal		319	655	970	882	693	424	3,946	3,953
Warmer(Colder) then Normal	%	37.6	8.7	13.8	15.5	2.6	3.5	12.2	7.9
Calendar HDD'S Actual		427	893	783	637	630	231	3,607	3,678
Calendar HDD'S Normal		516	859	1,006	797	555	247	3,980	3,980
Warmer(Colder) then Normal	%	17.2	-4.0	22.2	20.1	-14.6	6.5	9.4	7.6
CUSTOMER SERVICE									
Total No. of WNA Inquiries								203	134
No. of Inquiries Not Satisfied								0	0

ATMOS energy

RECEIVED

JAN 11 2007

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

For Entire Service Area
P.S.C. No. 1
Twentieth SHEET No. 4
Cancelling
Nineteenth 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	@	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.

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

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

For Entire Service Area
P.S.C. No. 1
Twentieth SHEET No. 6
Cancelling
Nineteenth SHEET No. 6

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	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	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				
26	Monthly Refund Factor			

Line No.		Case No.	Effective Date	G - 1	G - 1 / HLF	G - 2
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	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. 2006-00428	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	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) 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

				(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							

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				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

				(1)	(2)	(3)	(4)
Line No.	Description	Tariff Sheet No.		Purchases		Rate	Total
				Mcf	MMbtu	$/MMbtu	$
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

		(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 Mcf	(2) MMbtu	(3) Rate $/MMbtu	(4) Total $
1	<u>Texas Gas Area</u>					
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	<u>Tennessee Gas Area</u>					
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	<u>Trunkline Gas Area</u>					
15	Firm Transportation		212,077	219,500	6.6225	1,453,639
16						
17						
18	<u>WKG System Storage</u>					
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	<u>LVS Commodity Credit to System</u>					
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**	

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

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): $0.0016

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

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

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)	(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.

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	Adjustment Sec. 24	Maximum Rate Per Dt	Minimum Rate Per Dt	Fuel Reimbursement
	(1)	(2)	(3)	(4)	(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					

- 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												

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

WACOGs												

RECEIVED

JAN 11 2007

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

REVISED GAS COST ADJUSTMENT	)	CASE NO.
FILING OF	)	2006 - 00568
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 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

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 181
Witness: Gary Smith

Data Request:

Please identify and provide copies of the Commission orders that approved the present procedures used to calculate the gas cost adjustment and the weather normalization adjustment.

Response:

The current Weather Normalization Adjustment rider was approved for a five-year extension in Case No. 2005-00268. A copy of the Order in that Case is attached as Attachment AG DR 1-181 ATT1, WNA Sheets 1 and 2.

The present procedures used to calculate the Gas Cost Adjustment were established in Case No. 99-070. A copy of that Commission Order is attached and labeled AG DR 1-181 ATT2.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF ATMOS ENERGY CORPORATION, FOR AN ORDER CONTINUING THE WEATHER NORMALIZATION ADJUSTMENT FOR FIVE (5) ADDITIONAL YEARS	))))	CASE NO. 2005-00268

ORDER

On June 29, 2005, Atmos Energy Corporation ("Atmos") filed an application requesting to continue its Weather Normalization Adjustment mechanism ("WNA") for 5 additional years, through October 31, 2010. Atmos's WNA was initially approved for a 5-year pilot period commencing on November 1, 2000, as part of the settlement in Case No. 1999-00070.[1] On August 5, 2005, Atmos clarified various items in its application in its response to a Commission Staff data request.

A WNA is designed to mitigate the effects that abnormal heating season weather can have on sales volumes, customer bills, and utility revenues. Atmos's application states that its WNA "has performed very well during the pilot period and has met this intended purpose." Atmos proposes to continue its WNA with no changes to the tariff formulas or the workings of the mechanism.

Based on a review of the application and Atmos's data response and being otherwise sufficiently advised, the Commission finds that Atmos's request to continue its WNA for 5 additional years is reasonable and should be approved.

[1] Case No. 1999-00070, The Application of Western Kentucky Gas Company for an Adjustment of Rates, Order dated December 21, 1999.

IT IS THEREFORE ORDERED that:

1. Atmos's WNA shall be continued for a period of 5 years commencing November 1, 2005.

2. Within 20 days of the date of this Order, Atmos shall file its revised WNA tariff rider showing the date issued and that it was issued by authority of this Order.

Done at Frankfort, Kentucky, this 19th day of September, 2005.

By the Commission

ATTEST:

Executive Director

title:	199900070_12211999.doc
rw_attachment_flag:	N
path_num:	1
file_name:	199900070_12211999.doc
word_link:	msword97
rw_filter:	HT
top_lines:	COMMONWEALTH OF KENTUCKY BEFORE THE PUBLIC SERVICE COMMISSION In the Matter of: THE APPLICATION OF WESTERN) KENTUCKY GAS COMPANY) CASE NO. 99-070 FOR AN ADJUSTMENT OF RATES) O R D E R On June 23, 1999, Western Kentucky Gas Company ("Western"), a d

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF WESTERN)

KENTUCKY GAS COMPANY) CASE NO. 99-070

FOR AN ADJUSTMENT OF RATES)

O R D E R

On June 23, 1999, Western Kentucky Gas Company ("Western"), a division of **Atmos** Energy Corporation, filed a general rate application based on a forecasted test year ending December 31, 2000. Western proposed an increase in revenues of $14,127,666, an increase of approximately 11.7 percent over its existing revenues.

To determine the reasonableness of the request, the Commission suspended the proposed rates for six months from their effective date pursuant to KRS 278.190(2) up to and including January 23, 2000. The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and WBI Southern, Inc. ("WBI") intervened. The Commission established a procedural schedule that afforded all parties the opportunity to file direct testimony and engage in discovery.

On December 3, 1999, the parties filed a Joint Stipulation and Settlement ("Settlement") resolving, to their satisfaction, the issues in this case. The Settlement is attached as Appendix A. On December 6, 1999, the Commission ordered the parties to file evidence in support of the reasonableness of the Settlement. The parties filed their responses to this Order on December 9, 1999. After review of the Settlement, direct testimony, extensive discovery and the information submitted by the parties to support the settlement, the Commission determined the record to be sufficient to render a decision and cancelled the hearing on Western's rate application scheduled to begin on December 14, 1999.

The parties agree that the Settlement is for the purposes of this case only and shall not be binding on the parties in any other proceeding before this Commission or in any court and shall not be offered or relied upon in any other proceeding involving Western or any other utility regulated by this Commission.

The parties urge the Commission to review and accept the Settlement in its entirety as a reasonable resolution of the issues in this proceeding. While the overall reasonableness of the Settlement is an important factor, the Commission is bound by law to act in the public interest and review all elements of the Settlement. In determining whether the results of the Settlement are in the public interest and beneficial to the ratepayers, the Commission considered the fact that the Settlement is a unanimous agreement of the parties.

After review of the Settlement, an examination of the record, and being otherwise sufficiently advised, the Commission finds that the Settlement is generally reasonable, but that certain modifications should be made. Although acceptance of the Settlement is conditioned on certain modifications, the modifications described herein should not significantly affect the agreement.

The following is a synopsis of the terms of the Settlement and together with comments and descriptions of modifications the Commission finds necessary.

1. The parties agree that Western will receive additional annual revenues of approximately $9,940,000, an overall revenue increase of 8.24 percent. The rate increase will be effective December 15, 1999 and will be allocated among Western's customer classes as follows:

Residential	$ 6,238,259
Commercial	2,385,006
Industrial	901,580
Other revenues	415,089

In determining the overall reasonableness of the proposed increase in annual revenues, the Commission has evaluated all revenue and expense adjustments proposed by Western in light of its traditional rate-making treatment. In addition, it has considered the current economic conditions and the rates of return on common equity that have been authorized in recent cases. Based on a review of all these factors and the evidence of record, the Commission finds that the $9,940,000 revenue increase will result in earnings that fall within a range reasonable to both Western and its customers and result in rates that are fair, just and reasonable. The Commission finds the rates included in Exhibit A of the Settlement, which is attached as Appendix B of this Order, to be fair, just and reasonable. However, we find the effective date of the rates agreed to by the parties of December 15, 1999 to be untenable. Therefore, the effective date of the rates should be for services rendered on and after the date of this Order.

2. Western will recover its demand side management program expenses prospectively for three years beginning in January 2000.

3. Western will adjust and establish certain non-recurring charges, including a new late payment charge of 5 percent applicable to all customers served under Rate G-1 that fail to pay for services by the due date shown on their bill. Western will implement this late payment charge in April of 2000. This will provide Western sufficient time to educate its customers on

this new provision. The Commission finds that, in order for it to be familiar with Western's education program and be better prepared to respond to possible customer inquiries, all educational materials should be submitted to the Commission at the same time they are disseminated to Western's customers.

4. Western will implement, as a pilot program for a period of five years, the weather normalization adjustment ("WNA") tariff included in its application, commencing November 1, 2000. Under the terms of the Settlement, Western will submit a monthly report to the Commission summarizing the effect of its WNA on customer bills by cycle for each customer class as well as actual and normal degree days and the number of days in a normal cycle. In addition Western will report a WNA factor and actual total revenues for each cycle.

The Commission finds that a greater amount of information than Western proposes to file on the WNA is necessary, but finds that annual reports, rather than monthly reports, should be filed. Western should file annual reports on the WNA, including the information set out in Appendix C, as soon after each heating season as possible but no later than June 30th of the following summer.

The Commission finds that the commencement date of November 1, 2000 affords Western an opportunity to educate its customers on this new provision and that Western should prepare and disseminate information on this new provision to its customers no later than 90 days prior to the implementation. The Commission further finds that all educational materials and information disseminated by Western to its customers on the WNA should be filed with the Commission for the same reasons enumerated above in Paragraph 3.

Should Western wish to continue the WNA pilot beyond the five year period or implement the WNA on a permanent basis, Western should make such a request in the form of a formal application to be submitted to the Commission when it files its annual WNA report in June 2005.

5. Western will adjust its base customer charges as follows: (1) the residential customer charge will increase from $5.10 to $7.50; (2) the commercial customer charge will increase from $13.60 to $20.00; and (3) the industrial customer charge will increase from $150.00 to $220.00.

6. Western will implement the industrial margin loss recovery ("MLR") mechanism proposed in its application with one modification. Per the terms of the Settlement the parties agree on a 50-50 sharing of the lost revenue between shareholders and residential customers rather than the originally proposed sharing ratio of 10-90. Western will make semi-annual filings with the Commission, in January and July, that reflect the discounts implemented during the six months ended November and May, respectively.

The Commission finds that this proposal is one of first impression before this Commission and, as such, should be implemented as a pilot for a period of three years. Western should file semi-annual reports on the MLR with the Commission as agreed to in the Settlement with the first report filed in July 2000 reflecting all discounts implemented from the date of this Order through May of 2000. Should Western wish to continue the MLR pilot beyond the three year period or implement the MLR on a permanent basis, Western should make such a request in the form of a formal application to be submitted to the Commission when it makes its semi-annual MLR filing in July 2003.

The Commission finds that there is an unintended discrepancy between the text of the Settlement and the MLR tariff as to the applicability of the 50-50 sharing of lost revenues. Per the MLR tariff attached to the Settlement the 50-50 sharing of lost revenues is to be between the shareholders and all G-1, G-2, LVS-1 and LVS-2 customers. The proposed MLR tariff in Western's application also identified these rate classes as the classes that were to share in the lost revenues. The sharing of lost revenues is approved to apply to all customers served under these rate schedules, as stated in the tariff at Tariff Sheet 29L, not to residential customers only.

7. Western will separate its gas cost from base rates by bifurcating its commodity charge into a distribution charge and a gas charge. However, the parties agree that Western is not bound by this provision in future cases.

8. Western will begin filing its gas cost adjustment on a quarterly basis beginning with the first quarter following the Commission's ruling on the Settlement.

9. Western will begin collecting a Gas Research Institute research and development surcharge.

10. Western will modify its proposal on the Alternative Receipt Point T-5 Tariff. It will change the net monthly rate of $0.10 per Mcf it originally proposed to a $50.00 monthly administrative fee per customer. The fee will be waived if, during the month, the Alternate Receipt Point represents the only point of receipt utilized by the customer.

11. With regard to the interconnection of the East Diamond Field into Western's system, WBI or its subsidiary Kentucky Pipeline and Storage Company will contract for and install facilities in accordance with Western's specifications. Western will take title to the facilities and operate and maintain the facilities as the parties agree to and outline in a finalized interconnection agreement.

IT IS THEREFORE ORDERED that:

1. The Settlement set forth in Appendix A to this Order is hereby incorporated into this Order as if fully set forth herein.

2. The terms and conditions set forth in the Settlement are approved as modified in this Order.

3. The rates and charges, and all other tariff changes included in Exhibit A of the Settlement and attached hereto as Appendix B to this Order are fair, just and reasonable and are approved for service on and after the date of this Order.

4. Any party wishing to exercise its right to withdraw from the Settlement because of modifications ordered herein shall notify the Commission in writing of its intent within 10 working days of the date of this Order.

5. If the Settlement is withdrawn due to any party's withdrawal from the Settlement, this Order will be vacated.

6. Western shall disseminate educational materials to its customers on the WNA beginning

at least 90 days before its implementation on November 1, 2000.

7. Western shall file annual reports on the WNA as soon after each heating season as possible but no later than June 30th of the following summer in the format shown in Appendix C.

8. Western shall provide the Commission with all educational materials it provides its customers with regard to the late payment penalty and the WNA at the time such materials are provided to its customers.

9. Should Western seek to continue the WNA beyond the pilot period it shall do so only after filing a formal application requesting Commission approval of its proposal to continue the WNA.

10. The MLR proposed in the Settlement is approved as a pilot program for a period of three years and shall be applicable to all customers served under Western's G-1, G-2, LVS-1 and LVS-2 rate schedules.

11. Western shall file its first MLR report with the Commission in July 2000. The July 2000 MLR report shall reflect all discounts implemented from the date of this Order through May 31, 2000.

12. Should Western seek to continue the MLR beyond the pilot period it shall do so only after filing a formal application requesting Commission approval of its proposal to continue the MLR.

13. Within 20 days from the date of this Order, Western shall file with the Commission revised tariff sheets setting out the rates and tariffs approved herein for service rendered on and after the date of this Order. These tariff sheets shall show their date of issue, the effective date, and that they were issued by authority of this Order.

Done at Frankfort, Kentucky, this 21st day of December, 1999.

By the Commission

ATTEST:

Executive Director

Document Properties

Author:	PSCUSER
last saved by:	Lewis, Kathy
revision number:	2
company:	Public Service Commission

ATMOS ENERGY CORPORATION

Gas Cost Adjustment
Rider GCA

1. Applicable

Gas Tariffs in effect for the entire Service Area of the Company as designated in the particular tariff.

2. Gas Cost Adjustment (GCA)

The Company shall file a Quarterly Report with the Commission which shall contain an updated Gas Cost Adjustment (GCA) at least thirty (30) days prior to the beginning of each quarter. The quarterly GCA shall become effective in the months of February, May, August, and November. The GCA shall become effective for meter readings on and after the first day of the quarter. The Company may make out of time filings when warranted.

3. Determination of GCA

The amount computed under each of the rate schedules to which this GCA is applicable shall be increased or decreased at a rate per Mcf calculated for each billing quarter in accordance with the following formula as applicable to each rate class:

$$GCA = EGC + CF + RF$$

Where:

EGC – is the weighted average Expected Gas Cost per Mcf of gas supply which is reasonably expected to be experienced during the quarter the GCA will be applied for billings.

ATMOS ENERGY CORPORATION

Gas Cost Adjustment
Rider GCA

EGC is composed of the following:

1) Expected commodity costs of all current purchases at reasonably expected prices, including all related variable delivery costs and FERC authorized charges (i.e., take-or-pay, transition costs, etc.) billed to the Company on a commodity basis.

2) Expected non-commodity costs including pipeline demand charges, gas supplier reservation charges, and FERC authorized charges (i.e., take-or-pay, transition costs, etc.) billed to the Company on a non-commodity basis.

3) The cost of other gas sources for system supply (no-notice supply, Company storage, withdrawals, etc.).

Less

4) The cost of gas purchases expected to be injected into underground storage.

5) Projected recovery of non-commodity costs and Lost and Unaccounted for costs from transportation transactions.

6) Projected recovery of non-commodity and commodity costs from LVS-1 and LVS-2 transactions.

7) The cost of Company-use volumes.

8) Projected recovery of non-commodity costs from High Load Factor (HLF) demand charges.

CF - is the Correction Factor per Mcf which compensates for the difference between the expected gas cost and the actual gas cost for prior periods.

The Company shall file an updated Correction Factor (CF) in its January, April, July, and October GCA filings, to become effective in February, May, August, and November respectively.

RF - is the sum of any Refund Factors filed in the current and three preceding quarterly filings. The current Refund Factor reflects refunds received from suppliers during the reporting period. The Refund Factor will be determined by dividing the refunds received plus estimated interest[1], by the annual sales used in the quarterly filing less transported volumes. After a refund factor has remained in effect for twelve months, the difference in the amount received and the amount refunded plus the accrued interest[1] will be rolled into the next refund calculation. The refund account will be operated independently of the CF and only added as a component to the GCA in order to obtain a net GCA. In the event of any large or unusual refunds, the Company may apply to the Commission for the right to depart from the refund procedure herein set forth.

[1] At a rate equal to the average of the "3-Month Commercial Paper Rates" for the immediately preceding 12-month period less ½ of 1% to cover the costs of refunding as stated in the KPSC Order from Case No. 7157-KK. These monthly rates are reported in both the Federal Reserve Bulletin and the Federal Reserve Statistical Release.

4. High Load Factor (HLF) Option

Customer with daily contract demands for firm service of 240 Mcf or greater may elect to contract for High Load Factor (HLF) service and will be applicable to G-1, LVS-1, and T-2/G-1 services.

The HLF option provides for billing of the non-commodity costs in the EGC applicable only to firm service on the basis of daily contract demand rather than on a commodity basis.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 182
Witness: Bernard Uffelman

Data Request:

Please provide the zero-intercept study referred to on page 10 of Mr. Uffelman's testimony.

Response:

The zero-intercept distribution mains regression analysis is shown on Sheets 6 and 7 of the Kentucky class cost of service study as filed by Atmos Energy Corporation Kentucky Division. The regression analysis is also included in the electronic class cost of service study (i.e., excel workbook tabs labeled "6 Mains" and "7 Mains") provided in response to the Attorney General's Initial Data Request, Question No. 175.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 183
Witness: Bernard Uffelman

Data Request:

Has the Company implemented the "minimum size" methodology described by Mr. Uffelman on page 9 of his testimony? If not, please identify the historic unit cost of the minimum size main on the system and the total feet of main currently in the Company's Kentucky system.

Response:

No. The Atmos Energy Corporation Kentucky Division utilized the zero-intercept or zero-inch linear regression analysis to determine the customer and demand components of distribution mains in the class cost of service study (CCOS) as stated on page 10, line 6 of Mr. Uffelman's testimony. The Atmos Energy Corporation Kentucky Division considers two-inch main size to be the distribution mains system minimum for the Kentucky system. The distribution mains footage and historical unit costs for each size of distribution main is shown on Sheet 6 columns 3 and 5 for the 12 month study period ended August 31, 2006 of the CCOS study.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 184
Witness: Bernard Uffelman

Data Request:

Please identify and provide the Commission orders approving the zero-intercept methodology described by Mr. Uffelman on page 10 of his testimony.

Response:

As stated on page 10, lines 12 and 13 of Mr. Uffelman's testimony, the Kentucky Public Service Commission (KPSC) approved the use of the zero-intercept analysis in the Atmos Energy Corporation Kentucky Division's 1990 rate proceeding in Case No. 90-013. Please see the attachment labeled AG DR1-184 ATT for a copy of the final order in that case.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

SEP 17 1990
RECEIVED

In the Matter of:

RATE ADJUSTMENT OF WESTERN KENTUCKY GAS COMPANY	))	CASE NO. 90-013

TABLE OF CONTENTS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

RATE ADJUSTMENT OF WESTERN KENTUCKY GAS COMPANY	))	CASE NO. 90-013

O R D E R

On February 13, 1990, Western Kentucky Gas Company ("Western") filed its notice with this Commission requesting authority to adjust its rates for gas service on and after March 15, 1990. The rates proposed by Western would produce additional annual revenues of $8,972,531, representing an increase of approximately 8 percent. In order to determine the reasonableness of Western's requested increase, the Commission suspended the proposed rates and charges until August 15, 1990.

Motions to intervene in this proceeding were filed by the Kentucky Industrial Utility Customers ("KIUC"), Kentucky Legal Services ("KLS"), National Southwire Aluminum ("Southwire"), Logan Aluminum ("Logan"), and the Attorney General by and through his Utility and Rate Intervention Division ("AG"), and Mr. Everett Brawner, a customer of Western. All were granted. A public hearing was held in the Commission's offices in Frankfort, Kentucky, on June 20-22 and June 27-28, 1990. Simultaneous briefs were filed by August 8, 1990 and simultaneous reply briefs were filed by August 15, 1990.

This Order addresses the Commission's findings and determinations with regard to Western's revenue requirements and rate design and establishes rates and charges that will produce additional annual revenues of $1,018,455 an increase of 1.0 percent over normalized test period revenues.

NET INVESTMENT RATE BASE

Western proposed a net investment rate base of $81,627,268. Western's proposed rate base includes a plant acquisition adjustment in the amount of $4,119,284 as well as a revalution of working gas storage.[1]

PLANT ACQUISITION ADJUSTMENT/DEFERRED INCOME TAXES

In November 1987, the assets of Western were acquired from Texas American Energy Corporation ("TAE"). TAE had operated Western Since 1980 as a division of its diversified gas and oil exploration and production, and natural gas distribution company. As negotiations unfolded in mid to late 1987 for the purchase, Atmos Energy Corporation, formerly Energas Company, ("Atmos") was one of the five finalists and ultimately the successful bidder for the acquisition of Western. Atmos focused all of its attention toward acquiring Western's assets, rather than the stock. However, just prior to the transfer, TAE reorganized Western as a subsidiary and consummated the sale as a stock sale. Western stated in testimony in this proceeding that the primary reason for Atmos' desire to acquire the assets from TAE was the assurance of

1 Exhibit 6, page 4.

the specific assets it was acquiring and, more importantly, the liabilities it was assuming. Atmos was particularly concerned that since TAE was in a poor financial condition and subject to bankruptcy, that it would not subject itself to liability for any other obligations of TAE. Atmos also wanted to handle the transfer as an asset purchase in order to receive the tax benefits resulting from the increase in the cost basis of the depreciable assets for tax purposes.

The transfer of Western in 1987 had two very significant impacts on the financial statements of Western which affect the revenue requirements as determined for rate-making purposes. The purchase of Western at a price in excess of the depreciated net original cost basis resulted in a utility plant acquisition adjustment of approximately $4.7 million. The other major impact on revenue requirements was the elimination of the deferred state and federal income taxes and unamortized investment tax credits of $12.8 million from the books of Western upon the transfer.

Plant Acquisition Adjustment

The plant acquisition adjustment is determined by calculating the difference in the depreciated net original cost and the purchase price of acquiring utility assets plus the acquisition costs. Western's response to Item 19 of the Commission's Order of April 24, 1990, item 19 reflected that the total acquisition cost used to determine the plant acquisition adjustment was $6 million. Western proposed to include the entire plant acquisition adjustment in the net investment rate base and to amortize the plant acquisition adjustment over 15 years.

In determining the reasonable cost of assets used to provide utility service, the Commission holds that the depreciated original cost is the appropriate standard. However, in a case involving Delta Natural Gas Company,[2] ("Delta") in 1987, the Commission allowed Delta to recover its plant acquisition adjustment. In that proceeding, the Commission established certain criteria which a utility must meet in order to justify the increased cost associated with the acquisition. The basic substance of the criteria which must be met is that the additional benefits of the acquisition in excess of book value exceeds the additional cost. These benefits related to both quality of service and economics.

In response to Item 4 of the Commission's Order dated May 30, 1990, Western addressed the criteria established by the Commission in the Delta case. Although many of the benefits are not quantifiable, Western argued that the ratepayers were realizing an immediate benefit resulting from the treatment of the gas inventory. This resulted in a rate base reduction of $3.8 million. Also, because of the deteriorating financial condition of the former owners, even though the gas distribution operations were not the cause of the financial distress, Western could have experienced increased capital costs had the transfer not taken place.

---

2 Case No. 9059, An Adjustment of Rates of Delta Natural Gas Company, Inc.

The AG argues that the plant acquisition adjustment should not be allowed because the primary reason for the acquisition adjustment is the $6 million in acquisition costs, which are excessive. The AG specifically takes issue with the $495,000 in bonuses paid to Atmos employees for their efforts in acquiring Western.

The Commission concurs with the AG's position that the acquisition costs are excessive to the extent that bonuses of $495,000 were paid to Atmos employees. While these may be valid costs incurred in connection with the acquisition, the stockholders of Atmos are the primary beneficiaries and Atmos should bear the cost of rewarding its employees for their efforts in the acquisition of Western. Therefore, the Commission has reduced the plant acquisition adjustment by $495,000 resulting in a reduction to amortization expense of $33,000 for rate-making purposes. The Commission is swayed by the uncontested arguments that cost savings will result from the change in ownership.

The Commission finds that the ratepayers and the stockholders of Atmos will both benefit from the acquisition of Western. Accordingly, the best method that will share these benefits and costs in the rate-making process is to allow the amortization of the adjusted plant acquisition adjustment in operating costs, but to exclude the acquisition adjustment from the rate base. This approach will give recognition to the additional investment to be borne by the ratepayers, but will require the stockholders to forego a return on the unamortized portion of the plant acquisition adjustment in return for the benefits they receive as a result of the acquisition.

Deferred Income Taxes

Although the purchase of Western by Atmos was technically a stock purchase, the method of recording the transfer resulted in the elimination of deferred income taxes in the amount of $12,783,597. The pre-acquisition deferred taxes were identified as Investment Tax Credits in the amount of $3,499,954 and Deferred Income Taxes of $9,283,643. In Western's rate cases prior to the transfer, rate base was reduced by the investment tax credits and the deferred taxes. The Commission has allowed full tax normalization for rate-making purposes for Western, and Western was realizing the benefits of these tax credits and deferrals prior to the transfer.

The transfer was treated as an asset purchase and the deferred taxes were eliminated by Western in the post-acquisition journal entries. Western argued throughout the proceedings that the tax attributes of the seller could not be retained by the buyer, since there was no continuing ownership interest retained by the buyer. The seller was required to treat the asset sale as a gain (or loss) for tax purposes and was liable for any taxes due, as a result of a gain, as well as any recapture of investment tax credits. Western contends that since the purchase was treated as an asset purchase, there was no way for it to retain the deferred taxes on its books. Western did not submit substantial evidence that its decision to purchase the assets rather than the stock was in the best interests of the ratepayers financially. At the hearing, Mr. Purser, Chief Financial Officer and Executive Vice President of Atmos, testified that Atmos had not done any studies comparing the financial impact on the ratepayers of acquiring the stock versus acquiring the assets of Western.

The Commission does not take issue with Western's interpretation of the IRS code requirements that the transfer, since it was in the form of an asset purchase, results in the elimination of deferred taxes. However, the election to treat the acquisition as an asset purchase, was by Atmos' choice and Atmos received various benefits by acquiring the assets, in return for the elimination of deferred taxes, such as the increase in the depreciable tax basis of the assets. The record does not indicate that the impact on ratepayers was a consideration in determining the method of acquisition.

The loss of deferred taxes and ITCs is of considerable interest to the Commission and an issue which has a significant impact on the revenue requirements in this case. In evaluating the revenue requirements effect of the elimination of these deferred taxes, consideration must be given to the sources of the deferred taxes as well as the method in which benefits are realized by the ratepayers. A knowledge of the tax deferral process is essential to a complete understanding of the issue. It should be understood that deferred taxes are considered cost-free capital to utilities. Deferred taxes are generated when income tax expense determined for book purposes exceeds income tax expense determined for tax purposes. This cost free capital is provided by the ratepayers of the utility through the tax normalization rate-making approach.

There are tax differences which are permanent and those which are the result of temporary timing differences caused primarily by differences in depreciation expense deductions for book and tax purposes. The temporary book/tax depreciation timing differences reverse in the later years of the life of the depreciable asset. Thus, the deferred taxes arising from temporary timing differences constitute a "loan" to the utility from the ratepayers, which is repaid when the book/tax timing differences reverse and the IRS tax expense is greater than the book tax expense.

There are actually three categories of deferred taxes which were eliminated in the transfer of Western. Of the $12,783,597, $3,499,954 are identified as unamortized investment tax credits. Investment tax credits are direct reductions in income tax expense at the time an investment is made in qualifying utility assets. The ratepayers incur tax expense initially as though these credits had not occurred and the excess tax payments are returned to the ratepayers over the useful life of the assets giving rise to the ITCs. These ITCs were considered a permanent tax reduction until the time of the transfer. At that point, a portion of the ITC was potentially subject to recapture, due to the sale of the assets.

The remainder of the deferred taxes consisted of deferred federal and state income taxes which would have been eliminated at the 34 percent tax rate when the book/tax depreciation timing differences reversed; and the excess deferred taxes which were created in 1978 when the maximum corporate income tax rate was lowered from 48 to 46 percent and in 1987 when the Tax Reform Act of 1986 ("TRA") lowered the maximum corporate income tax rate from

46 to 34 percent. The elimination of the deferred taxes required to offset tax expenses when the book/tax timing differences reverse were a temporary loss to the ratepayers upon the transfer of Western, whereas the elimination of the excess deferred taxes result in a permanent loss to the ratepayers.

Temporary Losses. The Commission concurs with Western's contention that the deferred taxes previously created by book/tax depreciation timing differences will be restored through greater deferrals subsequent to the transfer. The purchase of Western by Atmos and the increase in the depreciable tax basis eliminated the book and tax depreciable basis difference which had given rise to the deferred taxes on the books prior to the transfer. The depreciable tax basis now exceeds the net depreciable book basis which will further accelerate the restoration of the deferred taxes. By adjusting rate base to reflect the temporary loss of deferred taxes, which had previously been provided by the ratepayers, the Commission is restoring the investment which is due to the ratepayers and will be provided on the books of Western over the next few years. The Commission believes that the ratepayers should not be required to wait until these deferred taxes are restored to realize the benefits for the dollars they contributed prior to the transfer. By restoring these deferred taxes through a rate base reduction now, Western will not realize the double benefit of having an increased rate base for rate-making purposes as well as a decreasing rate base and higher annual earnings through the process of restoring the deferred taxes in future years. The book effect of the rate base reduction will only be realized by Western during the period of time that the deferred taxes are not restored.

Permanent Losses. The elimination of the unamortized investment tax credits upon the transfer of Western resulted in a permanent loss to the ratepayers of funds provided for taxes. Western stated that the ITCs were subject to recapture and the seller was responsible for payment of the previously utilized tax credits. The Commission does not dispute Western's position that a portion of these ITCs would have become a tax liability of the seller upon the transfer. The fact remains, however, that the ratepayers provided the funds to cover the cost of these taxes in advance, and the action of the seller created the tax liability which would not have occurred had the transfer not occurred. There is no information in the record in this case which would allow the Commission to readily identify what component of the ITC was subject to recapture. Even if these amounts could be identified, the ITCs would not have been recaptured if the sale had not occurred. The payment of these additional taxes should be arranged in the purchase/sale transaction between the buyer and seller and the increased cost, if any, should not be borne by the ratepayers.

The excess deferred taxes resulting from the TRA tax rate reduction and the 1978 tax rate reduction, from 48 to 46 percent, should be restored to the benefit of the ratepayers. The TRA provided that the excess deferred taxes resulting from the tax rate reduction should be returned to the ratepayers using the average rate assumption method. This method would have flowed this tax benefit back to the ratepayers of Western over the remaining useful life of the assets. Upon the sale of Western, the seller was not required to remit any of these excess deferred taxes to IRS since the tax rate should not have exceeded 34 percent. Once again, the seller was responsible for taxes on its recorded gain on the sale of the assets. As with the other permanent losses, the funds were provided by the ratepayers and should not result in an increase in rate base for the ratepayer. The ratepayers did not share in the gain realized by the seller; therefore, they should not be responsible for the taxes.

Western's primary rebuttal to questions at the hearing and to the testimony of the AG regarding the elimination of ITCs and deferred taxes, was that the ratepayers would benefit from the increase in the depreciable tax basis of the assets and the deferred taxes would be restored through MACRS depreciation. This observation is true with regard to the deferred taxes which were lost temporarily; however, the investment tax credits and the excess deferred taxes will not be restored and will result in a permanent loss to the ratepayers. The Commission finds that the ratepayers should not bear the loss of these deferred taxes. Therefore, an adjustment should be made, for rate-making purposes, to restore the liability and refund these losses to the ratepayers. For rate-making purposes, the temporary losses and permanent losses are treated differently. The temporary losses should be deducted from rate base with no amortization, since these deferred taxes will be restored. The permanent losses should be deducted from rate base and amortized over the remaining book life of the assets at the time of the transfer. This will, in effect, provide the same rate-making impact that would have occurred without the transfer.

The Commission's decision on the loss of investment tax credits and deferred taxes results in a reduction to rate base of $12,783,597 and a reduction to income tax expense of $233,330 for amortization of the investment tax credits and a reduction to income tax expense of $131,081 for amortization of the excess deferred taxes. The amount of excess deferred taxes was estimated by applying 26 percent to the level of deferred taxes on the books at the time of the transfer. The 26 percent factor represents the change in the maximum corporate income tax rate from 46 to 34 percent.

Valuation of Working Gas

Western proposed to increase its rate base by $2,801,235 in order to revalue its working gas storage to reflect the Texas Gas Zone 3 price as established in Western's Gas Cost Adjustment Case No. 9556-M[3] ("GCA 9556-M").[4]

The AG proposed a reduction of $1,818,257 in the working gas storage balance based on the premise that a portion of the gas remained in storage throughout the test period.[5] Since the entire

---

3 Case No. 9556-M, Notice of Purchased Gas Adjustment Filing of Western Kentucky Gas.

4 Exhibit MSL-8, page 4.

5 DeWard Prefiled Testimony, page 21.

amount of working gas was not withdrawn from storage, the value of the gas stored will never equal the current price used by the company to price out the gas. The AG therefore argues that Western should value working gas inventory by excluding the amount at the point of the lowest storage level, that being at April 30, 1989. The AG's proposal would reduce the rate base by $1,818,257.[6]

KLS proposed that Western's adjustment to its working gas storage should be eliminated completely because it does not reflect a known and measurable change.[7] In support of its position, KLS states: 1) the adjustment is based upon an estimate; 2) the estimate varies over time; 3) the gas purchased will not necessarily be the gas stored; and 4) the adjustment will lock into rates an estimated gas cost despite the certainty that this cost will fluctuate.[8]

According to Western's response to an interrogatory during discovery and during cross-examination, Western's witness stated that its underground storage is priced at average cost. Western's witness further states that Western is asking for a return on inventory that is valued at the higher of the average cost and

---

6 Exhibit TCD-1, Schedule 6.

7 Brief of KLS, page 5.

8 _Id._, page 4.

the Texas Gas Zone 3 price.[9] The Commission believes it to be inappropriate for Western to revalue its inventory for rate-making purposes at a value higher than its cost; and although the KLS proposal has merit, the Commission believes that an average rather than the test-period-end valuation is the more appropriate method because an average will account for any abnormalities that may occur during the test period. The Commission finds that the AG's proposal for revaluation is the more appropriate method.

Cash-Working Capital Allowance

Western proposed, as a component of its rate base, a cash-working capital allowance of $2,864,951.[10] Western derived this amount based on the 1/8 formula method.

The AG has proposed a complete elimination of this adjustment because the formula method "always produces a working capital allowance, but does not produce an amount which truly represents a working capital requirement."[11] The AG further states that Western has not justified its need for a cash-working capital requirement.

The Commission is aware of the AG's position regarding the 1/8 formula method for determining a cash-working capital allowance; however, the Commission is not persuaded to abandon the formula method in this case and will allow Western to calculate

---

9 T.E., Vol. IV, page 25.

10 Exhibit 6, page 4.

11 DeWard Prefiled Testimony, page 23.

its cash-working capital requirement in this manner. The Commission, however, will reduce Western's proposed cash-working capital requirement by $150,272 to reflect the level of operation and maintenance expenses found reasonable in this case.

Computer Equipment

Included in Western's plant in service component of its rate base is computer equipment in the amount of $2,158,659 that was sold subsequent to the test period. Also included was associated accumulated depreciation in the amount of $1,181,331. The record in this proceeding indicates that the computer equipment was located at Western's office in Owensboro and was sold in February 1990.[12]

The AG contends that since the computer has been sold, Western should not be allowed a return on the equipment and should not be allowed to recover the associated depreciation expense.[13]

Western stated that although the equipment had been sold and was no longer in service, it was the only computer system on which the company was seeking a return and a recovery of costs.[14] Western's witness testified that no costs from the corporate data processing functions nor any actual test-period costs that had been removed during the test period are included in this proceeding.[15]

---

[12] Brief of Western, page 35.

[13] DeWard Prefiled Testimony, page 14.

[14] Brief of Western, page 36.

[15] T.E., Vol. III, page 213-214.

The Commission is very concerned about allowing any utility to earn a return on plant that is not only no longer in service, but is no longer owned by the utility. On the other hand, the Commission would be hesitant to not allow a utility to recover a properly incurred cost of operations. Western has stated in its brief that at the time of its filing of this case, neither the timing of the sale nor the proper amount to be allocated by the corporate office was known.[16] If the Commission disallowed Western recovery of the computer that was sold, it would be, in effect, barring Western from recovering most of its data processing costs. The Commission believes that Western should be allowed the return on the equipment that was sold and finds that Western has included an appropriate amount in its rate base for computer equipment.

<u>12-Month Average for Underground Storage</u>

The AG proposed a $275,436 reduction to Western's rate base using a 12-month average to value Western's gas stored underground as opposed to the usual 13-month. The AG's rationale for this proposal is that the inclusion of 13 months artificially inflates the balance by using two of the three highest month balances of the period.[17]

This Commission has generally used the 13-month average for gas inventory and other rate base components as well as revenue and expense items. The basis for use of the 13-month average is

---

16 Brief of Western, page 35.

17 DeWard Prefiled Testimony, page 22.

to dilute any abnormalities that may occur during the test period and to include the average for the appropriate time span. The Commission is not persuaded to abandon the 13-month average in this case.

Construction Work in Progress ("CWIP")

The AG proposed that Western's rate base be reduced by $107,341 to remove CWIP for which Western is expected to be reimbursed.[18] The Commission agrees.

Western contends that it is not known if the company will actually receive reimbursement for these items, but stated that it was subject to reimbursement of these items.[19]

Rate Base Determination

Based upon the above discussion, the Commission has determined Western's net investment rate base at September 30, 1989 to be $63,401,818, determined as follows:

Gas Plant in Service	$119,822,147
Construction Work in Progress	693,488
Gas Stored Underground	1,775,865
	$122,291,500
Deduct:	
Accumulated Depreciation	(57,995,843)
Transfer Related Deferred Tax Losses	(12,783,597)
Retirement Work in Progress	(189,566)
Customer Advances for Construction	(3,398,193)

18 DeWard Prefiled Testimony, page 23.

19 Response to AG Data Request, March 30, 1990, Item 9.

Add:	
Cash-Working Capital Allowance	2,714,679
Prepayments	699,813
Materials and Supplies	997,337
LP Gas Inventory	68,482
Working Gas Storage	10,997,206
Total Net Investment Rate Base	$ 63,401,818

CAPITAL STRUCTURE

Western proposed a capital structure of 50.58 percent debt and 49.42 percent common equity based on the actual end-of-test-year capital structure of Atmos, divided between long-term debt and equity. Western did not include in its capital structure short-term debt of $31,600,000 which was outstanding at the end of the test period, stating that "the capital structure of Atmos is reasonable excluding short-term debt" and "short-term debt is not permanent and regularly has to be retired and replaced."[20]

The AG proposed a capital structure of 50.00 percent long-term debt, 8.50 percent short-term debt, and 41.5 percent common equity. The AG proposed to include the average daily balance of short term debt for the test year of $15,880,500 in the capital structure, and also proposed to include $14,000,000 of additional long-term debt because this commitment was made prior to the end of the test year and an initial placement was made within 11 days of the test year.

The Commission finds that the adjusted capital structure as recommended by the AG is reasonable with one exception. The AG's proposed amount of short-term debt of $15,880,500 differs slightly

20 Response to Commission's Order dated April 24, 1990, Item 35.

from the average daily amount of $15,858,356 provided by Western; the Commission accepts the amount provided by Western as correct. The capital structure should reflect short-term debt because Western uses significant amounts of short-term debt on an ongoing basis and the additional $14,000,000 long-term debt issuance should be reflected in the capital structure because it is known and measurable and occurred shortly after the end of the test period. Therefore, for rate-making purposes the capital structure for Western should be as follows:

	Amount	Percent
Long-Term Debt	$ 93,552,812	49.99
Short-Term Debt	15,858,356	8.47
Common Equity	77,730,000	41.54
	$187,141,168	100.00

REVENUES AND EXPENSES

Western reported test-period operating income of $10,369,695.[21] In order to normalize current operating conditions, Western proposed several adjustments to revenues and expenses which resulted in adjusted operating income of $4,710,874.[22]

Revenue Normalization

Western proposed normalized gas operating revenues of $112,477,915 based on the rates in effect at the time the application was filed. This amount consisted of $78,077,942 in gas cost revenues and $34,399,973 in base rate revenues. Though not an issue in this case, the total amount of gas cost revenues

21 Exhibit 5, page 1.
22 Exhibit 6, page 3.

is a major component of Western's revenues and its rates. The rates authorized in this case will include gas cost recovery of $67,027,082, reflecting Western's latest gas cost adjustment effective August 1, 1990.[23] Purchased gas cost has been adjusted in a similar manner to reflect Western's current cost of gas.

In normalizing its revenues, Western increased its sales and transportation volumes by 423,890 Mcf and 12,321 Mcf, respectively, to reflect its adjustment for weather normalization. Western decreased its sales volumes by 39,500 Mcf and increased transportation volumes by 165,100 Mcf to reflect normalized deliveries to large volume industrial customers. The Commission finds Western's adjustments to be reasonable and accepts Western's normalized base rate revenues.

Merchandise Sales and Jobbing

The AG proposed that Western's net income be increased by $322,784 by moving net income associated with merchandising and jobbing above the line.[24] The AG contends that there has not been a proper allocation of the expenses below the line and it is, therefore, inappropriate to include the income below the line. Western maintains that it has properly recorded both the revenues and expenses, per the Uniform System of Accounts ("USoA"), for the

---

23 Case No. 9556-O, Gas Cost Adjustment Filing of Western Kentucky Gas Company, Order dated August 1, 1990.

24 DeWard Prefiled Testimony, page 24.

merchandising and jobbing and that the AG had ample opportunity to examine the books and ledgers and to determine if Western had correctly recorded revenues and expenses.[25]

Upon thorough analysis, the Commission believes that Western has not properly segregated the expenses associated with merchandise sales and finds Western's test-period revenues should be increased by $322,784, resulting in an increase to net operating income of $195,462.[26] The expenses are discussed in more detail in another part of this Order.

Amortization Expense

Based upon treatment of the acquisition adjustment as discussed in a previous section of this Order, the Commission finds that Western's proposed amortization expense should be reduced by $33,000, resulting in an increase to net operating income in the amount of $19,983.

Employee Dinners and Awards

Western proposed to include in test-period expenses an amount of $109,086 for employee service awards and dinners.[27] Included in this amount is approximately $55,000 for Rolex brand watches given to 16 employees with at least 30 years of service.[28]

---

25 Lovell Rebuttal Testimony, page 35.

26 $322,784 x .60555 (tax factor) = $195,462.

27 Brief of Western, page 70.

28 Lovell Rebuttal Testimony, page 15.

The AG proposed to disallow the entire amount as excessive and inappropriate expenditures that should not be borne by the ratepayers.

This Commission has in the past allowed reasonable levels of expenditures for employee service awards. However, the Commission believes that in this case Western's expenditures are excessive. The Commission does not object to Western or any utility rewarding its employees for their service, but believes utilities should use discretion in their expenditures. The Commission does not believe that the ratepayers of Western should be forced to provide premium watches for Western employees. The Commission finds that such an expense should be borne by Western's shareholders and therefore reduces Western's test-period expenses by $55,000, the cost of the premium watches. The Commission will allow the remainder of the service awards and dinners. This results in an increase of $33,305 to Western's net operating income.

Aircraft Charges

Western included $185,899 in aircraft expenses allocated to Western. The AG proposed to eliminate the charges since Western no longer leases aircraft and the charge will be nonrecurring.

Western has stated that although the company no longer leases aircraft, the expense has been replaced by commercial airfare.

The Commission notes that there were significant charges in the test period for commercial and charter aircraft and the allocated charges to Western were in addition to charges that were directly charged to Western. The Commission finds that the test period contained adequate charges for aircraft and due to the non-recurring nature of the allocated charges, Western's test-period expenses should be reduced by $185,899, the total allocated aircraft charges. This increases Western's net operating income by $112,571.

Country Club Charges

A total of $68,333 of expenditures in the test period were identified by various parties as country club dues or country club related charges.[29]

This Commission has in the past found that such charges should be borne by shareholders and not the ratepayers. The Commission so finds in this case and will reduce Western's operating expenses by $68,333, resulting in an increase to net operating income of $41,379.

Outside Services

The AG contends that Western's operating expenses should be reduced by $132,133 to eliminate expenses paid for temporary clerical services, principally provided by Kelly Services. The AG claims that these expenses are not necessary and are non-recurring.[30] The AG further states that the expenses are duplicative because the expenses are recorded elsewhere. The AG also claims that Western's annualized payroll includes amounts for

29 Exhibit TCD-1, Schedules 40, 41, and 42.

30 DeWard Prefiled Testimony, page 39.

employee salaries when actually some employees leave and are not immediately replaced.[31]

Western argues that the expenses are necessary and that they are an ongoing business expense.[32]

The Commission believes that there is some duplication of expenses because Western has been provided reasonable levels of wage expense and overtime and has failed to show that the temporary services provided do not duplicate work provided by Western's regular staff. The Commission, therefore, finds that Western's expenses should be reduced by $132,133, resulting in an increase to net operating income of $80,013.

Consultant Fees

The AG proposed that the consulting fees paid to C. R. Hayes, the retired president of Western, for the test period be disallowed. The AG's argument was that Mr. Hayes now resides outside of Western's operating area and over time the value of his services to Western will diminish.

Western contends that its decision to retain Mr. Hayes as a consultant was wise and prudent because of his extensive knowledge of the Western system.

This Commission has no doubt that Mr. Hayes provided Western a very valuable service and that his extensive knowledge and experience regarding Western's operations proved very valuable to

---

31 Id.

32 Brief of Western Kentucky Gas, page 63.

Atmos in the time immediately subsequent to the acquisition. However, the Commission feels that over time Mr. Hayes' services to Atmos will not be necessary and that to continue to allow recovery through rates of compensation to Mr. Hayes would be inappropriate. The Commission therefore reduces Western's operating expenses by $33,487 for consulting fees paid to Mr. Hayes and country club charges incurred on his behalf. This action increases Western's net operating income by $20,278.

Audit Accruals

The AG proposed a reduction of $48,000 to Western's operating expense. The amount is the result of Western being assigned audit expense from the corporate level because Western maintained a separate ledger. Beginning January 1, 1990, Western no longer maintains a separate ledger and the AG argues that the charge will be nonrecurring and should be removed from test-period operations.[33]

Western states that although its ledger is now combined with the other operating divisions and the cost will in the future be allocated to Western, the costs of audits, in this case, are not included in its proposed allocations from the general office. Since this cost will continue on an annual basis, as an

[33] DeWard Prefiled Testimony, page 35.

allocation, an amount for this expense should remain in the test period.[34]

Since Western did not make a provision to include the amount in its general office allocations, the Commission finds that it is reasonable to allow the charge in test-period operations.

Intracompany Payroll Charges

A reduction to Western's test-period operating expense was proposed by the AG for charges by Atmos to Western for the services of two Atmos employees included on Western's payroll. Western has stated that it agrees with the AG's proposal.[35]

The Commission finds the expenses unreasonable. Western's operating expenses should be reduced by $134,194 to reflect the removal of these charges. This results in an increase of $81,261 to Western's net operating income.

Payroll

Western proposed to increase from 83 percent to 88.6 percent the level of wages expensed, thus reducing the level of wages capitalized. The proposal is based on an accounting change that allows capitalization of administrative and general expense ("A&G") at the corporate level and discontinues capitalization of such charges at the division level.[36]

---

34 Brief of Western, page 59.

35 Brief of Western, page 60.

36 Lovell Prefiled Testimony, page 18.

The AG proposed that Western be allowed to increase its percentage of capitalized wages from 83 percent to 83.54 percent. The AG also proposed that Western's annualized wage levels be adjusted to reflect work force reductions that occurred in February 1990.[37]

Western has accepted the AG's proposal to adjust the annualized wage levels due to subsequent work force reductions.[38] However, Western takes issue with the AG proposal to decrease Western's percentage of wages to be expensed. Western states that A&G functions have moved away from the division level and these duties are now more appropriately performed at the corporate level. Since the functions are being performed at the corporate level, the costs should be capitalized at that level.

The Commission agrees that if the costs are being incurred at the corporate level, they should be capitalized at that level and the appropriate allocation made to the division. The problem that the Commission finds is that if services are transferred from the division level to the corporate level, and costs should follow, then it would stand to reason that costs at the division level should decrease. According to Western, the A&G expenses at the division level were merely reclassified from A&G expenses to distribution costs.[39] Western did not indicate that costs at the division level would decrease, but that the amount allocated to

---

37 DeWard Prefiled Testimony, page 37.

38 Brief of Western, page 61.

39 T.E., Vol. IV, page 30.

Western from Atmos would decrease.[40] The Commission, for these reasons, rejects Western's proposal and will reduce operating expenses by $682,853, the amount proposed by the AG. This will increase Western's net operating income by $413,502.

Payroll Taxes

Based on the above adjustment to payroll, the Commission finds that Western's payroll taxes should be reduced by $51,282, the amount proposed by the AG, thus increasing net operating income by $31,054.

Demonstration and Selling Expense

The AG proposed to reduce Western's demonstration selling expense, Account 912, by $664,895. This amount includes the entire test-period amount in Account 912 with the exception of an allowance for the salaries of two marketing representatives.[41] The costs included in Account 912 are broken down as follows: (1) builders' trip to San Francisco, $47,146; (2) Affordable Gas Home Program, $169,391; (3) Customer on the Main Program, $160,055; and (4) Labor costs of $250,965.[42] In addition, there were other costs identified as gift certificates and incentives to encourage the use of gas appliances. The AG's arguments revolves around 807 KAR 5:016, Section 4. This regulation deals with the subject of

---

40 Id.

41 DeWard Prefiled Testimony, page 45.

42 AG Data Request, March 30, 1990, Item 77.

disallowed advertising. The AG contends that the charges in Account 912 constitute disallowed advertising under 807 KAR 5:016 (4).

Western states in its brief that the expenses incurred and recorded in Account 912 do not constitute promotional advertising as defined in KAR 5:016.[43] Western contends that 807 KAR 5:016, Section 4(1)(d), allows the type of activity that gave rise to the expenditures recorded in Account 912, and that portion of the regulation defines what is not promotional advertising.

The USoA does not classify Account 912 expenditures as advertising. The Commission does believe that some of the expenses in Account 912 should be disallowed on the basis that they constitute promotional advertising. In addition, the USoA excludes any demonstration and selling expenditures from Account 912 that were incurred as a result of merchandising activity by the utility. Western has failed to show that it segregated the labor costs and other expenses associated with merchandising and jobbing from appropriate above the line expenses. For the above reasons, the Commission will not allow any of the Account 912 expenses for rate-making purposes. In any case, this Commission would have disallowed the cost of the San Francisco builders' conference. This cost should not be borne by the ratepayers. The reduction of expenses by $721,223 increases net operating income by $436,737.

---

43 Brief of Western, page 77.

Heat Pump Advertising

The AG proposed a reduction of $86,881 to Western's operating expenses for the removal of costs related to heat pump advertising.

The expenses incurred for heat pump advertising are clearly prohibited by regulation. 807 KAR 5:016, Section 4(1)(b), reads:

> Promotional advertising means any advertising for the purpose of encouraging any person to select or use the service or additional service of an energy utility, or the selection or installation of any appliance or equipment designed to use such utility's service. (emphasis added)

Advertising designed to persuade consumers to switch from electric heat pumps to gas furnaces constitutes promotional advertising, and expenses incurred for such advertising are prohibited for rate-making purposes. The Commission, therefore, reduces Western's operating expenses by $86,881, thereby increasing net operating income by $52,611.

Miscellaneous Sales Expense

Western included in its Miscellaneous Sales Expense $35,735 for a trip to Las Vegas for employees who achieved certain sales levels for gas grills and yard lights.

Also included is $1,900 for twenty season tickets to basketball games for Kentucky Weslyan College.

The AG has proposed removal of the above expenses.

The costs of the Las Vegas trip should be disallowed. Any benefit that the ratepayers may have derived from this conference could have been accomplished by less expensive means. In addition, the Commission believes that the cost of this campaign constitutes promotional advertising and should be disallowed. The Commission, therefore, finds that the costs should not be borne by Western's ratepayers and has reduced Western's operating expenses by $35,735. Further, the Commission finds that Western's operating expenses should be reduced by an additional $1,900 spent for Kentucky Weslyan basketball tickets. The Commission finds ratepayers should not bear the costs of attendance to athletic events by utility employees.

The result of the above adjustments increases Western's net operating income by $22,790.

<u>LP Gas Expense</u>

The AG proposed removal of $4,836 of costs associated with Western's liquefied petroleum gas ("LP Gas") expense. It is the AG's contention that such costs are recovered through Western's quarterly gas cost adjustment.

Western contends that the AG is wrong and that the expense is not recovered through the gas cost adjustment.

The Commission finds that Western does recover such costs through the CGA and will allow the AG's proposed adjustment. This will increase net operating income by $2,928.

<u>Direct Payments to Western Employees</u>

The AG proposed a reduction to Western's operating expenses to remove expenditures that were made directly to Western employees. The AG provided no support for this proposal other than to state it allowed full annualization of wages.[44]

---

44 DeWard Prefiled Testimony, page 40

Western has stated that the payments were to reimburse employees for expenses they incurred while performing their job duties and are not a part of the employees' compensation.[45]

The Commission finds the expenditures were appropriate.

Group Insurance

The AG proposes to reduce Western's test-period expenses by $269,787 to reflect an adjustment to group insurance expense. The AG reached this conclusion by annualizing one month of billings and adding that number to the actual claims paid for the test period.[46]

Western's witness established that the difference in the company proposal and the actual test-year expenditures was approximately $8,000.[47]

It is not reasonable to base a proposal on one month annualized. Western has provided a much more appropriate number based upon the test-period actual.

Supplemental Retirement Benefits

The AG proposed a reduction of $64,166 in retirement benefits given to what the AG refers to as "certain key employees."[48] The AG offered no other support for the proposal and as such the Commission finds it to be without merit. The supplemental

---

45 Lovell Rebuttal Testimony, page 36.

46 Exhibit TCD-1, Schedule 23.

47 Exhibit MSL-16.

48 DeWard Prefiled Testimony, page 42.

retirement benefits are reasonable and an allowable rate-making expense.

Personal Use of Company Automobiles

The AG objected to Western's inclusion in rates its expense in furnishing automobiles to some of its employees while allowing personal use of these autos. The AG simply states that the costs should not be borne by the ratepayers, but offers no insight as to why.[49]

The Commission has in the past allowed such costs as reasonable and is not persuaded to change in this proceeding.

Benefits

Western proposed to increase its benefits expense by $177,703.[50] The adjustment was proposed to correspondingly increase benefits to match the increased payroll.

The AG objected to this proposal because Western provided no documentation to support the total benefits package. Western based its proposed increase upon an approximate 21 percent benefits to payroll relationship, calculated based upon historical data. The Commission finds that both Western's benefits level and the methodology employed to determine the increase to be reasonable.

Liability Insurance

The AG proposed to reduce Western's operating expenses by $263,300 to exclude the test-period costs of excess Property Loss

---

49 DeWard Prefiled Testimony, page 43.

50 Exhibit 5, page 16.

and Property Damage insurance. The AG contends that Western provided no support for the expense.[51]

The Commission finds that Western has adequately supported its position by the production of actual insurance policies that state the cost to Western. The AG has not provided adequate information and has not offered evidence of a more appropriate level of cost.

Arthur Andersen Fees

Western retained the services of the accounting firm of Arthur Andersen to assist it with the management audit. The AG proposed that the fees, in the amount of $50,970, be disallowed and states that he has proposed allowance of the full cost of the management audit to be amortized over a 3-year period.[52]

The Commission finds that Western was not unreasonable in retaining the benefit of experts to assist it with the management audit. The Commission does not feel that the fee is excessive and that Arthur Andersen provided a reasonably necessary service.

Based upon the above, the Commission finds that the fee should be allowed for rate-making purposes. The Commission will, however, require amortization of the cost over a three-year period. This action results in a decrease of $33,980 to operating expense and an increase to net operating income of $20,577.

---

51 DeWard Prefiled Testimony, page 44.

52 Id., page 49.

Attorney Fees

The AG proposed that $40,730 of legal fees incurred by Western be removed from test-period expenses because the fees represent a duplication of services.[53] Western merely changed law firms for representation of FERC matters during the test period.

The Commission finds that Western's legal fees for the test period are appropriate and should be allowed for rate-making purposes.

American Gas Association ("AGA") Dues

The AG proposed that $35,384 of expenses that represent AGA dues be removed from this rate proceeding. The AG contends that the fees are excessive based on the 1989 allocated amount and that a portion of the fees represent advertising and lobbying activities that would be disallowed for rate-making in Kentucky.[54]

Western argues that the AG inappropriately went beyond the test period by including the total amount of 1989 expenditures for comparison purposes.

This Commission has always supported membership in the AGA and the USoA allows for inclusion of AGA dues above the line. The Commission, however, does not believe that the AG's adjustment is inappropriate. The amount that the AG proposed to exclude for lobbying and advertising is reasonable. Also, Western has failed to adequately explain the difference between the allocated amount

---

53 DeWard Prefiled Testimony, page 49.

54 DeWard Prefiled Testimony, page 50.

of AGA dues and the actual expenditure. The Commission reduces Western's test-period expenses by $35,384, resulting in an increase to net operating income of $21,427.

Workers' Compensation Audit

The AG proposed disallowance of a $14,000 payment for a Workers' Compensation audit by stating that it was for a prior year's audit. The audit covered the prior year's activity but the actual audit took place during the test period and the cost was incurred during the test period. The Commission therefore finds the payment to be appropriate.

Clearing Account Balances

The AG proposed a reduction to operating expense in the amount of $107,255 attributable to excessive levels of expenses in clearing account balances. The AG states that the expenses were incurred in a prior period but were deferred to a clearing account.[55]

The majority of the clearing account balances that the AG proposes to disallow includes account 163 undistributed stores expense. It would appear that Western has properly accounted for the expenses in the clearing accounts. Western argues and the Commission agrees that the AG's proposed adjustment violates the USoA, accrual accounting principles, and creates a mismatch.

---

55 DeWard Prefiled Testimony, page 51

Relocation Expense

The AG proposed removal of $22,687 from the test period. This amount represents the loss on the sale of homes of employees that were relocated by the company.

Western argues in its brief that a proposal such as the one the AG has made would result in less than desirable circumstances because the employees would not be able to move or Western would be required to compensate the employees at a higher rate.

The Commission does not believe that the ratepayers of Western should have to bear the loss on the sale of Western employees' homes. Excluding this loss from test-period operations will increase net operating income by $13,738.

Account 921

The AG cites several charges that it claims are inappropriate for rate-making and has proposed removal of the expenses. The charges are located in Account 921, Office Supplies and Expenses, and total $11,863.[56]

After analysis of the charges, the Commission finds that some of the charges are inappropriate and they should be disallowed for rate-making purposes. Such charges include charges for golf outings, Kentucky Derby, and other expenses listed on TCD-1, Schedule 44, except the expenses for the stock promotion meetings and the management retreat. The total of the disallowed expenses is $6,129. This will increase net operating income by $3,711.

---

56 Exhibit TCD-1, Schedule 44.

Corporate Allocations

Western proposed a methodology for allocation of costs from the corporate to the division level. As a result of its proposal, Western would increase its operating expenses by $3,193,002 in order to reflect the current level of allocations.[57]

Prior to this proceeding, Atmos allocated corporate services to Western based upon the methodology used by Western's prior parent TAE. TAE allocated charges to Western in the amount of $332,400 annually. Subsequent to the acquisition of Western by Atmos, the allocation method used by TAE was continued as a temporary measure until Atmos could analyze and develop a more appropriate method.

The recent management audit of Western included specific recommendations concerning cost allocations. Recommendations IV-R1 provide for the development of an activity-based cost allocation system, documentation in a procedures manual, and review by the Commission prior to implementation. With minor exceptions, Western approved both recommendations and developed implementation plans.

Western's proposal calls for costs to be assigned to operating units on a direct basis whenever practical and when responsibility for the cost can be determined. Western has proposed that a business need for resources can be determined based on: (1) levels of investment, (2) business activity levels,

---

57 Exhibit 5, page 3.

and (3) human resource requirements.[58] The factors derived by Western to determine business activity levels include: (1) Assets or direct plant; (2) Mcf received into the system; (3) number of customers; and (4) the number of employees. It was then determined, based upon the above activity factors, that Western represents roughly one-third (32.53 percent) of the total Atmos assets and operating activity.[59] Based upon these factors, Atmos determined the amount of costs from each corporate department that should be allocated to the division level.[60]

The AG identified what it stated to be problems with the proposed allocation methodology. First of all, the AG stated that this Commission should undertake an audit at the Atmos corporate level basically for verification of all expenditures to determine appropriate allocation treatment.[61] The Commission does not agree that this is necessary at this time.

Some of the specific problems that the AG has with Western's proposed allocation methodology are shown on Exhibit TCD-1, Schedule 13-3. The AG believes that there are duplicate positions at each level, such as a Western president and an Atmos corporate president.[62] The AG also contends that costs that were formerly

---

58 Lovell Prefiled Testimony, page 11.

59 Id., page 12.

60 Exhibit MSL-1.

61 DeWard Prefiled Testimony, pages 8-9.

62 Id., page 28.

directly assigned to specific operating divisions are now being allocated to all divisions.[63]

In the Management Audit Action Plan Progress Report, Western indicated that implementation of the actual plan was still in progress. For the purposes of this proceeding, the Commission has accepted Western's $3,193,002 pro forma adjustments to increase operating expenses for corporate allocations; however, the Commission does not accept Western's proposed allocation methodology. Western should continue to implement the cost allocation recommendations of the management audit. It is apparent from the record that Western does not have all of the allocation procedures in place. For example, Western did not include data processing costs or audit costs in its proposed overhead allocations. Until Western has implemented all of the recommendations in the management audit that apply to the cost allocation, the Commission will not give its approval to Western's proposed methodology.

The Commission has reduced Western's operating expenses by $3,650 to reflect a subsequent revision made by Western to its initial filing thus reducing allocations. This will increase net operating income by $2,210.

Rate Case Expense

In its filing, Western proposed a level of rate case expense of $93,000. In response to requests at the hearing, Western filed

63 Id., page 28.

an updated amount of $216,309.[64] Western has proposed amortization of these costs over a two-year period.

The Commission expresses its concern with the level of costs incurred in this proceeding, but will allow the total amount. The Commission finds, however, that the costs should be amortized over a three-year period instead of two. This action increases Western's proposed operating expenses by $25,603 which decreases Western's net operating income by $15,504.

<u>Pension Expense</u>

The AG proposed a reduction to Western's test-period operating expenses in the amount of $467,605.[65] The AG bases its proposal on actuarial studies that assume Western's pension plan would not bear any of the plan's administrative costs. The AG also contends the expense should be reduced because the plan is overfunded.

Western argues that the pension costs included in this proceeding are appropriate because they are the actual costs incurred during the period. The costs include administrative costs, actual costs per FAS 87 and direct payments.[66]

The Commission notes that Western's pension fund is overfunded; however, the overfunding helps to lower the costs to the company and, therefore, the ratepayer. In addition, under

---

64 Western Kentucky Gas, Summary of Rate Case Expenses, Filed August 2, 1990.

65 DeWard Prefiled Testimony, page 41.

66 Brief of Western, page 67.

current accounting, the plan will not remain overfunded. At some time Western will be required to begin to increase its contribution. There should be no reduction.

Interest Synchronization

Based upon the rate base, capital structure, and rate of return, found reasonable by this Commission in this proceeding, the Commission has calculated an interest deduction for income tax purposes of $3,806,334, a reduction to Western's proposed interest expense of $4,252,781.[67] This results in an increase to income tax expense and a decrease to net operating income of $176,101.

Federal and State Income Tax Expense

Western proposed total federal and state income tax expense of $3,770,238. Western calculated the pro forma expense based on a Kentucky state tax rate of 7.25 percent. Subsequent to the filing of this proceeding, the rate was changed to 8.25 percent and the Commission has accordingly increased Western's income tax expense by $4,939 resulting in a decrease to net operating income of the same.

The AG proposed several adjustments to Western's income tax expense. The AG proposed a $100,000 deduction for employee stock ownership plan dividends ("ESOP"), a $50,000 adjustment for savings realized from filing a consolidated tax return, and a $950,000 deduction for depreciation on the excess of tax basis of assets over book basis.

---

67 Exhibit 5, page 1.

The AG's proposed deduction of ESOP dividends is based only on an estimated number and cannot be accepted.[68]

Regarding the AG's proposal to adjust for savings from a consolidated return, the Commission finds that since the tax expense is calculated on a going forward basis, any savings that may result is not known at this time.

Due to the treatment of the deferred tax items in the rate base section of this Order, the proposal to reduce taxes on the excess of tax basis over book basis is not necessary.

RATE OF RETURN

Cost of Debt

Western proposed a cost of long-term debt of 10.31 percent. Because Western proposed to exclude short-term debt from its capital structure, Western did not propose a cost of short-term debt. However, upon requests from the Commission, Western proposed that if short-term debt were to be included, it should be priced at the weighted average cost of capital excluding short-term debt.[69]

The AG proposed a cost of long-term debt of 10.31 percent and a cost of short term debt of 9.30 percent. The rate proposed by the AG was the average cost, calculated on a daily basis, at the end of December 1989.

The Commission finds that the cost of long-term debt should be 10.31 percent. The Commission further finds that, because short-term debt rates fluctuate continuously, the cost of short-

---

68 DeWard Prefiled Testimony, page 55.

69 Id.

term debt should be the average short-term rate for the test period of 10.03 percent.[70]

Return on Equity

Western recommended a return on equity ("ROE") in the range of 14.50 to 15.00 percent.[71] Western's recommendation was based on a discounted cash flow ("DCF") analysis for 15 gas distribution utilities, as well as comparative DCF analyses of electric utilities and unregulated companies. Western concluded that the average cost of common equity for gas distribution utilities is at least 13.50 percent based on a dividend yield of 7.08 percent and a dividend growth rate of 6.35 percent, and argued that special risk factors of Atmos and Western increase the required ROE by 1.0 to 1.5 percent.

The AG recommended an ROE in the range of 12.00 to 12.50 percent, based on a DCF analysis of five gas distribution utilities. The AG used four methods for developing the growth estimate for the DCF analysis: compound growth in dividends per share, compound growth in earnings per share, compound growth in book value per share, and the earnings retention ratio multiplied by the ROE. Each of the methods yielded substantially different results, ranging from the 2.92 percent growth estimate using earnings retention ratio times ROE, to the 5.95 percent growth estimate using dividends per share. The AG averaged these four

---

70 Id.

71 Testimony of Dr. Richard L. Wallace, page 54.

methods to arrive at a growth estimate in the range of 4.50 to 5.00 percent.

The Commission has traditionally used the DCF model in estimating ROE. Although one cannot rely on a strict interpretation of the DCF model, the Commission finds that the DCF approach based on dividend growth will provide the best estimate of an investor's expected ROE. The Commission finds that the historical, compound growth rate of 6.35 percent estimated by Western overstates the growth rate of dividends expected in the future. The Commission also finds that the evidence of record does not support an adjustment to Western's ROE of 1.0 to 1.5 percent for special risk factors. All companies have certain risk characteristics which differentiate them from other enterprises, and the evidence in this case is not persuasive that Western/Atmos's risk profile is so unique as to require an additional return beyond that allowed herein.

The Commission, having considered all of the evidence, including current economic conditions, finds that the cost of common equity is within a range of 12.0 to 13.0 percent. Within this range an ROE of 12.50 percent will best allow Western to attract capital at a reasonable cost, maintain its financial integrity to ensure continued service, provide for necessary expansion to meet future requirements, and also result in the lowest possible cost to ratepayers.

Rate of Return Summary

Applying rates of 10.31 percent for long-term debt, 10.03 percent for short-term debt, and 12.50 percent for common equity to the recommended capital structure approved herein produces an overall cost of capital of 11.20 percent. The Commission finds this overall cost of capital to be fair, just, and reasonable.

REVENUE REQUIREMENTS

Based upon the Commission's findings and determinations, Western requires an increase in revenues of $1,018,455, determined as follows:

Net Investment Rate Base	$63,401,818
Rate of Return	11.20%
Required Net Operating Income	7,101,004
Adjusted Net Operating Income	6,484,278
Deficiency	616,725
Tax Factor	.60555
Increase Required	$ 1,018,455

OTHER ISSUES

Cost-of-Service Study

Western presented a fully allocated embedded class cost-of-service study for the purpose of distributing revenue requirements among rate classes and determining rates of return on rate base at present and proposed rates for the following rate classes: Residential, Commercial, Firm Industrial (G-1 Industrial), Interruptible customers using less than 200,000 Mcf per year (G-2 Interruptible), and Interruptible customers using over 200,000 Mcf per year (G-3 Interruptible). Western stated that these rate classes follow its current rate design and differ from one another in key load characteristics, such as annual use per customer, seasonality of use, and load factor.[72] In

72 Prepared Testimony of Thomas H. Petersen, page 6.

distributing costs to rate classes, Western applied a three step allocation process, described by its witness in the following manner:

> First, costs were distributed among the functions of gas cost, storage, distribution, transmission and production. Second, the costs in each function were further classified by whether they were primarily related to the number of customers served, the amount of the commodity delivered, or the daily demands placed on the system. Finally, each functionalized and classified cost was allocated among customer classes.[73]

Western's cost-of-service study indicates that, at present rates, the Residential and Commercial classes have negative rates of return on rate base of (1.31 percent) and (0.71 percent), respectively. The G-1 Industrial class has a rate of return of 24.28 percent, while the rates of return for the G-2 and G-3 Interruptible classes are shown to be 33.6 percent and 37.24 percent, respectively. Overall system rate of return at present rates is 5.77 percent. At proposed rates, the differences between class rates of return are substantially reduced. Class rates of return at proposed rates are as follows: 12.02 percent for Residential, 9.3 percent for Commercial, 18.95 percent for G-1 Industrial, 17.26 percent for G-2 Interruptible, and 17.34 percent for G-3 Interruptible. Overall system rate of return at proposed rates is 12.5 percent.

---

73 Id., page 7.

Western stated that its present cost-of-service methodology differs from that filed in Case No. 9556[74] in two significant ways.[75] First, a zero-intercept method was used to classify distribution mains into customer and demand components instead of a minimum system method. Second, pipeline demand costs were allocated to interruptible and firm customers based on an average and peak demand method, instead of by class demands on design day with curtailment.

The Commission believes that the zero-intercept methodology is a more acceptable way to divide distribution main costs into demand-related and customer-related components than the minimum system method. Moreover, the Commission is convinced that the zero-intercept method, which utilizes regression analysis to determine the average unit cost of a theoretical zero diameter main, is statistically and theoretically sound and less subjective than the minimum system method, in which a "minimum" size main must arbitrarily be chosen in order to determine the customer-related component. The Commission, therefore, finds that this modification to Western's cost-of-service methodology is acceptable.

In Case No. 9556, the Commission recommended that Western include, in subsequent cost-of-service studies, alternative

---

74 Case No. 9556, Rate Adjustment of Western Kentucky Gas Company On Notice.

75 Prepared Testimony of Thomas H. Petersen, pages 8-9.

methods of cost allocation, such as the peak and average method.[76] This allocation methodology considers volume of use, in addition to peak demand, in determining class responsibility of certain demand-related costs. Use of this methodology by Western in its present cost-of-service study specifically addresses the Commission's concern, as expressed in Administrative Case No. 297[77], regarding cost-of-service methodologies that allocate costs based entirely on maximum design day. The Commission, in that proceeding, stated that cost-of-service methodologies should give some consideration to volume of use.[78] The Commission, therefore, finds that Western's allocation of pipeline demand charges based on an average and peak methodology is acceptable.

KIUC supports Western's cost-of-service study and its rate llocation implications.[79] KIUC's evidence underscored that the average and peak methodology is inappropriate for the allocation of Western's pipeline demand and transmission plant costs, because the method penalizes efficient consumption and encourages system under-utilization. Furthermore, according to KIUC, demand-related costs are unrelated to average demand.[80] KIUC recommends that the

---

76 Case No. 9556, Order dated October 31, 1986, page 32.

77 Administrative Case No. 297, An Investigation of the Impact of Federal Policy on Natural Gas to Kentucky Consumers and Suppliers, Order dated September 30, 1986, page 47.

78 Id.

79 Brief of KIUC, page 1.

80 Prefiled Testimony of Kenneth Eisdorfer, page 13.

Commission order Western to file a cost-of-service study in its next rate case that does not utilize the average and peak methodology for the allocation of transmission plant and demand-related purchased gas cost.[81] The Commission will not order Western to file a cost-of-service study which excludes an average and peak allocation methodology since, in fact, it was Commission directives in Administrative Case No. 297 and Case No. 9556 that prompted Western to utilize such a methodology in its present cost-of-service study. However, the Commission encourages all utility companies and intervenors to file well researched and documented alternative and multiple-methodology cost-of-service studies in all future rate proceedings. In Case No. 10201,[82] the Commission stated that a well documented and separated multiple-methodology approach to cost-of-service studies will provide it additional information for rate design. The Commission continues to believe that such an approach to cost-of-service studies is appropriate and beneficial.

Southwire contends that Western's cost-of-service study is biased toward overstating the cost of serving industrial and interruptible classes of customers.[83] In the opinion of

---

81 Brief of KIUC, page 13.

82 Case No. 10201, An Adjustment of Rates of Columbia Gas of Kentucky, Inc., Order dated October 21, 1988, page 54.

83 Brief of Southwire, page 4.

Southwire, this bias is introduced into Western's cost-of-service study by the zero-intercept estimation which allocated more of the costs of distribution mains to the industrial classes than would a minimum system method.[84] Notwithstanding those arguments, Southwire stated that Western's study, being the only cost-of-service study presented, resulted in a fair, just, and reasonable rate design.[85]

Like Southwire, Logan asserts that Western's use of a zero-intercept methodology in its cost-of-service study, instead of the minimum system method, biased the results of the study in favor of the residential class of customers.[86] Nevertheless, Logan believes that Western's study accurately and appropriately functionalizes, classifies, and allocates Western's costs among the rate classes it serves.[87]

The AG contends that Western's cost-of-service study is flawed since Western incorrectly allocated a portion of storage plant costs based on peak demand allocators instead of a volume-based allocator.[88] The AG asserts that, since Western's

---

84 Id.

85 Id., page 5.

86 Brief of Logan, pages 8-9.

87 Id., page 10.

88 Prefiled Testimony of Michael F. Sheehan, page 25.

storage plant is used for "financial purposes" and not for peaking purposes, allocation should have been based on volume.[89] Similarly, KLS criticizes Western's cost-of-service study because it did not allocate pipeline demand charges based entirely on annual volumes.[90]

Western has presented the only complete cost-of-service study in this proceeding. Whereas all intervenors are critical of certain elements of Western's study, only the AG and KLS found it unacceptable as a guide in the design of rates in this case. None of the intervenors, however, presented alternative studies supporting their views. Based on its review of the record pertaining to Western's cost-of-service study, the Commission finds that Western's study is responsive to its concerns as expressed in Administrative Case No. 297 and Case No. 9556 and is reasonable and acceptable as a starting point for rate design.

Revenue Allocation

Western's revenue allocation proposal consists of two parts: (1) a reallocation of pipeline demand charges between firm and interruptible customers, and (2) a shift in the recovery of non-gas costs from interruptible to firm customers. Western based its revenue allocation on its class cost-of-service study as previously discussed.

The allocation of pipeline demand charges as proposed by Western would shift approximately $2.2 million in costs from

---

89 Brief of the AG, page 40.

90 Brief of KLS, page 5.

interruptible customers to firm customers. Western's proposal is based on an average and peak demand allocator, which recognizes the relationship between average (annual) volumes of 41.6 million Mcf and annualized peak (design day) volumes of 98.5 million Mcf. The resulting ratio of 42.2 percent is multiplied by Western's pipeline demand charges to arrive at the portion of demand charges to be spread over all volumes. The remaining 57.8 percent of pipeline demand charges would be spread over Western's firm volumes of 26.1 million Mcf.

Of its requested increase in base rate revenues of approximately $9 million, Western proposed increases of $9.5 million for firm service customers and decreases of $.5 million for interruptible customers. This proposal reflected Western's cost-of-service study and gave recognition to competition from other fuels and the economic risks of bypass by industrial customers. The proposed allocation produced increases of 17.2 percent for residential customers and 11 percent for commercial customers with a 15.7 percent decrease for industrial customers.

KIUC, Southwire, and Logan generally supported Western's proposed revenue allocation as an appropriate step in the direction of cost-based rates, although all the industrial intervenors recommended a greater reduction in industrial rates than the reduction proposed by Western. KIUC cited biases in Western's cost-of-service study that it claimed tend to overstate the level of costs allocated to the industrial rate classes.[91]

---

91 Prepared Testimony of Kenneth Eisdorfer, pages 12-17.

The AG and KLS both argued that Western's cost-of-service study was flawed and that Western's rate proposals for industrial customers reflect competitive pricing rather than cost-of-service pricing. The AG argued that the industrial class, with its demonstrated ability to use alternate fuels and/or bypass Western, poses a greater risk to Western than its other customers and that such risk should be reflected in Western's cost allocation and rate design.[92]

In one fashion or another, Western and the intervenors recognize the concept of rates based on fully allocated costs. However, beyond such recognition, there is little agreement as to the proper determination of fully allocated costs and how such costs should be reflected in the allocation of Western's revenues. The Commission is aware that various criticisms have been directed at Western's cost-of-service study as the basis for designing rates; however, the study was responsive to the Commission's Orders in Western's last rate case, Case No. 9556 and Administrative Case No. 297. It is with the directives of those Orders in mind that the Commission has evaluated Western's revenue allocation.

In making its evaluation the Commission recognizes that the natural gas industry has undergone major changes in recent years. Those changes began with federal legislation in the late 1970s which provided for the removal of many of the controls on the

---

92 Prepared Testimony of Michael F. Sheehan, pages 13-17.

wellhead price of gas. Those changes have continued through the 1980s with federal regulatory decisions that permit end-users to arrange for their own gas supplies and use the local distribution company ("LDC") as a transporter of those supplies. Federal regulatory decisions have also permitted end-users to bypass the LDC and take service directly from a pipeline supplier.

As a result of these actions, large volume end-users, mainly industrial customers, have sought out their own gas supplies at prices less than the LDC's price for its system supply gas. These industrial customers have also argued that absent cost-based transportation rates from the LDCs, those customers will bypass with the result being loss of load and loss of revenues for the LDC.

These circumstances represent a significant departure from the time when all customers were essentially captive and there was little incentive for companies or regulators to consider costs as a major factor in allocating revenues and designing rates. The results of regulation in this "pre-cost" era were that services were often priced at less than the cost of service to residential customers and priced at more than the cost of service to commercial and industrial customers. Conventional wisdom held that because commercial and industrial customers could pass along price increases to their customers it was more palatable to over-price services to those customers while under-pricing services to residential customers.

It is these past circumstances and practices that have contributed to the allocation and rate issues presented in this case. The Commission recognizes these to be serious issues which require reasoned and deliberate analysis that considers the conditions existing in today's competitive environment as well as the rate impact on Western's captive customers. While recognizing that its decision may not be popular with those captive customers, the Commission believes that a restructuring of Western's rates is necessary as explained in the following paragraphs.

The most significant aspect of Western's rate restructuring is its proposed allocation of pipeline demand charges for recovery through its gas cost adjustment clause. The Commission finds that the average and peak allocator utilized by Western reflects both average volumes and design day volumes in the allocation of costs and recognizes the differing characteristics of firm and interruptible loads. It addresses the Commission's concern, expressed in Administrative Case No. 297 that companies consider the possible de-averaging of the costs of gas and how to assign those costs by customer class. Furthermore, it is responsive to the Commission's Order in Case No. 9556 which specifically recommended that Western evaluate alternative methods of cost allocation such as the average and peak method. Therefore, the Commission concludes that Western's proposed allocation of pipeline demand charges is reasonable and equitable and should be approved. The Commission also finds that the allocation of pipeline demand charges should be updated annually as part of Western's first gas cost adjustment filing following the development of its design day plan.

The second part of Western's rate restructuring involves the allocation of non-gas, or base rate revenues. The Commission finds that the firm customer classes, at present rates, are not making an adequate contribution to Western's overall rate of return and that, in order to increase that contribution, the full amount of the increase granted herein should be allocated to those customer classes.

The Commission also finds that none of the increase granted herein should be allocated to Western's interruptible classes but rather that the base rate revenue contribution of the interruptible classes should remain unchanged. The Commission concurs with the AG that Western's interruptible customers, with their non-captive status, impose a greater level of risk on Western than do its firm, essentially captive customers. The Commission finds that such risk translates into higher rates of return, which Western attempted to reflect in its cost-of-service study. The Commission has previously made similar findings regarding the risks associated with serving non-captive industrial customers in Case No. 10498.[93]

The Commission finds that maintaining the test-year base rate revenue contribution for the interruptible rate classes recognizes the greater risks attendant with serving these classes and follows the moderate, gradual course of action for rate restructuring

---

93 Case No. 10498, Adjustment of Rates of Columbia Gas of Kentucky, Inc., Order dated October 6, 1989, pages 48-49.

outlined by the Commission in Administrative Case No. 297.[94] As this is Western's first rate case since Administrative Case No. 297, the Commission, contrary to KIUC's arguments, concludes that gradualism should be recognized in the allocation of revenues. While Western contends that gradualism was considered in preparing its case, the requested increases and the proposed class rates of return reflect major revenue shifts with little regard to gradualism or rate continuity.

Maintaining the same interruptible revenue levels while pricing some of its contract volumes at tariffed rates will have the impact of reducing Western's interruptible rates. In conjunction with the reallocation of pipeline demand charges, this approach results in a significant restructuring of Western's rates.

Rate Design

Western proposed to double the customer charges for residential and non-residential firm customers to $6 and $16, respectively, and, for the first time, to impose a customer charge on interruptible customers. The interruptible customer charge would match the $16 charge for non-residential firm customers. Western proposed to combine Interruptible Rate Schedules G-2 and G-3 and to change from a flat rate to a declining block rate structure for all rate schedules. For firm customers on Rate Schedule G-1, the first block of 300 Mcf would be priced 62.6

---

94 Order dated September 30, 1986, page 40.

cents above the second block of 14,700 Mcf, which in turn, would be priced 20 cents above the last block for sales above 15,000 Mcf. For interruptible customers on the combined Schedule G-2, the first block of 15,000 Mcf would be priced 20 cents above the second and, last, block for everything over 15,000 Mcf. Western indicated that the 15,000 Mcf break point and related 20 cents rate differential were based on its cost-of-service study with the intent of making the firm and interruptible schedules more compatible. Western also indicated that the first block of 300 Mcf on the G-1 Schedule was designed to capture all residential and most small commercial volumes at the higher rate in order to improve the rates of return for the residential and commercial classes.

The AG contends that the G-1 rate design proposed by Western for firm customers discourages conservation and places a disproportionate share of fixed cost recovery on low volume customers. The AG recommended a rate design with a smaller customer charge and a flat block, or flatter, declining block rate structure for firm volume customers.

The AG recommended that for interruptible customers Western should recover a much larger portion of fixed costs through the customer charge and first block than had been proposed. The AG maintains that such an approach would make fixed cost recovery less uncertain and would be consistent with Western's rate proposals for firm service customers.

The proposal to combine schedules G-2 and G-3 with one resulting G-2 rate schedule for interruptible customers equitably reflects Western's cost of service and is acceptable. The Commission finds Western's objective in proposing a declining block rate structure is supported by the cost-of-service study and the proposed rate blocks for G-1 and G-2 appear to be reasonable; however, in consideration of the concerns expressed by the AG and in keeping with its goals of moderation, gradualism, and rate continuity, the Commission will set rates that reflect only a 15-cent differential between blocks. Western's proposed customer charges for firm customers have also been rolled back to $3.50 and $9.35 based on the amount of the increase granted herein.

Western proposed a customer charge for interruptible customers and set it at the $16 level proposed for firm non-residential customers. The $16 charge was proposed even though Western's calculation of its G-2/G-3 monthly customer costs ranged from $344 to $1,544. The AG's evidence argues for a larger, up-front charge as a means of recovering a larger proportion of fixed costs from these customers.[95] The Commission finds that a larger fixed charge would better reflect Western's cost of service and would result in reduced reliance on sales volumes for the recovery of fixed costs. Therefore, the Commission finds a monthly customer charge or base charge of $100 per delivery point for rates G-2 and T-3 to be reasonable as another component in the restructuring of Western's rates to better reflect its cost of service. Customers that take both firm

---

95 Prepared Testimony of Michael F. Sheehan, page 16.

volumes and interruptible volumes should be billed as interruptible customers for purposes of determining the customer charge.

The rates set out in the Appendix will produce the additional revenues granted herein. The rate changes, by customer class, produce increases of 6.2 percent and 5.2 percent, respectively, for residential and commercial customers, and a decrease of 8.0 percent for industrial customers. These percentage changes do not reflect the decrease in Western's commodity gas costs since the filing of this case.

<u>Carriage Service</u>

In compliance with the Commission's Order in Administrative Case No. 297, Western proposed a carriage (transportation) rate which excludes standby service. The proposed transportation rate, Rate T-3, recovers Western's simple margin applicable to interruptible service and includes those non-commodity gas costs related to take-or-pay recovery.

KIUC maintains that Rate T-3 should not be based on Western's simple margin as it includes costs related to gas stored underground and production plant. Western's proposal, which is similar to the carriage and transportation rates the Commission has approved for other companies, recognizes that establishing a smaller margin for carriage service could negatively impact earnings if substantial loads switched from Western's existing transportation service to carriage service.

Western's proposal to base its carriage rate on its simple margin applicable to interruptible service is reasonable and sound from both a rate-making and economic perspective. The Commission, therefore, accepts this proposal and authorizes Western to provide carriage service based on the simple margin established in this case.

Energy Assurance Program

KLS proposed that Western implement an energy assurance program ("EAP") to assist low-income customers in paying their gas bills and to improve Western's ability to collect from those customers.[96] KLS contends that Western's traditional collection mechanisms are not producing the maximum revenue stream possible from low-income customers which, in turn, results in additional costs being born by all ratepayers.

Under the EAP, households living at or below 150 percent of the federal poverty level with an annual energy bill that exceeds 6 percent of the household's income would make payments toward its current bill equal to 6 percent of its monthly income. Each household would be required to also make a monthly payment of $3 for 36 months toward reducing its existing arrearages; Western would be required to write-off any arrearages in excess of the total of $108 paid by the participant household. These households would also be targeted for education and energy conservation programs to encourage reduced energy use.

KLS estimated that Western could implement this program at virtually no cost and increase the revenues collected from its

96 Prepared Testimony of Roger D. Colton, pages 9-15.

low-income customers. It is KLS' opinion that the provisions of the EAP do not conflict with either the statutes or the administrative regulations governing utility regulation in the Commonwealth of Kentucky.[97] KLS also stated that the EAP represents a collection issue and not a rate issue.[98]

The Commission has concerns about the accuracy of the predicted costs and cost savings of the EAP and questions whether such a program should be imposed on a company absent a detailed company-specific analysis. More importantly, contrary to the opinion of KLS, the Commission considers some aspects of the EAP to represent a rate issue which does not comport with Kentucky statutes 278.160 and 278.170. These statutes prohibit a utility from (1) giving any unreasonable rate preference or advantage to any customer and (2) charging or receiving any less compensation that what is prescribed in its filed rate schedules. Under the EAP, Western would be charging less than the amount prescribed in its rate schedules and would, particularly in instances where the fixed payment based on a percentage of income would not recover variable costs, be giving an unreasonable preference to these customers. Therefore, the Commission finds that the EAP proposed by KLS cannot be imposed on Western as such program does not comply with Kentucky statutes.

---

97 T.E., Vol. III, pages 73 and 74.

98 Id., pages 52-53.

In addition to the statutory prohibition, the Commission is concerned about the degree to which the EAP would place a utility in the position of administering a social program. While the Commission recognizes that a number of customers in the low-income category have difficulty paying their utility bills, the notion of a Commission-approved subsidy program is not the answer. The Commission believes that government-sponsored programs such as LIHEAP should be utilized to the fullest extent possible, with the emphasis on government-sponsored programs, as opposed to utility/ratepayer-sponsored programs.

Standard Contract Form

As part of its application Western submitted a proposed service agreement with the heading "Large Volume Natural Gas Service Contract." Western's legal counsel stated that it was Western's intent that the standard contract form be approved to be filed as part of its tariffs. Western indicated that, with Commission approval of the standard contract form, it would intend that the general terms and conditions set forth in the contract would be applicable to all new contract customers and that the standard contract would be offered to those customers for their acceptance.

The Commission is concerned that a standard contract form might be too restrictive for some circumstances and could limit the flexibility of both Western and its customers. While the general terms and conditions appear to be reasonable, the Commission would prefer to review separately the merits of each individual contract, thereby giving all parties, including the

Commission, greater latitude in the area of customer service contracts. Therefore, the proposed standard contract form will not be approved to be included as part of Western's tariffs.

Tariff Changes

Western's proposed tariffs reflected its changes in rate design, the combining of rates G-2 and G-3, the proposed carriage service, and the changes in its gas cost adjustment clause resulting from its proposed allocation of pipeline demand charges. In addition, Western proposed several minor text changes in its tariffs which have not specifically been addressed herein. The major tariff changes or additions as approved by the Commission are shown in the Appendix to this Order. Any minor text changes not specifically shown in the Appendix are approved as proposed by Western.

SUMMARY

After consideration of all matters of record, the evidence, and being otherwise sufficiently advised, the Commission finds the following:

1. The rates in the Appendix, which is attached hereto and incorporated herein, are the fair, just, and reasonable rates for Western to charge its customers for service rendered on and after the date of this Order.

2. The rates proposed by Western would produce revenue in excess of that found reasonable herein and should be denied.

3. The rate of return granted herein is fair, just, and reasonable and will provide for the financial obligations of Western with a reasonable amount remaining for equity growth.

4. The tariff changes set forth in the Appendix are reasonable and should be approved.

IT IS THEREFORE ORDERED that:

1. The rates in the Appendix are approved for services rendered by Western on and after the date of this Order.

2. The rates proposed by Western are hereby denied.

3. The text changes authorized herein and the tariffs set forth in the Appendix are hereby approved.

4. Within 30 days of the date of this Order, Western shall file with the Commission revised tariffs sheets setting out the rates and tariff provisions approved herein.

Done at Frankfort, Kentucky, this 13th day of September, 1990.

By the Commission

ATTEST:

Lee M Macdracken

Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 90-013 DATED 9/13/90

The following rates and charges are prescribed for the customers in the area served by Western Kentucky Gas Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order. These rates reflect all gas cost adjustments through Case No. 9556-O.

GENERAL SALES SERVICE RATE G-1

Rate - Net:

Base Charge:	$3.50	per meter per month for residential service
	$9.35	per meter per month for non-residential service

Commodity Charge:

First 300 Mcf per month	$4.3435	per 1,000 cubic feet
Next 14,700 Mcf per month	$4.1935	per 1,000 cubic feet
Over 15,000 Mcf per month	$4.0435	per 1,000 cubic feet

All gas consumed by the customer (sales, transportation, firm and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

INTERRUPTIBLE SALES SERVICE RATE G-2

Rate - Net:

Base Charge:	$100.00	per delivery point per month

Interruptible Service:

Gas used per month in excess of the high priority service shall be billed as follows:

First 15,000 Mcf per month	$3.6546	per 1,000 cubic feet
All over 15,000 Mcf per month	$3.5046	per 1,000 cubic feet

All gas consumed by the customer (sales, transportation, firm and interruptible) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.

GENERAL TRANSPORTATION TARIFF RATE T-2

Rate:

In addition to any and all charges assessed by other parties, there will be applied a Gross Margin Transportation Rate which shall be:

A. The Simple Margin as being the difference between the otherwise applicable Sales Tariff Rate and the Base Cost of Gas (BCOG), fixed at $3.4344, for firm service and $3.1771 for interruptible service as approved by the Company's most recent rate Order, Case No. 90-013, plus

B. The Non-Commodity Components as calculated in the Company's most recent Quarterly Gas Cost Adjustment (GCA) filing.

Special Provisions:

A. Service under this rate schedule entitles the customer to purchase sales gas from the Company at the applicable tariff rates when its supply requirements exceed the nominated volume. The customer is entitled to purchase natural gas from the Company consistent with the applicable Sales Rate Schedule.

CARRIAGE SERVICE TARIFF RATE T-3

Applicable:

Entire service area of the Company to any customer for that portion of the customer's interruptible requirements not included under one of the Company's sales tariffs.

Availability of Service:

A. Available to any customer with a daily nominated volume (see Definition, Section 4) which averages a minimum of 100 Mcf of gas per day for the billing period on an individual service at the same premise which has purchased its own supply of natural gas and requires carriage by the Company to the point of utilization, subject to suitable service being available from existing facilities. (See Section 7 if additional facilities are necessary.)

B. The Company may decline to initiate service to a customer under this tariff or to allow a customer receiving service under this tariff to elect any other service provided by the Company, if in the Company's sole judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

Rate:

Monthly Base Charge: $100.00 per delivery point

Minimum Charge: The Base Charge

In addition to any and all charges assessed by other parties, there will be applied a Carriage Service Commodity Rate consisting of:

A. The Simple Margin applicable to interruptible service, as approved in the Company's most recent rate Order, Case No. 90-013, plus

B. Any applicable non-commodity components as approved in the Company's most recent Gas Cost Adjustment (GCA) filing.

Carriage Service Commodity Rates are stated at PSC No. 19, Sheet No. 17.

Nominated Volume:

Definition: "Nominated Volume" or "Nomination" - The level of daily usage in MMbtu (to be converted to Mcf for billing purposes) as requested by the customer to be carried by the Company.

Such nomination request (nomination form plus required offers of credit and/or waivers or any other data required) shall be made by the customer or its agent to the Company on a monthly basis a minimum of ten (10) working days prior to commencement of the billing period. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

Curtailment:

A. The Company shall have the right at any time, without liability to the customer, to curtail or to discontinue the delivery of gas entirely to the customer for any period of time when such curtailment or discontinuance is necessary to protect the requirements of domestic and commercial customers; to avoid an increased maximum daily demand in the Company's gas purchases; to avoid excessive peak load and demands upon the gas transmission or distribution system; to relieve system capacity constraints; to comply with any restriction or curtailment of any governmental agency having jurisdiction over the Company or its supplier or to comply with any restriction or curtailment as may be imposed by the Company's supplier; to protect and insure the operation of the Company's underground storage system; for any causes due to force majeure (which includes acts of God; strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

B. All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 29 of its Rules and Regulations as filed with and approved by the Public Service Commission.

Measurement:

The unit of measurement shall be a Mcf at a pressure base of 14.65 psia, a temperature of 60 degrees Fahrenheit and 0.60 specific gravity.

Special Provisions:

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which may be required as a result of receiving service under this Carriage Service Rate T-3.

A written contract with maximum daily and monthly carriage volumes and with a minimum term of one year shall be required.

No gas delivered under this rate schedule and applicable contract shall be available for resale.

Terms and Conditions:

A. Specific details relating to volume, delivery point/meter number and similar matters shall be covered by a separate written contract or amendment with the customer.

B. The Company will not be obligated to deliver a total supply of gas to the customer in excess of the customer's maximum daily carriage volumes. The Company has no obligation under this tariff to provide any sales gas to the customers.

C. It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas under this Carriage Service Rate to the facilities of the Company.

D. The Company reserves the right to refuse to accept gas that does not meet the Company's quality specifications.

E. The Rules and Regulations and Orders of the Kentucky Public Service Commission and of the Company and the Company's General Terms and Conditions applicable to the Company's Sales Tariff Rates shall likewise apply to these Carriage Service Rates and all contracts and amendments thereunder.

F. The customer must provide the Company a minimum 24 hour advance notice of any change in the status of the customer's gas supply or gas usage during the month. In the event the customer loses its gas supply, it will be allowed two working days in which to secure replacement volumes (up to the maximum daily carriage quantity) and resubmit its nomination to the Company. This volume will be subject to the provisions of Section G if not made up by the end of the month.

G. Volumes taken by the customer in excess of carriage volumes available for delivery by the Company in a month shall be deemed as overrun and will be billed at $10.00 per Mcf.

H. In the event a customer fails in part or in whole to comply with a Company curtailment order either as to time or volume of gas used or uses a greater quantity of gas than its daily carriage demand or a quantity in excess of any temporary authorization whether a curtailment order is in effect or not, the customer shall pay for the unauthorized gas so used at the rate of $15.00 per Mcf. Billing of this penalty shall be made within 90 days of the date of violation and shall be due and payable within 20 days of billing.

The payment of penalty charges shall not be considered as giving any customer the right to take unauthorized volumes of gas nor shall such penalty charges be considered as a substitute for any other remedy available to the Company.

I. The customer will be solely responsible to correct, or cause to be corrected, any imbalances it has caused on the applicable pipeline's system.

Late Payment Charge:

Should any customer fail to pay all of the amount of any bill within ten (10) days after such bill is rendered, interest on the unpaid portion of the bill shall accrue, at the then effective prime interest rate (Citizens Fidelity Bank and Trust Company, Louisville, Kentucky) from the due date, until the date of payment.

TRANSPORTATION RATE T-2 AND CARRIAGE RATE T-3

The General Transportation Tariff Rate T-2 and Carriage Service Rate T-3 for each respective service rate is as follows:

Transportation Service Rate T-2

Includes standby sales service under corresponding sales rates.

General Service Rate G-1:

	Simple Margin	+	Non-Commodity Components	=	Gross Margin Transportation Rate Per 1,000 Cu. Ft.
First 300 Mcf/mo.	$0.9091		0.4151		$1.3242
Next 14,700 Mcf/mo.	0.7591		0.4151		1.1742
All over 15,000 Mcf/mo.	0.6091		0.4151		1.0242

Interruptible Service Rate G-2:

	Simple Margin	+	Non-Commodity Components	=	Gross Margin Transportation Rate Per 1,000 Cu. Ft.
First 15,000 Mcf/mo.	$0.4775		0.1573		$0.6348
All over 15,000 Mcf/mo.	0.3275		0.1573		0.4848

Carriage Service Rate T-3:

Excludes standby sales service.

	Simple Margin	+	Non-Commodity Components	=	Gross Margin Transportation Rate Per 1,000 Cu. Ft.
First 15,000 Mcf/mo.	$0.4775		0.0358		$0.5133
All over 15,000 Mcf/mo.	0.3275		0.0358		0.3633

GAS COST ADJUSTMENT CLAUSE

BCOG is the base cost of gas per 1,00 cubic feet:

Firm Service (Rate G-1)	$3.4344 per 1,000 cubic feet
Interruptible Service (Rate G-2)	$3.1771 per 1,000 cubic feet

Applicable to: All Service Rate Schedules

	Firm	Interruptible
Gas Cost Adjustment (GCA) per 1,000 cubic feet	$(0.5919)	$(0.5924)
Refund Adjustment (RF) per 1,000 cubic feet	0.0000	0.0000
Net GCA Factor per 1,000 cubic feet	(0.5919)	(0.5924)

Derivation of above adjustments:

Gas Cost Adjustment (GCA)	Firm	Interruptible
Expected Gas Cost Component (EGC)	$ 2.9763	$ 2.7185
Less: Base Cost of Gas (BCOG)	3.4344	3.1771
Gas Cost Component (EGC minus BCOG)	(0.4581)	(0.4586)
Gas Cost Actual Adjustment (GCAA)	(0.0443)	(0.0443)
Gas Cost Balance Adjustment (GCBA)	(0.0895)	(0.0895)
Sub-Total	$(0.5919)	$(0.5924)

Refund Adjustment (RF)

Refund factors continuing for 12 months from the effective date of each refund filing:

Refund effective 5/1/89 Case No. 9556-J	\$(0.0000)	\$(0.0000)
Total Refund Factor (RF)	(0.0000)	(0.0000)
Net GCA Factor per 1,000 feet	\$(0.5919)	\$(0.5924)

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 185
Witness: Bernard Uffelman

Data Request:

Are firm carriage services included in the same classes as interruptible services? If so, why?

Response:

For purposes of the CCOS study, firm carriage customers are included in the same rate class as interruptible service customers. To the extent that a carriage customer delivers and transports its gas on the Atmos Energy Corporation Kentucky Division's system, such gas will be delivered and the service is considered a firm service. However, Atmos Energy Corporation Kentucky Division has no obligation to provide gas supply to a customer electing service under the firm carriage service tariff. Any overrun volumes may be billed at a penalty rate up to $15 per Mcf.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 186
Witness: Bernard Uffelman

Data Request:

At page 12, lines 9 through 11, Mr. Uffelman states that interruptible and carriage service may be curtailed under peak load conditions. Does this statement apply to Rate T-4, Firm Carriage Service? If so, please explain why this service is characterized as "firm."

Response:

Rate T-4 firm carriage service customers are subject to gas supply curtailment in accordance with Atmos Energy Corporation Kentucky Division's T-4 rate tariff (Item No. 7). Firm Carriage service is considered a firm service as explained in the response to Attorney General's Initial Data Request, Question No. 185.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 187
Witness: Gary Smith

Data Request:

For the most recent winter season, please identify:

a. The number of interruptions to interruptible customers,
b. The duration of each interruption,
c. The number and load of interruptible customers who actually curtailed their service during each interruption,
d. The number and load of interruptible customers who failed to curtail their service during each interruption.
e. For purposes of this request, include both interruptible sales and interruptible carriage service as "interruptible."

Response:

For purposes of orientation, "interruptions" in today's environment are somewhat different than those of ten years ago. The vast majority of Atmos Energy's "interruptible" customers are those utilizing carriage transportation services (T-3 and T-4 tariffs). Carriage customers are transportation-only customers who forego their rights to the Company's gas supply, which is dedicated to sales customers and transporters with standby sales service (T-2 tariff). Under normal circumstances, modest daily imbalances by carriage customers pose no challenge to the Company's management of gas supply for sales customers. However, during critical periods, the Company will "curtail" carriage customer access to any overrun gas supply. These "curtailment" notices advise customers that they must deliver adequate daily transportation supply to cover their requirements in order to avoid the risk of potential penalties. Typically, if adjustments are necessary by the carriage customers, they supplement their nominated gas supply instead of reducing their gas usage.

Often, the Company will "curtail" only down to Priority 7 (imbalance sales to carriage customers) of its Curtailment Order (reference Sheet 95 of the Company's tariffs), which does not apply to the Company's few remaining interruptible sales customers.

During this most recent winter season (2006-2007), no curtailment notices have been issued by the Company. This is due to the relatively mild winter temperatures experienced this winter and the overall balancing performance of our transportation customers and their marketers/suppliers.

In the previous two winter seasons (2004-2005 and 2005-2006) Curtailment Orders were issued on a number of occasions, and compliance with the Orders by customers and their suppliers has been very favorable.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 188
Witness: Gary Smith

Data Request:

Would the Company support or oppose separating gas costs from non-gas costs, with all of the former recovered through a Purchased Gas Charge and the latter through customer and energy Distribution Charges?

Response:

The Company supports, and currently employs, the referenced methodology. Please reference response to AG DR 1-178 for a listing of cost categories by account subject to the Gas Cost Adjustment.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 189
Witness: Gary Smith

Data Request:

Please identify the proportion of gas costs recovered in base rates and the proportion recovered in the Gas Cost Adjustment during the four quarters of the base period.

Response:

0% of gas costs are recovered in base rates, 100% of gas costs are recovered through the GCA.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 190
Witness: Bernard Uffelman

Data Request:

Refer to page 2 of the CCOS study. Please confirm that "Winter Season as a % of Annual Use" should be "winter peak use as % of annual use." If so, please define the peak use period that is used for the percentages in line 2. If not, explain the very low percentages shown for the interruptible classes.

Response:

The "Winter Season as a % of Annual Use" language referenced on page 2 line 2 of the class cost of service (CCOS) study is correct as stated in the CCOS study. As the wording indicates, the percentages referenced on line 2 represents the amount of gas consumed during the winter season (i.e., November 2005 through March 2006) as a percentage of the total annual gas used during the 12 month period ended August 31, 2006 for each customer class. The gas volumes used to compute these percentages are shown on page 14 lines 2 and 14 of the CCOS study. The low percentages for the interruptible and carriage customers simply indicate that such customers do not consume significantly larger amounts of gas during the winter period than they do during the remaining months of the annual period ended August 31, 2006, as compared to the residential, commercial and industrial customer classes. This appears reasonable given the differences in usage patterns between the residential, commercial, industrial, and interruptible and carriage class customers.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 191
Witness: Tom Petersen

Data Request:

Why is gas stored underground considered a rate base item rather than a gas cost item? Provide any Commission order(s) that support this treatment?

Response:

The company's investment of capital in gas stored underground is an investment that provides utility service to customers. Gas stored underground was included in rate base in the Commission's final decision in Case 90-013, the last general Atmos rate case that was not settled. The final order in 90-013 is provided in response to AG DR 1-184. The company has not researched other utility cases in Kentucky with regard to this item.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 192
Witness: Bernard Uffelman

Data Request:

Reference footnote 1, page 3 of the CCOS. Why are prepayments allocated on the basis of gross plant?

Response:

Prepayments were allocated on the basis of gross plant consistent with the methodology used to allocate prepayments in the Atmos Energy Corporation Kentucky Division's prior Kentucky rate proceeding, Docket 99-070.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 193
Witness: Bernard Uffelman

Data Request:

Reference page 5 of the CCOS: Do industrial, carriage and interruptible customers use services included in Account 380? If so, why are no service costs allocated to them?

Response:

The Atmos Energy Corporation Kentucky Division is not aware of any service investment associated with industrial, carriage or interruptible customers that was recorded to Account 380, therefore no investment costs were allocated to these customers. To the extent that such customers may have unidentified service investment recorded to Account 380, such investment would be minimal.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 194
Witness: Gary Smith

Data Request:

Reference page 16 of the CCOS: In light of the fact that almost no gas is sold in the rate block over 15,000 Mcf, would the Company object to eliminating this block? If the Company would object, please explain fully.

Response:

Although only 400 Mcf was sold in the greater than 15,000 Mcf per month block during the 12-months ending August 31, 2006, the report indicates 2,604,321 Mcf was transported in that corresponding greater than 15,000 Mcf per month block. With the large total volume within this rate block, the Company would not support elimination of the greater than 15,000 Mcf per month block.

In regard to eliminating the rate block for sales services only, the Company would not support the financial bias introduced by such an action.

One of the merits of the Company's rate structures is margin neutrality between sales and transportation services. With this fact, Atmos Energy can consult with customers qualifying for service options without financial bias to the customer's selection. Eliminating the rate block from sales service would serve little purpose and would have set the unintended precedent of introducing a financial bias for the Company between sales and transportation services.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 195
Witness: Gary Smith

Data Request:

Please refer to page 8 of Mr. Smith's testimony. Are the costs of the East Diamond storage field and contract interstate pipeline storage subject to the Gas Cost Adjustment, or are they in base rates?

Response:

The costs associated with the East Diamond storage field and contract interstate pipeline storage are recovered through the Gas Cost Adjustment.

Additionally, however, the traditional regulatory treatment of gas storage inventory costs recognizes the 13-month average balance as a rate base component. Refer also to the Company's response to AG DR 1-191.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 196
Witness: Greg Waller

Data Request:

How are the costs of Atmos's centralized gas purchasing services recovered? What was the amount of those costs during the historical base period and what are they expected to be in the forecast period?

Response:

Atmos's centralized gas purchasing function ("Gas Supply Services") is recovered, as of January 1, 2007, (see Waller testimony p. 15 lines 15-21 for discussion) as a component of Atmos' Shared Services Unit which is allocated to Kentucky per the allocation methodology described in the testimony of Mr. Cagle. Gas Control Services have and continue to be recovered as a component of SSU. The costs are outlined below:

	Base Period	Forecast Period
Gas Supply Services	$245,000	$249,598
Gas Control Services	$196,777	$193,055

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 197
Witness: Tom Petersen

Data Request:

Please provide the historical record of design day gas usage per customer by class of customer for the last five fiscal years, the current year and the forecast year.

Response:

The company does not measure peak day usage by customer class. The peak day usage in Mcf for firm gas sales for the past four winters is:

2002-2003	258,523
2003-2004	219,982
2004-2005	205,856
2005-2006	185,984

Peak day usage for the winter of 2001-2002 is not readily available.

The company does not regularly prepare design day forecasts by class of customer. The company does prepare design day forecasts for gas sales requirements. The current design day forecast is 261,416 Mcf or 268,831 Dth. Mr. Uffelman's class cost of service study contains the results of the current design day forecast as allocated among customer classes.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 198
Witness: Gary Smith

Data Request:

Please provide the calculation of the Margin Loss Recovery Rider for the most recent three fiscal years and, if available, for the forecast year.

Response:

For the past three years, in fact, since its inception in 1999, there have no Margin Losses subject to the referenced tariff rider. No Margin Loss Recoveries were included in the forecasted test year.

Atmos Energy Corporation, Kentucky
Case No. 2006-00464
Attorney General Initial Data Request Dated February 20, 2007
DR Item 199
Witness: Gary Smith

Data Request:

Please provide the calculation of the Weather Normalization Adjustment Riders for each month since the inception of the rider.

Response:

The Weather Normalization Adjustment (WNA) rider was first approved in Case 99-070, for a five year period beginning with the winter of 2000-2001. A five-year extension of the WNA rider was approved in KPSC Case No. 2006-00268. The formula for the WNA calculation has not changed to date, and is found on Sheet No. 22 of the Company's approved tariffs. The basis for normal weather remains as originally approved; the 30-year National Oceanic and Atmospheric Administration's (NOAA) published normal heating degree days for the period of 1961-1990. The only variables that are changed each year entering into the winter are the HSF, BL and R factors for each class of G-1 firm sales subject to WNA, residential, commercial and public authority. The workpapers showing this calculation for the winter of 2006-2007 are provided in the Company's response to AG DR 1-179. The billing system applies these factors in the calculation of the WNA including the normal heating degree days and actual heating degree days for each customer's billing period.

For each winter since inception, the attachments (Attachment AG DR 1-199, Sheets 1-6) summarize the applicable HSF, BL and R factors, and HDDs, along with the corresponding WNA revenues for each customer class by month.

Atmos Energy Corporation (KY Division)
WNA Summary Report
2000-2001 Heating Season
November - April

		2000-2001 Heating Season						
		November	December	January	February	March	April	Total
RESIDENTIAL								
R Factor	$/mcf	1.1900	1.1900	1.1900	1.1900	1.1900	1.1900	
BL Factor	mcf	1.4268	1.4268	1.4268	1.4268	1.4268	1.4268	
HSF Factor	mcf/hdd	0.014822	0.014822	0.014822	0.014822	0.014822	0.014822	
WNA Customers		153,089	156,987	163,813	159,519	164,121	158,931	159,410
WNA Revenue	$	248,039	-576,176	-708,774	333,646	110,470	-127,196	-719,992
Avg. WNA / Heating Customer	$	1.62	(3.67)	(4.33)	2.09	0.67	(0.80)	(4.52)
COMMERCIAL								
R Factor	$/mcf	1.0697	1.0697	1.0697	1.0697	1.0697	1.0697	
BL Factor	mcf	8.0378	8.0378	8.0378	8.0378	8.0378	8.0378	
HSF Factor	mcf/hdd	0.043907	0.043907	0.043907	0.043907	0.043907	0.043907	
WNA Customers		17,399	18,054	18,401	17,943	18,577	17,824	18,033
WNA Revenue	$	78,540	-200,148	-233,069	105,459	31,715	-34,723	-252,227
Avg. WNA / Heating Customer	$	4.51	(11.09)	(12.67)	5.88	1.71	(1.95)	(13.99)
PUBLIC AUTHORITY								
R Factor	$/mcf	0.9218	0.9218	0.9218	0.9218	0.9218	0.9218	
BL Factor	mcf	19.8038	19.8038	19.8038	19.8038	19.8038	19.8038	
HSF Factor	mcf/hdd	0.154335	0.154335	0.154335	0.154335	0.154335	0.154335	
WNA Customers		1,577	1,627	1,655	1,629	1,705	1,611	1,634
WNA Revenue	$	18,325	-44,733	-60,645	25,132	10,248	-10,570	-62,244
Avg. WNA / Heating Customer	$	11.62	(27.49)	(36.64)	15.43	6.01	(6.56)	(38.09)
TOTAL								
WNA Revenue	$	344,903	-821,058	-1,002,487	464,236	152,432	-172,488	-1,034,462
WEATHER								
Billing HDD'S Actual		245	850	1,161	814	601	460	4,131
Billing HDD'S Normal		330	644	924	933	638	413	3,882
Warmer(Colder) then Normal	%	25.8	-32.0	-25.6	12.8	5.8	-11.4	-6.4
Calendar HDD'S Actual		602	1,190	999	648	682	161	4,282
Calendar HDD'S Normal		516	859	1,006	797	555	247	3,980
Warmer(Colder) then Normal	%	-16.7	-38.5	0.7	18.7	-22.9	34.8	-7.6

Atmos Energy Corporation (KY Division)
WNA Summary Report
2001-2002 Heating Season
November - April

		2001-2002 Heating Season						
		November	December	January	February	March	April	Total
RESIDENTIAL								
R Factor	$/mcf	1.1900	1.1900	1.1900	1.1900	1.1900	1.1900	
BL Factor	mcf	1.3757	1.3757	1.3757	1.3757	1.3757	1.3757	
HSF Factor	mcf/hdd	0.014202	0.014202	0.014202	0.014202	0.014202	0.014202	
WNA Customers		150,563	153,925	155,427	156,056	157,102	155,959	155,959
WNA Revenue	$	121,806	531,085	166,900	705,938	37,251	-76,092	1,486,887
Avg. WNA / Heating Customer	$	0.81	3.45	1.07	4.52	0.24	(0.49)	9.53
COMMERCIAL								
R Factor	$/mcf	1.0630	1.0630	1.0630	1.0630	1.0630	1.0630	
BL Factor	mcf	7.9536	7.9536	7.9536	7.9536	7.9536	7.9536	
HSF Factor	mcf/hdd	0.044815	0.044815	0.044815	0.044815	0.044815	0.044815	
WNA Customers		17,105	17,561	17,678	17,740	17,905	17,785	17,629
WNA Revenue	$	31,573	155,766	51,199	219,540	4,660	-23,213	439,524
Avg. WNA / Heating Customer	$	1.85	8.87	2.90	12.38	0.26	(1.31)	24.93
PUBLIC AUTHORITY								
R Factor	$/mcf	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990	
BL Factor	mcf	18.6689	18.6689	18.6689	18.6689	18.6689	18.6689	
HSF Factor	mcf/hdd	0.155152	0.155152	0.155152	0.155152	0.155152	0.155152	
WNA Customers		1,626	1,642	1,644	1,647	1,655	1,658	1,645
WNA Revenue	$	11,192	44,239	15,210	56,684	2,610	-5,252	124,684
Avg. WNA / Heating Customer	$	6.88	26.94	9.25	34.42	1.58	(3.17)	75.78
TOTAL								
WNA Revenue	$	164,571	731,090	233,309	982,162	44,521	-104,557	2,051,095
WEATHER								
Billing HDD'S Actual		345	430	928	721	621	450	3,495
Billing HDD'S Normal		377	683	963	974	650	391	4,038
Warmer(Colder) then Normal	%	8.5	37.0	3.6	26.0	4.5	-15.1	13.4
Calendar HDD'S Actual		337	702	777	720	596	223	3,355
Calendar HDD'S Normal		516	859	1,006	797	555	247	3,980
Warmer(Colder) then Normal	%	34.7	18.3	22.8	9.7	-7.4	9.7	15.7

Atmos Energy Corporation (KY Division)
WNA Summary Report
2002-2003 Heating Season
November - April

		2002-2003 Heating Season						
		November	December	January	February	March	April	Total
RESIDENTIAL								
R Factor	$/mcf	1.1900	1.1900	1.1900	1.1900	1.1900	1.1900	
BL Factor	mcf	1.3315	1.3315	1.3315	1.3315	1.3315	1.3315	
HSF Factor	mcf/hdd	0.013792	0.013792	0.013792	0.013792	0.013792	0.013792	
WNA Customers		156,789	158,591	159,832	160,676	160,129	159,139	159,193
WNA Revenue	$	-168,698	-305,638	122,459	-273,129	-178,045	156,926	-646,125
Avg. WNA / Heating Customer	$	(1.08)	(1.93)	0.77	(1.70)	(1.11)	0.99	(4.06)
COMMERCIAL								
R Factor	$/mcf	1.1370	1.1370	1.1370	1.1370	1.1370	1.1370	
BL Factor	mcf	7.5508	7.5508	7.5508	7.5508	7.5508	7.5508	
HSF Factor	mcf/hdd	0.040816	0.040816	0.040816	0.040816	0.040816	0.040816	
WNA Customers		17,656	17,827	17,941	17,998	17,960	17,779	17,860
WNA Revenue	$	-51,026	-98,003	36,702	-94,159	-56,976	47,593	-215,869
Avg. WNA / Heating Customer	$	(2.89)	(5.50)	2.05	(5.23)	(3.17)	2.68	(12.09)
PUBLIC AUTHORITY								
R Factor	$/mcf	1.0590	1.0590	1.0590	1.0590	1.0590	1.0590	
BL Factor	mcf	19.6548	19.6548	19.6548	19.6548	19.6548	19.6548	
HSF Factor	mcf/hdd	0.144676	0.144676	0.144676	0.144676	0.144676	0.144676	
WNA Customers		1,658	1,654	1,653	1,655	1,659	1,662	1,657
WNA Revenue	$	-17,694	-28,533	8,893	-25,437	-15,614	14,023	-64,362
Avg. WNA / Heating Customer	$	(10.67)	(17.25)	5.38	(15.37)	(9.41)	8.44	(38.85)
TOTAL								
WNA Revenue	$	-237,418	-432,174	168,054	-392,725	-250,635	218,542	-926,356
WEATHER								
Billing HDD'S Actual		431	806	816	1059	728	301	4,141
Billing HDD'S Normal		358	650	924	941	635	384	3,892
Warmer(Colder) then Normal	%	-20.4	-24.0	11.7	-12.5	-14.6	21.6	-6.4
Calendar HDD'S Actual		621	848	1120	865	510	205	4,169
Calendar HDD'S Normal		516	859	1,006	797	555	247	3,980
Warmer(Colder) then Normal	%	-20.3	1.3	-11.3	-8.5	8.1	17.0	-4.7

Atmos Energy Corporation (KY Division)
WNA Summary Report
2003-2004 Heating Season
November - April

		2003-2004 Heating Season						
		November	December	January	February	March	April	Total
RESIDENTIAL								
R Factor	$/mcf	1.1900	1.1900	1.1900	1.1900	1.1900	1.1900	
BL Factor	mcf	1.3998	1.3998	1.3998	1.3998	1.3998	1.3998	
HSF Factor	mcf/hdd	0.013603	0.013603	0.013603	0.013603	0.013603	0.013603	
WNA Customers		153,602	156,249	157,100	159,012	159,533	157,000	157,083
WNA Revenue	$	177,665	101,203	336,000	-123,323	221,352	74,024	786,922
Avg. WNA / Customer	$	1.16	0.65	2.14	(0.78)	1.39	0.47	5.01
COMMERCIAL								
R Factor	$/mcf	1.1240	1.1240	1.1240	1.1240	1.1240	1.1240	
BL Factor	mcf	7.1981	7.1981	7.1981	7.1981	7.1981	7.1981	
HSF Factor	mcf/hdd	0.044526	0.044526	0.044526	0.044526	0.044526	0.044526	
WNA Customers		17,400	17,735	17,828	17,901	17,930	17,738	17,755
WNA Revenue	$	65,202	32,141	117,158	-45,299	77,922	22,197	269,321
Avg. WNA / Customer	$	3.75	1.81	6.57	(2.53)	4.35	1.25	15.17
PUBLIC AUTHORITY								
R Factor	$/mcf	1.0270	1.0270	1.0270	1.0270	1.0270	1.0270	
BL Factor	mcf	21.4909	21.4909	21.4909	21.4909	21.4909	21.4909	
HSF Factor	mcf/hdd	0.148968	0.148968	0.148968	0.148968	0.148968	0.148968	
WNA Customers		1,654	1,673	1,669	1,668	1,671	1,671	1,668
WNA Revenue	$	19,857	9,725	30,993	-11,313	22,431	7,044	78,738
Avg. WNA / Customer	$	12.01	5.81	18.57	(6.78)	13.42	4.22	47.21
TOTAL								
WNA Revenue	$	262,725	143,069	484,151	-179,935	321,706	103,265	1,134,981
WEATHER								
Billing HDD'S Actual		239	586	874	938	600	402	3,639
Billing HDD'S Normal		320	630	996	893	683	431	3,953
Warmer(Colder) then Normal	%	25.3	7.0	12.2	-5.0	12.2	6.7	7.9
Calendar HDD'S Actual		417	816	971	782	448	244	3,678
Calendar HDD'S Normal		516	859	1,006	797	555	247	3,980
Warmer(Colder) then Normal	%	19.2	5.0	3.5	1.9	19.3	1.2	7.6

Atmos Energy Corporation (KY Division)
WNA Summary Report
2004-2005 Heating Season
November - April

		2004-2005 Heating Season						
		November	December	January	February	March	April	Total
RESIDENTIAL								
R Factor	$/mcf	1.1900	1.1900	1.1900	1.1900	1.1900	1.1900	
BL Factor	mcf	1.3445	1.3445	1.3445	1.3445	1.3445	1.3445	
HSF Factor	mcf/hdd	0.013673	0.013673	0.013673	0.013673	0.013673	0.013673	
WNA Customers		152,832	156,212	157,010	159,346	159,253	158,060	157,119
WNA Revenue	$	241,130	130,364	379,178	373,663	52,760	30,297	1,207,392
Avg. WNA / Customer	$	1.58	0.83	2.41	2.34	0.33	0.19	7.68
COMMERCIAL								
R Factor	$/mcf	1.1280	1.1280	1.1280	1.1280	1.1280	1.1280	
BL Factor	mcf	8.2652	8.2652	8.2652	8.2652	8.2652	8.2652	
HSF Factor	mcf/hdd	0.042067	0.042067	0.042067	0.042067	0.042067	0.042067	
WNA Customers		17,413	17,767	17,755	17,984	17,923	17,781	17,771
WNA Revenue	$	77,009	37,681	132,680	123,522	11,418	13,499	395,809
Avg. WNA / Customer	$	4.42	2.12	7.47	6.87	0.64	0.76	22.27
PUBLIC AUTHORITY								
R Factor	$/mcf	1.0370	1.0370	1.0370	1.0370	1.0370	1.0370	
BL Factor	mcf	22.8017	22.8017	22.8017	22.8017	22.8017	22.8017	
HSF Factor	mcf/hdd	0.146240	0.146240	0.146240	0.146240	0.146240	0.146240	
WNA Customers		1,655	1,646	1,636	1,654	1,650	1,649	1,648
WNA Revenue	$	26,773	10,539	34,196	33,536	4,838	2,483	112,365
Avg. WNA / Customer	$	16.18	6.40	20.90	20.28	2.93	1.51	68.17
TOTAL								
WNA Revenue	$	344,912	178,584	546,054	530,721	69,016	46,279	1,715,566
WEATHER								
Billing HDD'S Actual		199	601	836	745	675	409	3,465
Billing HDD'S Normal		319	658	970	882	693	424	3,946
Warmer(Colder) then Normal	%	37.6	8.7	13.8	15.5	2.6	3.5	12.2
Calendar HDD'S Actual		427	893	783	637	636	231	3,607
Calendar HDD'S Normal		516	859	1,006	797	555	247	3,980
Warmer(Colder) then Normal	%	17.2	-4.0	22.2	20.1	-14.6	6.5	9.4

Atmos Energy Corporation (KY Division)
WNA Summary Report
2005-2006 Heating Season
November - April

		2005-2006 Heating Season						
		November	December	January	February	March	April	Total
RESIDENTIAL								
R Factor	$/mcf	1.1900	1.1900	1.1900	1.1900	1.1900	1.1900	
BL Factor	mcf	1.2450	1.2450	1.2450	1.2450	1.2450	1.2450	
HSF Factor	mcf/hdd	0.013418	0.013418	0.013418	0.013418	0.013418	0.013418	
WNA Customers		153,572	156,105	157,778	158,020	157,942	157,142	156,760
WNA Revenue	$	48,860	-249,524	423,730	480,059	126,216	26,673	856,014
Avg. WNA / Customer	$	0.32	(1.60)	2.69	3.04	0.80	0.17	5.46
COMMERCIAL								
R Factor	$/mcf	1.1260	1.1260	1.1260	1.1260	1.1260	1.1260	
BL Factor	mcf	9.3018	9.3018	9.3018	9.3018	9.3018	9.3018	
HSF Factor	mcf/hdd	0.039134	0.039134	0.039134	0.039134	0.039134	0.039134	
WNA Customers		17,690	18,044	18,078	18,120	18,068	17,949	17,992
WNA Revenue	$	15,392	-89,665	154,454	153,566	42,788	10,098	286,633
Avg. WNA / Customer	$	0.87	(4.97)	8.54	8.47	2.37	0.56	15.93
PUBLIC AUTHORITY								
R Factor	$/mcf	1.0350	1.0350	1.0350	1.0350	1.0350	1.0350	
BL Factor	mcf	21.2899	21.2899	21.2899	21.2899	21.2899	21.2899	
HSF Factor	mcf/hdd	0.151728	0.151728	0.151728	0.151728	0.151728	0.151728	
WNA Customers		1,634	1,637	1,648	1,638	1,634	1,629	1,637
WNA Revenue	$	4,862	-22,948	45,518	43,546	12,716	5,460	89,154
Avg. WNA / Customer	$	2.98	(14.02)	27.62	26.58	7.78	3.35	54.47
TOTAL								
WNA Revenue	$	69,114	-362,137	623,702	677,171	181,720	42,231	1,231,801
WEATHER								
Billing HDD'S Actual		292	753	807	686	669	379	3,586
Billing HDD'S Normal		318	648	972	878	722	387	3,925
Warmer(Colder) then Normal	%	8.2	-16.2	17.0	21.9	7.3	2.1	8.6
Calendar HDD'S Actual		483	950	656	779	536	145	3,549
Calendar HDD'S Normal		516	859	1,006	797	555	247	3,980
Warmer(Colder) then Normal	%	6.4	-10.6	34.8	2.3	3.4	41.3	10.8