

**UTILICORP UNITED**

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November 2, 2001

Mr. Dale Hardy Roberts, Secretary/Chief Regulatory Law Judge  
Missouri Public Service Commission  
200 Madison St  
Jefferson City, MO 65102

**FILED**<sup>3</sup>

NOV 05 2001

Missouri Public  
Service Commission

RE: Case No. GR-2001-461

Dear Mr. Roberts:

Enclosed are an original and two copies of PSC MO. No. 5, 21st Revised Sheet No. 43, 24th Revised Sheet No. 44 and 14th Revised Sheet No. 44.1 reflecting a change in the Purchased Gas Adjustment, Actual Cost Adjustment, Refund Factor, Take-Or-Pay Factor, Transition Cost Factor and Deferred Carrying Cost Balance of the Missouri Public Service Purchased Gas Adjustment Clause.

The Purchased Gas Adjustment Clause for Missouri Public Service (MPS) requires an annual actual cost adjustment for the over recovery or under recovery resulting from the operation of the Regular Purchased Gas Adjustment section of the Purchased Gas Adjustment Clause and a calculation of the Winter Period Purchased Gas Adjustment. Reconciliations for the Refund Factors, Transition Cost Factors and Deferred Carrying Cost Balance are also required.

**Purchased Gas Adjustment**

Enclosures 1, 2 and 3 reflect the Purchased Gas Adjustment (PGA) calculations for the Southern System, Northern System and Eastern System. Each PGA has been developed using the Nov FERC index fixed gas cost and storage for the months of November 2001 through March 2002. The tariff rate changes for the Southern System are based on the Williams Gas Pipelines Central, Inc. filings of their FERC Gas Tariffs, Eleventh Revised Sheet No. 6, Eighth Revised Sheet No. 6A and Third Revised Sheet No. 6B. The tariff rate changes for the Northern System and Eastern System are based on the Panhandle Eastern Pipe Line Company filings of their FERC Gas Tariffs, Sixty-third Revised Sheet No. 5, Sixty-sixth Revised Sheet No. 7, Twelfth Revised Sheet No. 9, Thirteenth Revised Sheet No. 11 and Twenty-Seven Revised Sheet No. 19.

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## **Actual Cost Adjustment**

Enclosed as Enclosure 4 are minimum filing requirement schedules that are the basis of the Actual Cost Adjustment portion of this filing. Schedule 4 of Enclosure 4 is a summary showing revenue, purchased gas costs, and over or under recovery for the year ended August 2001 and the proposed changes in the ACA rates to be effective November 19, 2001. Detailed supporting workpapers are available for the Commission Staff audit.

The summary schedule shows that revenue recovery was less than purchased gas cost in the amount of \$6,117,963.64 for the Southern System, less than purchased gas cost in the amount of \$774,704.79 for the Northern System and less than purchased gas cost in the amount of \$1,094,047.50 which includes a deferral of \$290,899.66 for the Eastern System. Total revenue recovery was \$8,081,253.20 less than purchased gas cost.

Under separate cover, Missouri Public Service has filed a waiver requesting a variance from the provision of its tariff that requires the recovery of the ACA balance over a one-year period. MPS requests that it be allowed to recover that balance on its Eastern System over a three-year period.

## **Southern System Refund Factor**

Enclosed as Enclosure 5 is a summary schedule detailing the activity for the refund factor under the Southern System. MPS received two refunds from Williams Gas Pipelines Central, Inc. On January 26, 2001 a refund in the amount of \$38,053.78 relating to Federal Energy Regulatory Commission (FERC) Docket No. RP93-109 was received. On February 23, 2001 a refund for \$22,723.01 relating to Docket No. IN01-2-000 was received. Interest has been calculated by MPS at the annual rate of six percent from the date the refunds were received by MPS until six months after the refund rate is scheduled to be in effect in accordance with our Purchased Gas Adjustment Clause. Missouri Public Service has determined a new refund factor for the Southern System.

## **Northern System Refund Factor**

Enclosed as Enclosure 5A is a summary schedule that details the activity for the refund factor under the Northern System. MPS has received no refunds from Panhandle Eastern Pipe Line Co. Missouri Public Service has determined a new refund factor of zero for the Northern System.

## **Deferred Carrying Cost Balance**

Enclosures 6, 7 and 8 reflect the Deferred Carrying Cost Balances for the Southern System, Northern System and Eastern System. Carrying costs are calculated on all Deferred Carrying Cost Balances that exceed ten percent of an average annual gas cost

threshold. This results in carrying costs collected from the customer in the amount of \$109,760 for the Southern System, \$12,442 for the Northern System, and \$33,607 for the Eastern System.

Enclosures 9, 10 and 11 reflect the seasonal revenue impact associated with the gas cost recovery portion of the rates. The seasonal revenue impact results in an increase in the amount of \$6,346,828 or 61.42% for the Southern System, an increase in the amount of \$2,789,081 or 62.03% for the Northern System and an increase in the amount of \$875,215 or 50.74% for the Eastern System.

Missouri Public Service respectfully requests that these rates become effective with volumes taken on and after November 19, 2001

Sincerely,



Karen Russell  
Regulatory Manager

Enclosures

cc: Office of the Public Counsel (2)

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

P.S.C. MO. No. 5 23rd (Original) SHEET NO. 43  
 (Revised)

Cancelling P.S.C. MO. No. 5 22nd (Original) SHEET NO. 43  
 (Revised)

MISSOURI PUBLIC SERVICE  
 KANSAS CITY, MO 64138

FOR: Southern System

PURCHASED GAS ADJUSTMENT CLAUSE  
 (CONTINUED)

Adjustment Statement (Southern System)

As provided in this Purchased Gas Adjustment Clause, the following adjustment(s) will be made to the applicable rate schedules:

	Rate Schedule <u>GNG</u>	Rate Schedule <u>LVF</u>	Rate Schedule <u>LVI</u>
Regular PGA	\$.48835	\$.48835	\$.44699
Actual Cost Adjustment	\$.16003	\$.16003	\$(-.00777)
Refunds	\$.00611	\$.00611	\$ -0-
TOP Factor	\$ -0-	\$ -0-	\$ -0-
TC Factor	\$ -0-	\$ -0-	\$ -0-
Total PGA Per Ccf	\$.65449	\$.65449	\$.43922

The TOP and TC Factors, as provided in Sheets 39 through 40, shall also apply to all Ccf delivered to transportation customers on Missouri Public Service's Southern System except as provided for on Sheet No. 20.

The ACA, Refund, TOP and TC factors as contained herein shall apply to all Ccf delivered to end-users receiving service under the Experimental SVTS-A schedule on an interim basis until the effective date of the Company's scheduled winter 2001 PGA filing.

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

P.S.C. MO. No. 5 26th (Original) SHEET NO. 44  
 (Revised)

Cancelling P.S.C. MO. No. 5 25th (Original) SHEET NO. 44  
 (Revised)

MISSOURI PUBLIC SERVICE  
 KANSAS CITY, MO 64138

FOR: Northern System

PURCHASED GAS ADJUSTMENT CLAUSE  
 (CONTINUED)

Adjustment Statement (Northern System)

As provided in this Purchased Gas Adjustment Clause, the following adjustment(s) will be made to the applicable rate schedules:

	Rate Schedule <u>GNG</u>	Rate Schedule <u>LVF</u>	Rate Schedule <u>LVI</u>
Regular PGA	\$ .62121	\$ .62121	\$ .40476
Actual Cost Adjustment	\$ .05274	\$ .05274	\$ -0-
Refunds	\$ -0-	\$ -0-	\$ -0-
TOP Factor	\$ -0-	\$ -0-	\$ -0-
TC Factor	\$ -0-	\$ -0-	\$ -0-
Total PGA Per Ccf	\$ .67395	\$ .67395	\$ .40476

The TOP and TC Factors, as provided in Sheets 39 through 40, shall also apply to all Ccf delivered to transportation customers on Missouri Public Service's Northern System except as provided for on Sheet No. 20.

The ACA, Refund, TOP and TC factors as contained herein shall apply to all Ccf delivered to end-users receiving service under the Experimental SVTS-A schedule on an interim basis until the effective date of the Company's scheduled winter 2001 PGA filing.

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

P.S.C. MO. No. 5 16th (Original) SHEET NO. 44.1  
 (Revised)  
 Cancelling P.S.C. MO. No. 5 15th (Original) SHEET NO. 44.1  
 (Revised)

MISSOURI PUBLIC SERVICE  
 KANSAS CITY, MO 64138

FOR: Eastern System

PURCHASED GAS ADJUSTMENT CLAUSE  
 (CONTINUED)

Adjustment Statement (Eastern System)

As provided in this Purchased Gas Adjustment Clause, the following adjustment(s) will be made to the applicable rate schedules:

	Rate Schedule <u>GNG</u>	Rate Schedule <u>LVF</u>	Rate Schedule <u>LVI</u>
Regular PGA	\$ .79147	\$ .79147	\$ .64916
Actual Cost Adjustment	\$ .28862	\$ .28862	\$ -0-
Refunds	\$ -0-	\$ -0-	\$ -0-
TOP Factor	\$ -0-	\$ -0-	\$ -0-
TC Factor	\$ -0-	\$ -0-	\$ -0-
Total PGA Per Ccf	\$ 1.08009	\$ 1.08009	\$ .64916

The TOP and TC Factors, as provided in Sheets 39 through 40, shall also apply to all Ccf delivered to transportation customers on Missouri Public Service's Eastern System except as provided for on Sheet No. 20.

The ACA, Refund, TOP and TC factors as contained herein shall apply to all Ccf delivered to end-users receiving service under the Experimental SVTS-A schedule on an interim basis until the effective date of the Company's scheduled winter 2001 PGA filing.

**MISSOURI PUBLIC SERVICE**  
**Southern System Annualized Gas Cost Calculation**  
**To Reflect Current WNG & Spot Market Rates**

**Enclosure 1**

<b>FIRM</b>	<b>Annual Volume</b>	<b>Monthly Capacity Reserved</b>	<b>No. of Mth Reserved</b>	<b>Tariff Rate</b>	<b>Annual Cost</b>
<b>Williams Natural Gas</b>					
<b>TSS</b>					
No-Notice Fee		39,618	12	\$0.0154	\$7,321
Reservation - FSS Deliverability		25,412	12	\$0.5083	\$155,003
Reservation - FTS-Production		13,841	12	\$5.6118	\$932,075
Reservation - FTS-Market		39,618	12	\$2.8014	\$1,331,830
GRI		39,618	12	\$0.0550	\$26,148
<b>FTS</b>					
Production - Reservation		11,845	12	\$5.6118	\$797,661
Production - Balancing		11,845	12	\$0.1604	\$22,799
Market - Reservation		10,491	12	\$2.8014	\$352,674
Market - Balancing		10,491	12	\$0.1604	\$20,193
Market - GRI		10,491	12	\$0.0550	\$6,924
<b>GSR Costs</b>					
					\$250,608
Spot Market Purchases	3,896,019			\$3.7903	\$14,767,081
Total Annual Cost					<u>\$18,670,317</u>
Sales Volume at Burnertip	3,823,123				
<b>Cost per MCF at Burnertip</b>					<u><b>\$4.8835</b></u>

Highest WACOG (Winter Period)	Nov 98 - Mar 99	Nov 99 - Mar 00	Nov 00 - Mar 01	Average WACOG
	\$2.4616	\$3.6118	\$8.8701	<b>\$4.9812</b>
<b>Highest Avg WACOG-Winter Period (Avg of winter seasons with the highest of 3 averages)</b>				<b>\$6.9256</b>
				<b>\$3.1851</b>

**INTERRUPTIBLE**

<b>Williams Natural Gas</b>					
<b>ITS-P</b>					
Commodity	126,964			@150% \$0.3090	\$39,232
<b>ITS-M</b>					
Commodity	125,491			@150% \$0.1610	\$20,198
Spot Market Price Per MCF	129,542			\$3.7903	\$491,001
Total Annual Cost					<u>\$550,431</u>
Sales Volume at Burnertip	123,143				
<b>Cost per MCF at Burnertip</b>					<u><b>\$4.4699</b></u>

**MISSOURI PUBLIC SERVICE - SOUTHERN SYSTEM**

**Gas Cost Inputs**

MPS Line Loss 1.871%  
 Annual Burnertip Sales 3,946,266

WNG Rates

**Firm Rates**

TSS  
 No-Notice Fee \$0.0154  
 Reservation - FSS Deliverability \$0.5083  
 Reservation - FSS Capacity \$0.0290  
 Reservation - FTS-P \$5.6118  
 Reservation - FTS-M \$2.8014  
 GRI \$0.0550

FTS  
 Production - Reservation \$5.6118  
 Production - Balancing \$0.1604  
 Market - Reservation \$2.8014  
 Market - Balancing \$0.1604  
 Market - GRI \$0.0550

Production  
 Commodity - FTS-P \$0.0124  
 GRI Funding Unit - Commodity - Others \$0.0070  
 FERC Annual Charge Adjustment \$0.0021  
 Production Field Zone \$0.0215

Commodity - FTS-M \$0.0061  
 GRI Funding Unit - Commodity - Others \$0.0070  
 FERC Annual Charge Adjustment \$0.0021  
 Market Zone \$0.0152

Injection/Withdrawal - FSS \$0.0122

**Interruptible Rates**

ITS-P  
 Commodity-Winter \$0.1969

ITS-M  
 Commodity-Winter \$0.0982  
 GRI Funding Unit - Commodity - Others \$0.0070  
 FERC Annual Charge Adjustment \$0.0021

WNG Production Area Loss 1.99%  
 WNG Market Area Loss 1.16%  
 WNG Storage Loss 1.82%

Note: From FERC Gas Tariff: Eleventh Revised Sheet No. 6 Effective 11/1/99, Eighteenth Revised Sheet No. 6A Effective 10/1/01, and Third Revised Sheet No. 6B Effective 1/1/01.

Calculated Inputs

	<u>Firm</u>	<u>Storage</u>	Total <u>Firm</u>	<u>Interruptible</u>	Total <u>System</u>
Annual Throughput at Burnertip Per GR-93-172	2,796,691	1,026,432	3,823,123	123,143	3,946,266
Annual Throughput at Citygate	2,850,016	1,046,003	3,896,019	125,491	4,021,508
Annual Throughput at Production Area	2,876,348	1,065,393	3,941,741	126,964	4,068,705
Annual Throughput at Wellhead	2,934,749	1,087,025	4,021,774	129,542	4,151,316

Missouri Public Service  
Division of UtiliCorp United Inc.  
Southern System  
**Current Gas Cost Calculation**

	<u>Nov-01</u>	<u>Dec-01</u>	<u>Jan-02</u>	<u>Feb-02</u>	<u>Mar-02</u>	<u>Totals</u>
<b>SUMMARY OF COMMODITY COSTS</b>						
Sales Requirements	522,967	977,445	773,482	650,091	507,283	3,431,268
WNG Market Area Loss	1.16%	1.16%	1.16%	1.16%	1.16%	
WNG Production Area Loss	1.99%	1.99%	1.99%	1.99%	1.99%	
Total Supply - Fuel Loss	539,848	1,008,995	798,449	671,075	523,657	
Storage Injection						0
Storage Injection Loss	1.82%	1.82%	1.82%	1.82%	1.82%	
Total Storage - Fuel Loss	0	0	0	0	0	
(Storage injection is noted on spreadsheet but not included in commodity cost calculation because MPS does not pay for storage until it is withdrawn in the winter months.)						
Purchase Requirements	539,848	1,008,995	798,449	671,075	523,657	3,542,024
Contracted Fixed Price Supply	132,300	136,710	136,710	123,480	136,710	665,910
Contracted Price	\$ 3.6519	\$ 3.6519	\$ 3.6519	\$ 3.6519	\$ 3.6519	
Total Cost	\$ 483,146	\$ 499,251	\$ 499,251	\$ 450,937	\$ 499,251	2,431,836
(Contracted Fixed Price Supply only applies in the winter months.)						
Total Supply	302,724	662,638	452,092	337,948	282,123	2,037,525
Forecasted Price (NYMEX-WNG Basis)*	\$ 3.117	\$ 3.205	\$ 3.349	\$ 3.339	\$ 3.274	
Total Cost	\$ 943,591	\$ 2,123,754	\$ 1,514,056	\$ 1,128,408	\$ 923,671	\$ 6,633,480
Storage Withdrawal	104,824	209,647	209,647	209,647	104,824	838,589
Storage WACOG	\$ 5.0428	\$ 5.0428	\$ 5.0428	\$ 5.0428	\$ 5.0428	
Total Cost	\$ 528,600	\$ 1,057,198	\$ 1,057,198	\$ 1,057,198	\$ 528,600	\$ 4,228,794
<u>Forecasted Gas Commodity Cost</u>	1,955,337	3,680,203	3,070,505	2,636,543	1,951,522	13,294,110
<u>Forecasted Sales Gas Quantity</u>	539,848	1,008,995	798,449	671,075	523,657	3,542,024
<u>Gas Cost (Commodity) Dth</u>						\$3.7533
<b>SUMMARY OF UPSTREAM COSTS</b>						
Williams Natural Gas Pipeline - Firm						
FT Commodity (Production Area)	539,848	1,008,995	798,449	671,075	523,657	
FT Commodity (Market Area)	529,105	988,916	782,560	657,721	513,237	
Total Units	1,068,953	1,997,911	1,581,009	1,328,796	1,036,894	7,013,563
Cost/Dth - Production Area	\$0.0218	\$0.0218	\$0.0218	\$0.0218	\$0.0218	
Cost/Dth - Market Area	\$0.0155	\$0.0155	\$0.0155	\$0.0155	\$0.0155	
Total WNG Commodity Costs	\$19,970	\$37,324	\$29,536	\$24,824	\$19,371	\$131,025
<u>Forecasted Northern Upstream Costs</u>	19,970	37,324	29,536	24,824	19,371	131,025
<u>Forecasted Firm Sales Quantity</u>	539,848	1,008,995	798,449	671,075	523,657	3,542,024
<u>Upstream Cost/Dth</u>						\$0.0370
						\$ 3.7903

Missouri Public Service  
Division of UtiliCorp United Inc.  
Southern System  
**Gas Commodity Cost Calculation**

INSIDE FERC NOV 2001	\$	3.05
WNG Market Area Loss		1.16%
WNG Production Area Loss		<u>1.99%</u>
WNG Index Adjusted for Fuel	\$	3.1484
WNG Cost/Dth Field Zone		\$0.0215
WNG Cost/Dth - Market Zone		<u>\$0.0152</u>
		\$3.1851
Total Gas Commodity Costs		<b>\$3.1851</b>

**MISSOURI PUBLIC SERVICE**  
**Northern System Annualized Gas Cost Calculation**  
**To Reflect Current PEPL & Spot Market Rates**

**Enclosure 2**

<b>FIRM</b>	<b>Annual Volume</b>	<b>Monthly Capacity Reserved</b>	<b>No. Of Mth Reserved</b>	<b>Tariff/ Contracted Rate</b>	<b>Annual Cost</b>
<b>Panhandle Eastern Pipe Line</b>					
<b>Contract 17005</b>					
<b>EFT Reservation Rates</b>					
Field Zone Reservation		18,000	5	\$4.1673	\$375,057
Market Zone Access		18,000	5	\$2.8994	\$260,944
Market Zone Mileage		18,000	5	\$1.5960	\$143,639
Field Zone Reservation		10,000	7	\$4.1673	\$291,711
Market Zone Access		10,000	7	\$2.8994	\$202,956
Market Zone Mileage		10,000	7	\$1.5960	\$111,719
					\$0
					\$0
<b>Contract 17004</b>					
FS Storage	800,000			\$2.9472	\$2,357,760
Spot Market Purchases	1,521,875			\$3.5354	\$5,380,437
Total Annual Cost					<u>\$9,124,223</u>
Sales Volume at Burnertip	1,468,777				
<b>Cost per MCF at Burnertip</b>					<u><b>\$6.2121</b></u>

Highest WACOG (Winter Period)	Nov 98 - Mar 99	Nov 99 - Mar 00	Nov 00 - Mar 01	Average WACOG
	\$2.1525	\$2.3949	\$6.2412	<b>\$3.5962</b>
<b>Highest Avg WACOG-Winter Period (Avg of winter seasons with the highest 3 averages)</b>				<b>\$4.9187</b>
				<b>\$3.1818</b>

November 2001 Gas Commodity Costs

<b>INTERRUPTIBLE</b>			
<b>Panhandle Eastern Pipe Line</b>			
<b>IT Interruptible Rates</b>			
		<b>@150%</b>	
Field Zone		\$0.2615	\$0.2615
Market Zone Access		\$0.1376	\$0.1376
Market Zone Mileage		\$0.0999	\$0.0999
GRI Funding Unit		\$0.0105	\$0.0105
ACA Unit Charge		\$0.0033	\$0.0033
TOP Volumetric Surcharge		\$0.0000	\$0.0000
Settlement Surcharges		(\$0.0005)	(\$0.0005)
Canadian Resolution Surcharges		\$0.0000	\$0.0000
Stranded Transportation Cost Surcharge		\$0.0000	\$0.0000
Miscellaneous Stranded Costs Surcharge		\$0.0000	(\$0.0000)
Spot Market Price Per MCF	\$3.5354		\$3.5354
Total Annual Cost			<u>\$4.0476</u>
Sales Volume at Burnertip			
<b>Cost per MCF at Burnertip</b>			<u><b>\$4.0476</b></u>

**MISSOURI PUBLIC SERVICE - NORTHWESTERN SYSTEM**  
**Gas Cost Inputs**

MPS Line Loss 3.489%  
 Annual Burnertip Sales 1,468,777

<u>PEPL Rates</u>	Tariff	Contract 17005
<u>PEPL EFT Reservation Rates</u>	<u>Rate</u>	<u>Discount Rate</u>
Field Zone Reservation	\$4.7000	\$4.1673
Market Zone Access	\$3.2700	\$2.8994
Market Zone Mileage 201-300 Block	\$1.8000	\$1.5960
GRI Funding Unit	\$0.0900	
Settlement Surcharges	\$0.0000	
Canadian Resolution Surcharges	\$0.0000	
GSR Surcharge	\$0.0000	
Stranded Transportation Cost Surcharge	\$0.0000	
Miscellaneous Stranded Costs Surcharge	\$0.0000	

<u>PEPL EFT Commodity Rates</u>	Rate
Field Zone Commodity	\$0.0213
Market Zone Access	\$0.0024
Market Zone Mileage	\$0.0075
GRI Funding Unit	\$0.0000
ACA Unit Charge	\$0.0021
TOP Volumetric Surcharge	\$0.0000
Settlement Surcharges	(\$0.0003)
Total Market Zone Commodity	\$0.0117

<u>PEPL IT Interruptible Rates</u>	Rate
Field Zone	\$0.1743
Market Zone Access	\$0.0917
Market Zone Mileage	\$0.0666
GRI Funding Unit	\$0.0070
ACA Unit Charge	\$0.0022
TOP Volumetric Surcharge	\$0.0000
Settlement Surcharges	(\$0.0003)
Canadian Resolution Surcharges	\$0.0000
Stranded Transportation Cost Surcharge	\$0.0000
Miscellaneous Stranded Costs Surcharge	\$0.0000

<u>Seasonal Sales Volume @ Burnertip</u>	
Jan	288,860
Feb	265,604
Mar	194,613
Apr	117,502
May	64,871
Jun	44,063
Jul	34,272
Aug	33,047
Sep	36,719
Oct	51,407
Nov	118,726
Dec	219,093
	1,468,777

PEPL Gathering Loss	0.69%
PEPL Field Zone Loss	1.13%
PEPL Market Zone Loss	1.35%
PEPL Storage Injection Loss	1.26%
PEPL Storage Withdrawal Loss	0.23%

Note: From FERC Gas Tariff: PEPL Sixth-third Revised Sheet No. 5 Effective 11/1/01, Sixty-Sixth Revised Sheet No. 7 Effective 11/1/01, Thirteenth Revised Sheet No. 11 Effective 11/01/00 and Twenty-Seventh Revised Sheet No. 19 Effective 10/01/01.

<u>Calculated Inputs</u>	<u>Firm</u>	<u>Storage</u>	<u>Total</u>	<u>Interruptible</u>	<u>Total</u>
	<u>Firm</u>		<u>Firm</u>		
Annual Throughput at Burnertip Per GR-93-172	886,877	581,900	1,468,777	0	1,468,777
Annual Throughput at Citygate	918,939	602,936	1,521,875	0	1,521,875
Annual Throughput at Havenpool	931,514	612,596	1,544,110	0	1,544,110
Annual Throughput at Wellhead	942,161	627,504	1,569,665	0	1,569,665

Missouri Public Service  
Division of UtiliCorp U.S. Inc.  
Northern System

**Current Gas Cost Calculation**

	<u>Nov-01</u>	<u>Dec-01</u>	<u>Jan-02</u>	<u>Feb-02</u>	<u>Mar-02</u>	<u>Totals</u>
<b>SUMMARY OF COMMODITY COSTS</b>						
Sales Requirements	167,798	327,785	261,121	232,695	190,121	1,179,520
PEPL Market Zone Fuel Loss	1.35%	1.35%	1.35%	1.35%	1.35%	
PEPL Field Zone Fuel Loss	1.13%	1.13%	1.13%	1.13%	1.13%	
Gathering Fuel Loss	0.69%	0.69%	0.69%	0.69%	0.69%	
<b>Total Supply - Fuel Loss</b>	<b>173,234</b>	<b>338,403</b>	<b>269,580</b>	<b>240,233</b>	<b>196,280</b>	

Storage Injection						0
Storage Injection Loss	<u>1.26%</u>	<u>1.26%</u>	<u>1.26%</u>	<u>1.26%</u>	<u>1.26%</u>	
<b>Total Storage - Fuel Loss</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	

(Storage injection is noted on spreadsheet but not included in commodity cost calculation because MPS does not pay for storage until it is withdrawn in the winter months.)

Purchase Requirements	173,234	338,403	269,580	240,233	196,280	1,217,730
Total Supply	73,234	138,403	69,580	40,233	96,280	417,730
Forecasted Price (NYMEX-PEPL Basis)	\$ 3.0920	\$ 3.1800	\$ 3.3240	\$ 3.3140	\$ 3.2490	
<b>Total Cost</b>	<b>\$ 226,440</b>	<b>\$ 440,122</b>	<b>\$ 231,284</b>	<b>\$ 133,332</b>	<b>\$ 312,814</b>	<b>1,343,992</b>

Storage Withdrawal (17007)	100,000	200,000	200,000	200,000	100,000	800,000
Storage WACOG (17007)	\$ 3.6519	\$ 3.6519	\$ 3.6519	\$ 3.6519	\$ 3.6519	
<b>Total Cost</b>	<b>\$ 365,190</b>	<b>\$ 730,380</b>	<b>\$ 730,380</b>	<b>\$ 730,380</b>	<b>\$ 365,190</b>	<b>\$ 2,921,520</b>

<u>Forecasted Gas Commodity Cost</u>	591,630	1,170,502	961,664	863,712	678,004	4,265,512
<u>Forecasted Sales Gas Quantity</u>	173,234	338,403	269,580	240,233	196,280	1,217,730

Gas Cost (Commodity) Dth \$3.5028

**SUMMARY OF UPSTREAM COSTS**

Panhandle Eastern Pipeline - Firm						
FT Commodity (Field Zone)	172,038	336,068	267,720	238,575	194,925	
FT Commodity (Market Zone)	<u>170,094</u>	<u>332,271</u>	<u>264,694</u>	<u>235,879</u>	<u>192,723</u>	
<b>Total Units</b>	<b>342,132</b>	<b>668,339</b>	<b>532,414</b>	<b>474,454</b>	<b>387,648</b>	<b>2,404,987</b>

Cost/Dth - Field Zone	\$0.0213	\$0.0213	\$0.0213	\$0.0213	\$0.0213	
Cost/Dth - Market Zone	<u>\$0.0117</u>	<u>\$0.0117</u>	<u>\$0.0117</u>	<u>\$0.0117</u>	<u>\$0.0117</u>	
<b>Total Panhandle Commodity Costs</b>	<b>\$5,655</b>	<b>\$11,046</b>	<b>\$8,799</b>	<b>\$7,841</b>	<b>\$6,407</b>	<b>39,748</b>

Forecasted Northern Upstream Costs 39,748

Forecasted Firm Sales Quantity 1,217,730

Upstream Cost/Dth \$0.0326

Wellhead Cost of Gas

\$ 3.5354

Missouri Public Service  
Division of UtiliCorp United Inc.  
Northern System  
**Gas Commodity Cost Calculation**

INSIDE FERC NOVEMBER 01	\$3.05	
PEPL Market Zone Fuel Loss	1.35%	
PEPL Field Zone Fuel Loss	1.13%	
Gathering Fuel Loss	<u>0.69%</u>	
PEPL Index Adjusted for Fuel	\$ 3.1488	
PEPL Cost/Dth Field Zone	\$0.0213	
PEPL Cost/Dth - Market Zone	<u>\$0.0117</u>	
	\$3.1818	
Total Gas Commodity Costs	<table border="1"><tr><td>\$3.1818</td></tr></table>	\$3.1818
\$3.1818		

**MISSOURI PUBLIC SERVICE**  
**Eastern System Annualized Gas Cost Calculation**  
**To Reflect Current PEPL & Spot Market Rates**

<b>FIRM</b>	<b>Annual/ Seasonal Volume</b>	<b>Monthly Capacity Reserved</b>	<b>No. of Mths Reserved</b>	<b>Tariff Rate</b>	<b>Annual Cost</b>
<b>Panhandle Eastern Pipe Line</b>					
Winter (Nov-Mar)					
FT Reservation (Field Zone)		5,200	5	\$4.7000	\$122,200
FT Reservation (Market Zone)		5,200	5	\$5.7600	\$149,760
					<u>\$271,960</u>
<b>Winter Sales Volume at Burnertip</b>	<b>273,300</b>				
<b>Winter Cost per MCF at Burnertip</b>					<b>\$0.9951</b>
Summer (Apr-Oct) Volumetric Rate					
100% LF of Max Rate (Fld-4 Blks)					\$0.3439
<b>Summer Cost per MCF at Burnertip</b>					<b>\$0.3439</b>
<b>Missouri Pipeline Company</b>					
Rolla					
FT Reservation		2,939	12	\$4.3181	\$152,291
Salem					
FT Reservation		2,500	12	\$1.0000	\$30,000
Owensville					
FT Reservation		1,900	12	\$0.5000	\$11,400
<b>Missouri Gas Company</b>					
Rolla					
FT Reservation		2,939	12	\$6.5000	\$229,242
Salem					
FT Reservation		2,500	12	\$13.1700	\$395,100
Owensville					
FT Reservation		1,900	12	\$8.0000	\$182,400
<b>Total Eastern System MoPipe &amp; MoGas Costs</b>					<u><u>\$1,000,433</u></u>
Spot Market Purchases	380,336			\$4.2661	\$1,622,553
<b>Total Eastern System Costs</b>					<u><u>\$2,622,986</u></u>
Sales Volume at Burnertip	<u>379,066</u>				
<b>Cost per MCF at Burnertip</b>					<b>\$6.9196</b>
<b>Winter PGA</b>					
<b>Total Cost per MCF at Burnertip</b>					<b>\$7.9147</b>
Highest WACOG (Winter Period)		Nov 98 - Mar 99	Nov 99 - Mar 00	Nov 00 - Mar 01	<b>Average WACOG</b>
		\$2.0449	\$2.6531	\$7.0924	<b>\$3.9301</b>
<b>Highest Avg WACOG-Winter Period (Avg of winter seasons with the highest of 3 averages)</b>					<b>\$5.5113</b>
					<b>November 2001 Gas Commodity Costs</b>
					<b>\$3.6388</b>

**INTERRUPTIBLE**

<b>Panhandle Eastern Pipe Line</b>					
IT (Field Zone)	\$0.1743		@ 150%		\$0.2615
IT (Market Zone)	\$0.1893		@ 150%		\$0.2839
<b>Missouri Pipeline Company</b>					
Commodity	\$0.3036				\$0.3036
<b>Missouri Gas Company</b>					
Commodity	\$1.3765				\$1.3765
Spot Market Price Per MCF	\$4.2661				\$4.2661
<b>Cost per MCF at Burnertip</b>					<b>\$6.4916</b>

**MISSOURI PUBLIC SERVICE - EASTERN SYSTEM**

**Gas Cost Inputs**

MPS Line Loss	0.334%
MoGas/MoPipe Line Loss	0.43%

**PEPL RATES**

PEPL EFT Reservation Rates

Field Zone Reservation	\$4.70
Market Zone Access	\$3.27
Market Zone Mileage 301-400 Block	\$2.40
GRI Funding Unit	\$0.0900
Settlement Surcharges	\$0.0000
Canadian Resolution Surcharges	\$0.0000
GSR Surcharge	\$0.0000
Stranded Transportation Cost Surcharge	\$0.0000
Miscellaneous Stranded Costs Surcharge	\$0.0000

PEPL EFT Commodity Rates

Market Zone Access	\$0.0006
Market Zone Mileage 301-400	\$0.0100
GRI Funding Unit	\$0.0070
ACA Unit Charge	\$0.0021
TOP	\$0.0000
Settlement Charges	(\$0.0003)

PEPL Interruptible Rates

Field Zone	\$0.1743
Market Zone Access	\$0.0917
Market Zone Mileage	\$0.0888
GRI Funding Unit	\$0.0070
ACA Unit Charge	\$0.0021
TOP Volumetric Surcharge	\$0.0000
Settlement Surcharges	(\$0.0003)
Canadian Resolution Surcharges	\$0.0000
Stranded Transportation Cost Surcharge	\$0.0000
Miscellaneous Stranded Costs Surcharge	\$0.0000

EFT Commodity Rates \$0.0194

Field Zone Commodity \$0.0195

Total EFT Commodity Rates \$0.0389

PEPL Gathering Loss	0.69%
PEPL Field Zone Loss	1.13%
PEPL Market Zone Loss	1.80%

Note: From FERC Gas Tariff: PEPL Sixth-Third Revised Sheet No. 5 Effective 11/01/01 , Sixty-Sixth Revised Sheet No. 7 Effective 11/01/01, and Twenty-Seventh Revised Sheet No. 19 Effective 10/01/01.

Annual Throughput at Burnertip	379,066
Annual Throughput at Citygate	380,336
MOGAS & MPC	381,979
Annual Throughput at Wellhead	393,426

Seasonal Sales Volume @ Burnertip

Jan	73,216
Feb	65,424
Mar	53,242
Apr	37,244
May	20,814
Jun	10,209
Jul	7,438
Aug	7,242
Sep	8,048
Oct	14,772
Nov	29,297
Dec	52,121
<b>TOTAL</b>	<b>379,066</b>

Missouri Public Service  
Division of UtiliCorp United Inc.  
Eastern System  
**Current Gas Cost Calculation**

	<u>Nov-01</u>	<u>Dec-01</u>	<u>Jan-02</u>	<u>Feb-02</u>	<u>Mar-02</u>	<u>Totals</u>
<b>SUMMARY OF COMMODITY COSTS</b>						
Sales Requirements	51,820	100,098	80,283	60,767	46,774	339,742
MoGas/MoPipe Fuel Loss	0.43%	0.43%	0.43%	0.43%	0.43%	
PEPL Market Zone Fuel Loss	1.80%	1.80%	1.80%	1.80%	1.80%	
PEPL Field Zone Fuel Loss	1.13%	1.13%	1.13%	1.13%	1.13%	
Gathering Fuel Loss	<u>0.69%</u>	<u>0.69%</u>	<u>0.69%</u>	<u>0.69%</u>	<u>0.69%</u>	
Total Supply - Fuel Loss	53,976	104,262	83,623	63,295	48,720	353,876
Purchase Requirements	53,976	104,262	83,623	63,295	48,720	
Total Supply	35,976	63,962	43,323	26,895	30,120	200,276
Forecasted Price (NYMEX-PEPL Basis)*	<u>\$ 3.0920</u>	<u>\$ 3.1800</u>	<u>\$ 3.3240</u>	<u>\$ 3.3140</u>	<u>\$ 3.2490</u>	
Total Cost	<u>\$ 111,238</u>	<u>\$ 203,399</u>	<u>\$ 144,006</u>	<u>\$ 89,130</u>	<u>\$ 97,860</u>	<u>\$ 645,633</u>
Contracted Fixed Price Supply	18,000	40,300	40,300	36,400	18,600	
Contracted Price	<u>\$ 4.5550</u>	<u>\$ 4.6142</u>	<u>\$ 4.6142</u>	<u>\$ 4.6142</u>	<u>\$ 4.5550</u>	
Total Cost	<u>\$ 81,990</u>	<u>\$ 185,952</u>	<u>\$ 185,952</u>	<u>\$ 167,957</u>	<u>\$ 84,723</u>	<u>\$ 706,574</u>
<u>Forecasted Gas Commodity Cost</u>	<u>\$ 193,228</u>	<u>\$ 389,351</u>	<u>\$ 329,958</u>	<u>\$ 257,087</u>	<u>\$ 182,583</u>	<u>\$ 1,352,207</u>
<u>Forecasted Sales Gas Quantity</u>	53,976	104,262	83,623	63,295	48,720	353,876
<u>Gas Cost (Commodity) Dth</u>						<u>\$3.8211</u>
<b>SUMMARY OF UPSTREAM COSTS</b>						
Panhandle Eastern Pipeline - Firm						
FT Commodity (Field Zone)	53,603	103,543	83,046	62,858	48,384	
FT Commodity (Market Zone)	<u>52,998</u>	<u>102,373</u>	<u>82,108</u>	<u>62,148</u>	<u>47,837</u>	
Total Units	106,601	205,916	165,154	125,006	96,221	
Cost/Dth Field Zone	<u>\$0.0195</u>	<u>\$0.0195</u>	<u>\$0.0195</u>	<u>\$0.0195</u>	<u>\$0.0195</u>	
Cost/Dth - Market Zone	<u>\$0.0194</u>	<u>\$0.0194</u>	<u>\$0.0194</u>	<u>\$0.0194</u>	<u>\$0.0194</u>	
Total Panhandle Commodity Costs	<u>\$2,073</u>	<u>\$4,005</u>	<u>\$3,212</u>	<u>\$2,431</u>	<u>\$1,872</u>	<u>\$13,594</u>
Missouri Pipeline Company - Firm						
Rolla						
FT Commodity	36,365	70,245	56,340	42,644	32,824	
Salem						
FT Commodity	12,025	23,228	18,629	14,101	10,854	
Owensville						
FT Commodity	<u>3,653</u>	<u>7,057</u>	<u>5,660</u>	<u>4,284</u>	<u>3,298</u>	
Total Units	52,043	100,530	80,629	61,029	46,976	341,207
Cost/Dth - Rolla	<u>\$0.1699</u>	<u>\$0.1699</u>	<u>\$0.1699</u>	<u>\$0.1699</u>	<u>\$0.1699</u>	
Cost/Dth - Salem	<u>\$0.0500</u>	<u>\$0.0500</u>	<u>\$0.0500</u>	<u>\$0.0500</u>	<u>\$0.0500</u>	
Cost/Dth - Owensville	<u>\$0.0500</u>	<u>\$0.0500</u>	<u>\$0.0500</u>	<u>\$0.0500</u>	<u>\$0.0500</u>	
Total MoPipe Commodity Costs	<u>\$6,962</u>	<u>\$13,449</u>	<u>\$10,787</u>	<u>\$8,164</u>	<u>\$6,284</u>	<u>\$45,646</u>
Missouri Gas Company - Firm						
Rolla						
FT Commodity	36,209	69,943	56,098	42,461	32,683	
Salem						
FT Commodity	11,973	23,128	18,549	14,040	10,807	
Owensville						
FT Commodity	<u>3,637</u>	<u>7,026</u>	<u>5,635</u>	<u>4,265</u>	<u>3,283</u>	
Total Units	51,819	100,097	80,282	60,766	46,773	339,739
Cost/Dth - Rolla	<u>\$0.3000</u>	<u>\$0.3000</u>	<u>\$0.3000</u>	<u>\$0.3000</u>	<u>\$0.3000</u>	
Cost/Dth - Salem	<u>\$0.3200</u>	<u>\$0.3200</u>	<u>\$0.3200</u>	<u>\$0.3200</u>	<u>\$0.3200</u>	
Cost/Dth - Owensville	<u>\$0.0800</u>	<u>\$0.0800</u>	<u>\$0.0800</u>	<u>\$0.0800</u>	<u>\$0.0800</u>	
Total MoGas Commodity Costs	<u>\$14,985</u>	<u>\$28,946</u>	<u>\$23,216</u>	<u>\$17,572</u>	<u>\$13,526</u>	<u>\$98,245</u>
Total MoPipe & MoGas Costs	<u>\$21,947</u>	<u>\$42,395</u>	<u>\$34,003</u>	<u>\$25,736</u>	<u>\$19,810</u>	<u>\$143,891</u>
<u>Forecasted Eastern Upstream Costs</u>	<u>\$24,020</u>	<u>\$46,400</u>	<u>\$37,215</u>	<u>\$28,167</u>	<u>\$21,682</u>	<u>\$157,485</u>
<u>Forecasted Firm Sales Quantity</u>	53,976	104,262	83,623	63,295	48,720	353,876
<u>Upstream Cost/Dth</u>						<u>\$0.4450</u>

<b>\$4.2661</b>
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Missouri Public Service  
 Division of UtiliCorp United Inc.  
 Eastern System  
**Gas Commodity Cost Calculation**

INSIDE FERC NOV 01	\$ 3.05
MoGas/MoPipe Fuel Loss	0.43%
PEPL Market Zone Fuel Loss	1.80%
PEPL Field Zone Fuel Loss	1.13%
Gathering Fuel Loss	<u>0.69%</u>

PEPL Index Adjusted for Fuel \$ 3.1769

PEPL Cost/Dth Field Zone	\$0.0195
PEPL Cost/Dth - Market Zone	<u>\$0.0194</u>
Total PEPL Commodity Cost	\$3.2158

PEPL Cost	\$3.2158
MoPipe Cost/Dth - Rolla	\$0.1699
MoGas Cost/Dth - Rolla	<u>\$0.3000</u>
<b>Rolla</b>	<b>\$3.6857</b>

PEPL Cost	\$3.2158
MoPipe Cost/Dth - Salem	\$0.0500
MoGas Cost/Dth - Salem	<u>\$0.3200</u>
<b>Total Salem</b>	<b>\$3.5858</b>

PEPL Cost	\$3.2158
MoPipe Cost/Dth - Owensville	\$0.0500
MoGas Cost/Dth - Owensville	<u>\$0.0800</u>
<b>Total Owensville</b>	<b>\$3.3458</b>

		Percent Split	
Rolla	\$3.6857	69.88%	\$ 2.5754
Salem	\$3.5858	23.11%	\$ 0.8285
Owensville	\$3.3458	7.02%	\$ 0.2349

\$ 3.6388

Total Gas Commodity Costs \$ 3.6388

MISSOURI PUBLIC SERVICE  
SCHEDULE 1 - SPOT MARKET GAS PURCHASES  
BY USAGE MONTH FOR THE SOUTHERN SYSTEM

SUPPLIER	INVOICE NO.	USAGE MONTH	MONTH BOOKED	MMBTU	RATE	COST	OTHER CHARGES	TOTAL SYS. SUPPLY	FIRM PORTION	INTERRUPT. PORTION	STORAGE MMBTU	TOTAL STORAGE	TOTAL MONTH
BASELOAD POOL GAS SYSTEM SUPPLY	VARIOUS	September 2000	October 2000	30,727	4.1203	126,603.41	0.00	126,603.41	126,603.41	0.00	0	0.00	
MPS-KPS TERM POOL GAS SYSTEM SUPPLY	VARIOUS	September 2000	October 2000	25,548	4.5500	116,243.40	0.00	116,243.40	116,243.40	0.00	0	0.00	
KS TERM POOL GAS SYSTEM SUPPLY	VARIOUS	September 2000	October 2000	25,446	4.5000	114,507.00	0.00	114,507.00	114,507.00	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	September 2000	October 2000	2,402	0.0000	32,401.98	0.00	32,401.98	32,401.98	0.00	0	0.00	
WNG SYSTEM SUPPLY TRANS.	1-TNS-0900-07921	September 2000	October 2000	0.0000	236,006.96	0.00	236,006.96	236,006.96	0.00	0	0	93,791.34	
WNG STORAGE TRANS.	1-STO-0900-07921	September 2000	October 2000	0.0000	0.00	0.00	0.00	0.00	0.00	0.00	0	0.00	
WNG CAPACITY RELEASE	1-TNS-0900-07921	September 2000	October 2000	0.0000	(5,712.34)	(5,712.34)	0.00	(5,712.34)	(5,712.34)	0.00	0	0.00	713,841.75
MPS-KPS TERM POOL GAS SYSTEM SUPPLY	VARIOUS	October 2000	November 2000	56,974	5.2400	298,543.76	0.00	298,543.76	298,543.76	0.00	0	0.00	
KS TERM POOL GAS SYSTEM SUPPLY	VARIOUS	October 2000	November 2000	75,402	5.1900	391,336.38	0.00	391,336.38	391,336.38	0.00	0	0.00	
BASELOAD POOL GAS SYSTEM SUPPLY	VARIOUS	October 2000	November 2000	34,171	4.8647	166,233.35	0.00	166,233.35	166,233.35	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	October 2000	November 2000	9,078	7.3988	67,166.22	0.00	67,166.22	67,166.22	0.00	0	0.00	
WNG SYSTEM SUPPLY TRANS.	1-TNS-1000-07921	October 2000	November 2000	0.0000	319,226.17	0.00	319,226.17	319,226.17	0.00	0	0	93,789.82	
WNG STORAGE TRANS.	1-STO-1000-07921	October 2000	November 2000	0.0000	0.00	0.00	0.00	0.00	0.00	0.00	0	0.00	
WNG CAPACITY RELEASE	1-TNS-1000-07921	October 2000	November 2000	0.0000	(5,461.02)	(5,461.02)	0.00	(5,461.02)	(5,461.02)	0.00	0	0.00	1,330,834.68
KS TERM POOL GAS SYSTEM SUPPLY	VARIOUS	November 2000	December 2000	444,148	4.4702	1,985,420.88	0.00	1,985,420.88	1,985,420.88	0.00	0	0.00	
SWNG POOL GAS SYSTEM SUPPLY	VARIOUS	November 2000	December 2000	78,013	5.4727	415,998.34	0.00	415,998.34	415,998.34	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	November 2000	December 2000	(30,330)	5.3857	(163,346.78)	0.00	(163,346.78)	(163,346.78)	0.00	0	0.00	
KS TERM POOL GAS SYSTEM SUPPLY	VARIOUS	November 2000	December 2000	(189,000)	4.4225	(835,852.50)	0.00	(835,852.50)	(835,852.50)	0.00	0	0.00	
WNG SYSTEM SUPPLY TRANS.	1-TNS-1100-07921	November 2000	December 2000	0.0000	0.00	162,000.37	162,000.37	162,000.37	162,000.37	0.00	0	0.00	
ONEOK ENERGY MARKETING TRANS. PPA 1	-2000-11-1139-KGMC	October 2000	December 2000	0.0000	0.00	3,126.90	3,126.90	3,126.90	3,126.90	0.00	0	0.00	
ONEOK ENERGY MARKETING TRANS. PPA 9	-2000-10-1447-KGMC	September 2000	December 2000	0.0000	0.00	3,126.90	3,126.90	3,126.90	3,126.90	0.00	0	0.00	
WNG ASSOC CO STORAGE	1-TNS-1100-07921	November 2000	December 2000	0.0000	0.00	0.00	0.00	0.00	0.00	0.00	229,656	1,045,669.70	
WNG STORAGE TRANS.	1-STO-1100-07921	November 2000	December 2000	0.0000	0.00	0.00	0.00	0.00	0.00	0.00	0	93,791.34	
WNG CAPACITY RELEASE	1-TNS-1100-07921	November 2000	December 2000	0.0000	0.00	(4,918.77)	(4,918.77)	(4,918.77)	(4,918.77)	0.00	0	0.00	2,705,016.38
KS TERM POOL GAS SYSTEM SUPPLY	VARIOUS	December 2000	January 2001	458,954	5.1002	2,340,747.28	0.00	2,340,747.28	2,340,747.28	0.00	0	0.00	
SWNG POOL GAS SYSTEM SUPPLY	VARIOUS	December 2000	January 2001	374,165	9.6851	3,623,837.79	0.00	3,623,837.79	3,623,837.79	0.00	0	0.00	
SWNG POOL GAS SYSTEM SUPPLY - PPA 11	VARIOUS	November 2000	January 2001	848	5.4072	4,585.34	0.00	4,585.34	4,585.34	0.00	0	0.00	
BASELOAD POOL GAS SYSTEM SUPPLY	VARIOUS	December 2000	January 2001	38,568	5.9000	215,751.20	0.00	215,751.20	215,751.20	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	December 2000	January 2001	(52,464)	5.6790	(297,942.24)	0.00	(297,942.24)	(297,942.24)	0.00	0	0.00	
IMBALANCE GAS - PPA 11/00	VARIOUS	November 2000	January 2001	60	4.4300	354.40	0.00	354.40	354.40	0.00	0	0.00	
WNG SYSTEM SUPPLY TRANS.	1-TNS-1200-07921	December 2000	January 2001	0	0.0000	0.00	253,938.91	253,938.91	253,938.91	0.00	0	0.00	
WNG SYSTEM SUPPLY TRANS. - PPA 11/00	1-TNS-1200-07921	December 2000	January 2001	0	0.0000	0.00	19.81	19.81	19.81	0.00	0	0.00	
WNG ASSOC CO STORAGE	1-TNS-1200-07921	December 2000	January 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	176,470	807,686.07	
WNG ASSOC CO STORAGE - PPA 11/00	1-TNS-1100-07921	November 2000	January 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	(907)	(4,129.83)	
WNG STORAGE TRANS.	1-STO-1200-07921	December 2000	January 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	93,791.34	
WNG CAPACITY RELEASE	1-TNS-1200-07921	December 2000	January 2001	0	0.0000	0.00	(24,887.19)	(24,887.19)	(24,887.19)	0.00	0	0.00	
WNG CAPACITY RELEASE - PPA 11/00	1-TNS-1100-07921	November 2000	January 2001	0	0.0000	0.00	(2,087.49)	(2,087.49)	(2,087.49)	0.00	0	0.00	7,011,665.39
TERM POOL GAS SYSTEM SUPPLY	VARIOUS	January 2001	February 2001	454,092	6.8446	3,108,057.71	0.00	3,108,057.71	3,108,057.71	0.00	0	0.00	
SWNG POOL GAS SYSTEM SUPPLY	VARIOUS	January 2001	February 2001	153,904	9.9800	1,535,961.92	0.00	1,535,961.92	1,535,961.92	0.00	0	0.00	
SWNG POOL GAS SYSTEM SUPPLY - PPA 12	VARIOUS	December 2000	February 2001	0	#DIV/0!	278.31	0.00	278.31	278.31	0.00	0	0.00	
BASELOAD POOL GAS SYSTEM SUPPLY	VARIOUS	January 2001	February 2001	112,363	10.5404	1,184,353.31	0.00	1,184,353.31	1,184,353.31	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	January 2001	February 2001	68,996	7.3440	506,710.00	0.00	506,710.00	506,710.00	0.00	0	0.00	
WNG SYSTEM SUPPLY TRANS.	1-TNS-0101-07921	January 2001	February 2001	0	0.0000	0.00	250,973.31	250,973.31	250,973.31	0.00	0	0.00	
WNG ASSOC CO STORAGE - PPA 11/00 & 12/	1-TNS-0101-07921	January 2001	February 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	1	(2.05)	
WNG STORAGE TRANS.	1-STO-0101-07921	January 2001	February 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	91,097.32	
WNG CAPACITY RELEASE	1-TNS-0101-07921	January 2001	February 2001	0	0.0000	0.00	(23,061.26)	(23,061.26)	(23,061.26)	0.00	0	0.00	6,654,368.57
TERM POOL GAS SYSTEM SUPPLY	VARIOUS	February 2001	March 2001	461,184	5.2683	2,429,643.12	0.00	2,429,643.12	2,429,643.12	0.00	0	0.00	
SWNG POOL GAS SYSTEM SUPPLY	VARIOUS	February 2001	March 2001	55,945	6.3034	352,641.21	0.00	352,641.21	352,641.21	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	February 2001	March 2001	(9,216)	16.0675	(148,078.44)	0.00	(148,078.44)	(148,078.44)	0.00	0	0.00	
WNG SYSTEM SUPPLY TRANS.	1-TNS-0201-07921	February 2001	March 2001	0	0.0000	0	244,589.38	244,589.38	244,589.38	0.00	0	0.00	
WNG ASSOC CO STORAGE	1-TNS-1200-07921	February 2001	March 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	158,270	1,100,328.19	
WNG STORAGE TRANS.	1-STO-0201-07921	February 2001	March 2001	0	0.0000	0	0.00	0.00	0.00	0.00	0	91,097.32	
WNG CAPACITY RELEASE	1-TNS-0201-07921	February 2001	March 2001	0	0.0000	0	(16,047.93)	(16,047.93)	(16,047.93)	0.00	0	0.00	4,054,172.85

MISSOURI PUBLIC SERVICE  
SCHEDULE 1 - SPOT MARKET GAS PURCHASES  
BY USAGE MONTH FOR THE SOUTHERN SYSTEM

SUPPLIER	INVOICE NO.	USAGE MONTH	MONTH BOOKED	MMBTU	RATE	COST	OTHER CHARGES	TOTAL SYS. SUPPLY	FIRM PORTION	INTERRUPT. PORTION	STORAGE MMBTU	TOTAL STORAGE	TOTAL MONTH
TERM POOL GAS SYSTEM SUPPLY	VARIOUS	March 2001	April 2001	230,733	4.6448	1,071,702.35	0.00	1,071,702.35	1,071,702.35	0.00			
SWING POOL GAS SYSTEM SUPPLY	VARIOUS	March 2001	April 2001	24,258	5.0968	123,638.11	0.00	123,638.11	123,638.11	0.00			
UCU POOL GAS SYSTEM SUPPLY	VARIOUS	March 2001	April 2001	103,655	5.0300	521,383.53	0.00	521,383.53	521,383.53	0.00			
UCU POOL GAS SYSTEM SUPPLY	VARIOUS	March 2001	April 2001	(103,655)	5.0233	(520,692.50)	0.00	(520,692.50)	(520,692.50)	0.00			
IMBALANCE GAS	VARIOUS	March 2001	April 2001	(1,862)	15.3184	(28,522.90)	0.00	(28,522.90)	(28,522.90)	0.00			
WNG SYSTEM SUPPLY TRANS.	1-TNS-0301-07921	March 2001	April 2001	0	#DIV/0!	0.00	241,928.18	241,928.18	241,928.18	0.00			
WNG ASSOC CO STORAGE	1-TNS-0301-07921	March 2001	April 2001	0	#DIV/0!	0.00	0.00	0.00	0.00	0.00	262,090	1,827,068.97	
WNG STORAGE TRANS.	1-STO-0301-07921	March 2001	April 2001	0	#DIV/0!	0.00	0.00	0.00	0.00	0.00		91,097.32	
WNG CAPACITY RELEASE	1-TNS-0301-07921	March 2001	April 2001	0	0.0000	0.00	(8,485.21)	(8,485.21)	(8,485.21)	0.00			3,319,117.85
BASELOAD POOL GAS SYSTEM SUPPLY	VARIOUS	April 2001	May 2001	172,537	5.2396	904,031.36	0.00	904,031.36	904,031.36	0.00			
IMBALANCE GAS	VARIOUS	April 2001	May 2001	8,565	5.8229	49,873.12	0.00	49,873.12	49,873.12	0.00			
WNG SYSTEM SUPPLY TRANS.	1-TNS-0401-07921	April 2001	May 2001	0	0.0000	0.00	236,721.89	236,721.89	236,721.89	0.00			
WNG ASSOC CO STORAGE	1-TNS-0401-07921	April 2001	May 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00			
WNG STORAGE TRANS.	1-STO-0401-07921	April 2001	May 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00		91,097.32	
WNG CAPACITY RELEASE	1-TNS-0401-07921	April 2001	May 2001	0	0.0000	0.00	(5,082.72)	(5,082.72)	(5,082.72)	0.00			1,297
TERM POOL GAS SYS SUPPLY	VARIOUS	MAY 2001	JUNE 2001	26,949	4.0542	109,257.28		109,257.28	109,257.28	0.00			
BASELOAD POOL GAS SYSTEM SUPPLY	VARIOUS	MAY 2001	JUNE 2001	53,374	4.5996	245,499.29		245,499.29	245,499.29	0.00			
IMBALANCE GAS	VARIOUS	MAY 2001	JUNE 2001	24,436	4.3538	106,389.88		106,389.88	106,389.88	0.00			
WNG SYSTEM SUPPLY TRANS.	1-TNS-0501-07921	MAY 2001	JUNE 2001	0	0.0000	0.00	233,053.08	233,053.08	233,053.08	0.00			
WNG STORAGE TRANS.	1-STO-0501-07921	MAY 2001	JUNE 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00		91,097.32	
WNG CAPACITY RELEASE	1-TNS-0501-07921	MAY 2001	JUNE 2001	0	0.0000	0.00	(8,884.93)	(8,884.93)	(8,884.93)	0.00			776,411.92
TERM POOL GAS SYS SUPPLY	VARIOUS	JUNE 2001	JULY 2001		0.0000			0.00	0.00	0.00			
BASELOAD POOL GAS SYS SUPPLY	VARIOUS	JUNE 2001	JULY 2001	75,740	3.4575	261,874.76		261,874.76	261,874.76	0.00			
SWING POOL GAS SYS SUPPLY	VARIOUS	JUNE 2001	JULY 2001	13,102	3.7867	49,613.31		49,613.31	49,613.31	0.00			
IMBALANCE GAS	VARIOUS	JUNE 2001	JULY 2001	(9,800)	9.1455	(89,625.88)		(89,625.88)	(89,625.88)	0.00			
WNG SYSTEM SUPPLY TRANS.	1-TNS-0601-07921	JUNE 2001	JULY 2001	0	0.0000	0.00	233,927.22	233,927.22	233,927.22	0.00			
WNG STORAGE TRANS.	1-STO-0601-07921	JUNE 2001	JULY 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00		91,097.32	
WNG CAPACITY RELEASE	1-TNS-0601-07921	JUNE 2001	JULY 2001	0	0.0000	0.00	(8,285.59)	(8,285.59)	(8,285.59)	0.00			538,601.14
TERM POOL GAS SYS SUPPLY	VARIOUS	JULY 2001	AUGUST 2001		0.0000			0.00	0.00	0.00			
BASELOAD POOL GAS SYSTEM SUPPLY	VARIOUS	JULY 2001	AUGUST 2001	99,408	2.7850	276,854.45		276,854.45	276,854.45	0.00			
SWING POOL GAS SYS SUPPLY	VARIOUS	JULY 2001	AUGUST 2001	13,565	3.0147	40,893.86		40,893.86	40,893.86	0.00			
IMBALANCE GAS	VARIOUS	JULY 2001	AUGUST 2001	(47,081)	3.5235	(165,888.28)		(165,888.28)	(165,888.28)	0.00			
WNG SYSTEM SUPPLY TRANS.	1-TNS-0701-07921	JULY 2001	AUGUST 2001	0	0.0000	0.00	234,957.21	234,957.21	234,957.21	0.00			
WNG STORAGE TRANS.	1-STO-0701-07921	JULY 2001	AUGUST 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00		91,097.32	
WNG CAPACITY RELEASE	1-TNS-0701-07921	JULY 2001	AUGUST 2001	0	0.0000	0.00	(10,400.19)	(10,400.19)	(10,400.19)	0.00			467,514.37
Billing for Line Hit	VARIOUS	AUGUST 2001	SEPTEMBER 2001		#DIV/0!	(174.22)		(174.22)	(174.22)	0.00			
BASELOAD POOL GAS SYSTEM SUPPLY	VARIOUS	AUGUST 2001	SEPTEMBER 2001	55,581	2.8691	159,467.41		159,467.41	159,467.41	0.00			
IMBALANCE GAS	1-TNS-0801-7921	AUGUST 2001	SEPTEMBER 2001	12,460	0.0000	36,446.18		36,446.18	36,446.18	0.00			
WNG SYSTEM SUPPLY TRANS.	1-STO-0801-07921	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	233,739.37	233,739.37	233,739.37	0.00			
WNG STORAGE TRANS.	1-TNS-0801-07921	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00		91,097.32	
WNG CAPACITY RELEASE	1-TNS-0801-07921	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	(7,040.04)	(7,040.04)	(7,040.04)	0.00			513,536.02
								23,481,158.44	23,481,158.44	-	5,880,563.45	29,361,721.89	

MISSOURI PUBLIC SERVICE  
SCHEDULE 2 - SPOT MARKET GAS PURCHASES  
BY USAGE MONTH FOR THE NORTHERN SYSTEM

SUPPLIER	INVOICE NO.	USAGE MONTH	MONTH BOOKED	MMBTU	RATE	COST	OTHER CHARGES	TOTAL SYS. SUPPLY	FIRM PORTION	INTERRUPT. PORTION	STORAGE MMBTU	TOTAL STORAGE	TOTAL MONTH
WESTERN	139157	September 2000	October 2000	21,025	4.4900	94,402.25	0.00	94,402.25	94,402.25	0.00	0	0.00	
ENRON	16159SA	September 2000	October 2000	9,605	4.4900	43,126.45	0.00	43,126.45	43,126.45	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	September 2000	October 2000	(4,305)	0.0000	0.00	(5,021.76)	(5,021.76)	(5,021.76)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	000900195	September 2000	October 2000	0	0.0000	0.00	109,713.04	109,713.04	109,713.04	0.00	0	0.00	
PEPL STORAGE TRANS.	000900195	September 2000	October 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	55,998.47	
PEPL IN/OUT STORAGE	000900195	September 2000	October 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	
PEPL CAPACITY RELEASE	000900195	September 2000	October 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	298,218.45
EPRIME	200011-1-00064	October 2000	November 2000	10,403	5.1900	53,991.57	0.00	53,991.57	53,991.57	0.00	0	0.00	
TRANSCANADA	40901	October 2000	November 2000	45,247	5.1900	234,831.93	0.00	234,831.93	234,831.93	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	October 2000	November 2000	(5,533)	0.0000	(19,052.07)	0.00	(19,052.07)	(19,052.07)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	00100207	October 2000	November 2000	0	0.0000	0.00	112,639.47	112,639.47	112,639.47	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS. PPA 8/00	000800196	August 2000	November 2000	0	0.0000	0.00	(153.95)	(153.95)	(153.95)	0.00	0	0.00	
PEPL STORAGE TRANS.	00100207	October 2000	November 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	55,998.47	
PEPL IN/OUT STORAGE	00100207	October 2000	November 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	
PEPL CAPACITY RELEASE	00100207	October 2000	November 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	42
IMBALANCE GAS	VARIOUS	November 2000	December 2000	(12,291)	4.9350	(60,656.25)	0.00	(60,656.25)	(60,656.25)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	001100203	November 2000	December 2000	0	#DIV/0!	0.00	127,580.95	127,580.95	127,580.95	0.00	0	0.00	
PEPL ASSOC CO STORAGE-FS	001100203	November 2000	December 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	182,331	706,679.84	
PEPL STORAGE TRANS.	001100203	November 2000	December 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	66,955.92	
PEPL CAPACITY RELEASE	001100203	November 2000	December 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	840,560.46
WESTERN GAS RESOURCES	140338	December 2000	January 2001	58,414	5.8750	343,182.25	0.00	343,182.25	343,182.25	0.00	0	0.00	
TRANSCANADA	43048	December 2000	January 2001	19,324	10.4326	201,599.64	0.00	201,599.64	201,599.64	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	December 2000	January 2001	(3,079)	7.7983	(24,010.98)	0.00	(24,010.98)	(24,010.98)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	001200204	December 2000	January 2001	0	0.0000	0.00	129,498.83	129,498.83	129,498.83	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.-PPA 11/00	001100203	November 2000	January 2001	0	0.0000	0.00	(21.13)	(21.13)	(21.13)	0.00	0	0.00	
PEPL ASSOC CO STORAGE-FS	001200204	December 2000	January 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	257,928	1,001,780.50	
PEPL ASSOC CO STORAGE-FS PPA 11/00	001100203	December 2000	January 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	18.28	
PEPL STORAGE TRANS.	001200204	December 2000	January 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	66,955.92	
PEPL CAPACITY RELEASE	001200204	December 2000	January 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	1,719,003.31
ANADARKO	A0102S0067	January 2001	February 2001	100,000	9.9775	997,750.00	0.00	997,750.00	997,750.00	0.00	0	0.00	
TRANSCANADA	44131	January 2001	February 2001	8,000	9.3000	55,800.00	0.00	55,800.00	55,800.00	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	January 2001	February 2001	3,079	0.6079	1,871.80	0.00	1,871.80	1,871.80	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	010100202	January 2001	February 2001	0	0.0000	0.00	128,928.00	128,928.00	128,928.00	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.-PPA 11/00	001100203	November 2000	February 2001	0	0.0000	0.00	(1,479.86)	(1,479.86)	(1,479.86)	0.00	0	0.00	
PEPL ASSOC CO STORAGE-FS	010100202	January 2001	February 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	156,191	606,646.75	
PEPL STORAGE TRANS.	010100202	January 2001	February 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	66,955.92	
PEPL CAPACITY RELEASE	010100202	January 2001	February 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	1,856,472.61
TPC	TPSCI12001020182	February 2001	March 2001	105,000	6.2175	652,837.50	0.00	652,837.50	652,837.50	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	February 2001	March 2001	8	1,864.55	14,916.36	0.00	14,916.36	14,916.36	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	010200202	February 2001	March 2001	0	0.0000	0.00	123,415.25	123,415.25	123,415.25	0.00	0	0.00	
PEPL ASSOC CO STORAGE-FS	010200202	February 2001	March 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	131,527	515,994.36	
PEPL STORAGE TRANS.	010200202	February 2001	March 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	66,955.92	
PEPL CAPACITY RELEASE	010200202	February 2001	March 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	1,374,119.39

MISSOURI PUBLIC SERVICE  
SCHEDULE 2 - SPOT MARKET GAS PURCHASES  
BY USAGE MONTH FOR THE NORTHERN SYSTEM

SUPPLIER	INVOICE NO.	USAGE MONTH	MONTH BOOKED	MMBTU	RATE	COST	OTHER CHARGES	TOTAL SYS. SUPPLY	FIRM PORTION	INTERRUPT. PORTION	STORAGE MMBTU	TOTAL STORAGE	TOTAL MONTH
ANADARKO	A0104S0067	March 2001	April 2001	18,689	5.1248	95,774.06	0.00	95,774.06	95,774.06	0.00			
WESTERN	141812	March 2001	April 2001	49,121	5.1154	251,271.81	0.00	251,271.81	251,271.81	0.00			
TRANSCANADA	46114	March 2001	April 2001	91,000	5.0000	455,000.00	0.00	455,000.00	455,000.00	0.00			
IMBALANCE GAS	VARIOUS	March 2001	April 2001	4,454	6.0994	27,186.64	0.00	27,186.64	27,186.64	0.00			
PEPL SYSTEM SUPPLY TRANS.	010300215	March 2001	April 2001	0	0.0000	0.00	133,502.64	133,502.64	133,502.64	0.00			
PEPL ASSOC CO STORAGE-FS	010300215	March 2001	April 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	30,259	144,012.92	
PEPL STORAGE TRANS.	010300215	March 2001	April 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00		66,955.92	
PEPL CAPACITY RELEASE	010300215	March 2001	April 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00			1,173,683.99
ANADARKO	A0105S0069	April 2001	May 2001	42,901	5.3075	227,697.06	0.00	227,697.06	227,697.06	0.00			
TRANSCANADA	46885	April 2001	May 2001	7,578	5.0157	38,008.77	0.00	38,008.77	38,008.77	0.00			
TENASKA	200104-0093	April 2001	May 2001	5,000	5.2750	26,375.00	0.00	26,375.00	26,375.00	0.00			
HELMERICH AND PAYNE	S-6044	April 2001	May 2001	2,078	5.3075	11,028.99	0.00	11,028.99	11,028.99	0.00			
IMBALANCE GAS	VARIOUS	April 2001	May 2001	17	13.1453	223.47	0.00	223.47	223.47	0.00			
PEPL SYSTEM SUPPLY TRANS.	010400219	April 2001	May 2001	0	0.0000	0.00	87,101.01	87,101.01	87,101.01	0.00			
REGULATED SFR MARGIN	VARIOUS	April 2001	May 2001	0	0.0000	0.00	34.25	34.25	34.25	0.00			
PEPL STORAGE TRANS.		April 2001	May 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00		55,998.47	
PEPL CAPACITY RELEASE		April 2001	May 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00			446,467.02
El Paso	S-39747	MAY 2001	JUNE 2001	29,258	4.8100	140,730.98		140,730.98	140,730.98	0.00			
IMBALANCE GAS	VARIOUS	MAY 2001	JUNE 2001	(1)	230.71	(230.71)		(230.71)	(230.71)	0.00			
PEPL SYSTEM SUPPLY TRANS.	010500220	MAY 2001	JUNE 2001	0.0000			89,132.06	89,132.06	89,132.06	0.00			
PEPL SYSTEM SUPPLY TRANS. PPA - 04/00		MAY 2001	JUNE 2001	0.0000				0.00	0.00	0.00			
PEPL ASSOC CO STORAGE-FS		MAY 2001	JUNE 2001	0.0000				0.00	0.00	0.00	2,126	10,953.34	
PEPL STORAGE TRANS.		MAY 2001	JUNE 2001	0.0000				0.00	0.00	0.00		55,998.47	
PEPL IN/OUT STORAGE		MAY 2001	JUNE 2001	0.0000				0.00	0.00	0.00			
PEPL CAPACITY RELEASE PPA - 04/00		MAY 2001	JUNE 2001	0.0000				0.00	0.00	0.00			
PEPL CAPACITY RELEASE		MAY 2001	JUNE 2001	0.0000				0.00	0.00	0.00			296,584.14
Tenaska	200106-0134	JUNE 2001	JULY 2001	3,175	4.680	14,859.00		14,859.00	14,859.00	0.00			
IMBALANCE GAS	VARIOUS	JUNE 2001	JULY 2001	(31)	21.011	(651.35)		(651.35)	(651.35)	0.00			
Energy USA	TPCS12001060115	JUNE 2001	JULY 2001	22,309	4.1700	93,028.53		93,028.53	93,028.53	0.00			
WESTERN	142922	JUNE 2001	JULY 2001	3,800	3.6150	13,737.00		13,737.00	13,737.00	0.00			
PEPL SYSTEM SUPPLY TRANS.	010600215	JUNE 2001	JULY 2001				86,283.97	86,283.97	86,283.97	0.00			55,998.47
PEPL ASSOC CO STORAGE-IOS		JUNE 2001	JULY 2001				0.0000	0.00	0.00	0.00			
PEPL STORAGE TRANS.		JUNE 2001	JULY 2001				0.0000	0.00	0.00	0.00			
PEPL STORAGE TRANS. PPA - 05/00		JUNE 2001	JULY 2001				0.0000	0.00	0.00	0.00			
PEPL IN/OUT STORAGE		JUNE 2001	JULY 2001				0.0000	0.00	0.00	0.00			
PEPL CAPACITY RELEASE		JUNE 2001	JULY 2001				0.0000	0.00	0.00	0.00			283,255.62
TENASKA	200107-0119	JULY 2001	AUGUST 2001	5,811	4.6800	26,259.48		26,259.48	26,259.48	0.00			
IMBALANCE GAS	VARIOUS	JULY 2001	AUGUST 2001	1	(254.35)	(254.35)		(254.35)	(254.35)	0.00			
Energy USA	TPCS12001070158	JULY 2001	AUGUST 2001	13,815	4.1700	57,808.55		57,808.55	57,808.55	0.00	0		
WESTERN	143430	JULY 2001	AUGUST 2001	210	3.0200	634.20		634.20	634.20	0.00			
PEPL SYSTEM SUPPLY TRANS.	010700206	JULY 2001	AUGUST 2001				98,366.60	98,366.60	98,366.60	0.00	0		
PEPL ASSOC CO STORAGE-IOS		JULY 2001	AUGUST 2001				0.0000	0.00	0.00	0.00	0		
PEPL STORAGE TRANS.		JULY 2001	AUGUST 2001				0.0000	0.00	0.00	0.00	0	55,998.47	
PEPL SYSTEM SUPPLY TRANS. PPA - 06/0	010700206	JULY 2001	AUGUST 2001				12,360.00	12,360.00	12,360.00	0.00			
PEPL SYSTEM SUPPLY TRANS. PPA - 05/0	010700206	JULY 2001	AUGUST 2001				9,512.00	9,512.00	9,512.00	0.00			
PEPL SYSTEM SUPPLY TRANS. PPA - 04/0	010700206	JULY 2001	AUGUST 2001				12,560.04	12,560.04	12,560.04	0.00			
PEPL SYSTEM SUPPLY TRANS. PPA - 03/0	010700206	JULY 2001	AUGUST 2001				9,712.00	9,712.00	9,712.00	0.00			
PEPL SYSTEM SUPPLY TRANS. PPA - 02/0	010700206	JULY 2001	AUGUST 2001				18,256.04	18,256.04	18,256.04	0.00			
PEPL SYSTEM SUPPLY TRANS. PPA - 01/0	010700206	JULY 2001	AUGUST 2001				9,712.00	9,712.00	9,712.00	0.00			
PEPL SYSTEM SUPPLY TRANS. PPA - 12/0	010700206	JULY 2001	AUGUST 2001				0.0000	0.00	0.00	0.00	0		
PEPL SYSTEM SUPPLY TRANS. PPA - 11/0	010700206	JULY 2001	AUGUST 2001				12,560.04	12,560.04	12,560.04	0.00	0		
PEPL IN/OUT STORAGE	000700208	JULY 2001	AUGUST 2001				0.0000	0.00	0.00	0.00	0		
PEPL CAPACITY RELEASE	000700208	JULY 2001	AUGUST 2001				0.0000	0.00	0.00	0.00	0		332,997.07
TENASKA	200108-0198	AUGUST 2001	SEPTEMBER 2001	449	4.6800	2,101.32		2,101.32	2,101.32	0.00	0		
Energy USA	TPCS12001080135	AUGUST 2001	SEPTEMBER 2001	29,004	4.1700	120,946.68		120,946.68	120,946.68	0.00	0		
IMBALANCE GAS	VARIOUS	AUGUST 2001	SEPTEMBER 2001	6	5.2300	31.38		31.38	31.38	0.00	0		
Billing for line loss		AUGUST 2001	SEPTEMBER 2001			(18,778.55)		(18,778.55)	(18,778.55)	0.00	0		
PEPL SYSTEM SUPPLY TRANS.	010800207	AUGUST 2001	SEPTEMBER 2001				98,649.93	98,649.93	98,649.93	0.00	0		
PEPL SYSTEM SUPPLY TRANS. PPA - 04/00		AUGUST 2001	SEPTEMBER 2001				0.0000	0.00	0.00	0.00	0		
PEPL STORAGE TRANS.	010800209	AUGUST 2001	SEPTEMBER 2001				0.0000	0.00	0.00	0.00	0	55,998.47	
PEPL IN/OUT STORAGE	000800196	AUGUST 2001	SEPTEMBER 2001				0.0000	0.00	0.00	0.00	0		
PEPL CAPACITY RELEASE	000800196	AUGUST 2000	SEPTEMBER 2001				0.0000	0.00	0.00	0.00	0		258,949.23
				681,341.00		4,173,158.41	1,412,553.42	5,585,711.83	5,585,711.83	0.00	760,362	3,712,854.98	9,298,566.71

**MISSOURI PUBLIC SERVICE  
SCHEDULE 3 - SPOT MARKET GAS PURCHASES  
BY USAGE MONTH FOR THE EASTERN SYSTEM**

SUPPLIER	INVOICE NO.	USAGE MONTH	MONTH BOOKED	MMBTU	RATE	COST	OTHER CHARGES	TOTAL SYS. SUPPLY	FIRM PORTION	INTERRUPT. PORTION	STORAGE MMBTU	TOTAL STORAGE	TOTAL MONTH
TRANSCANADA	46114	March 2001	April 2001	57,000	5.0000	285,000.00	0.00	285,000.00	285,000.00	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	March 2001	April 2001			(8,793)	6.3327	(55,683.45)	(55,683.45)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	010300215	March 2001	April 2001	0	0.0000	0.00	56,593.59	56,593.59	56,593.59	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT03,2001	March 2001	April 2001	0	0.0000	0.00	66,862.12	66,862.12	66,862.12	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT103,2001	March 2001	April 2001	0	0.0000	0.00	22,161.82	22,161.82	22,161.82	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens03,2001	March 2001	April 2001	0	0.0000	0.00	15,620.16	15,620.16	15,620.16	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOWens03,2001	March 2001	April 2001	0	0.0000	0.00	1,212.60	1,212.60	1,212.60	0.00	0	0.00	
PEPL CAPACITY RELEASE	010300215	March 2001	April 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	391,766.84
ANADARKO	A0105S0069	April 2001	May 2001	24,750	5.3075	131,360.62	0.00	131,360.62	131,360.62	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	April 2001	May 2001			(5,131)	5.2621	(26,999.91)	(26,999.91)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	010400219	April 2001	May 2001	0	0.0000	0.00	55,487.74	55,487.74	55,487.74	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT04,2001	April 2001	May 2001	0	0.0000	0.00	57,282.46	57,282.46	57,282.46	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens04,2001	April 2001	May 2001	0	0.0000	0.00	15,325.76	15,325.76	15,325.76	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOWen04,2001	April 2001	May 2001	0	0.0000	0.00	1,028.60	1,028.60	1,028.60	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT104,2001	April 2001	May 2001	0	0.0000	0.00	17,725.07	17,725.07	17,725.07	0.00	0	0.00	
PEPL CAPACITY RELEASE	010400219	April 2001	May 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	251,210.34
EL PASO	S-39747	MAY 2001	JUNE 2001	8,587	4.8100	41,303.47		41,303.47	41,303.47	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	MAY 2001	JUNE 2001	4,261	5.3159	22,650.90		22,650.90	22,650.90	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	000500209	MAY 2001	JUNE 2001	0	0.0000	0.00	3,100.00	3,100.00	3,100.00	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT5,2001	MAY 2001	JUNE 2001	0	0.0000	0.00	55,536.78	55,536.78	55,536.78	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS. - PPA	NGUT105,2001	MAY 2001	JUNE 2001	0	0.0000	0.00		0.00	0.00	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT105,2001	MAY 2001	JUNE 2001	0	0.0000	0.00	16,911.49	16,911.49	16,911.49	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens05,2001	MAY 2001	JUNE 2001	0	0.0000	0.00	15,282.80	15,282.80	15,282.80	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOWens05,2001	MAY 2001	JUNE 2001	0	0.0000	0.00	1,001.75	1,001.75	1,001.75	0.00	0	0.00	
PEPL CAPACITY RELEASE	000500209	MAY 2001	JUNE 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	155,787.19
WESTERN	142922	JUNE 2001	JULY 2001	12,240	3.6150	44,247.60		44,247.60	44,247.60	0.00	0	0.00	
IMBALANCE	VARIOUS	JUNE 2001	JULY 2001			(978)	3.5890	(3,510.03)	(3,510.03)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	estimate	JUNE 2001	JULY 2001	0	0.0000	0.00	4,470.00	4,470.00	4,470.00	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT06,2001	JUNE 2001	JULY 2001	0	0.0000	0.00	16,720.17	16,720.17	16,720.17	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NGUT106,2001	JUNE 2001	JULY 2001	0	0.0000	0.00	55,068.96	55,068.96	55,068.96	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens06,2001	JUNE 2001	JULY 2001	0	0.0000	0.00	15,267.84	15,267.84	15,267.84	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOWens06,2001	JUNE 2001	JULY 2001	0	0.0000	0.00	992.40	992.40	992.40	0.00	0	0.00	
PEPL CAPACITY RELEASE		JUNE 2001	JULY 2001	0	0.0000	0.00		0.00	0.00	0.00	0	0.00	133,256.94
WESTERN	143430	JULY 2001	AUGUST 2001	8,586	3.0200	25,929.72		25,929.72	25,929.72	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	JULY 2001	AUGUST 2001			(1,620)	2.6689	(4,323.60)	(4,323.60)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	010700206	JULY 2001	AUGUST 2001	0	0.0000	0.00	3,134.79	3,134.79	3,134.79	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT07,2001	JULY 2001	AUGUST 2001	0	0.0000	0.00	53,881.22	53,881.22	53,881.22	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT107,2001	JULY 2001	AUGUST 2001	0	0.0000	0.00	16,067.46	16,067.46	16,067.46	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens07,2001	JULY 2001	AUGUST 2001	0	0.0000	0.00	15,248.80	15,248.80	15,248.80	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	Nowens07,2001	JULY 2001	AUGUST 2001	0	0.0000	0.00	980.50	980.50	980.50	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS. 4/01 ppa	010700206	JULY 2001	AUGUST 2001	0	0.0000	0.00	(46,446.92)	(46,446.92)	(46,446.92)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS 5/01 ppa.	010700206	JULY 2001	AUGUST 2001	0	0.0000	0.00	40.43	40.43	40.43	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS. 6/01 ppa	010700206	JULY 2001	AUGUST 2001	0	0.0000	0.00	0.17	0.17	0.17	0.00	0	0.00	64,512.57
WESTERN	143814	AUGUST 2001	SEPTEMBER 2001	6,355	3.0425	19,335.09		19,335.09	19,335.09	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	AUGUST 2001	SEPTEMBER 2001			(57)	4.4742	(255.03)	(255.03)	0.00	0	0.00	
BILLING FOR LINE LOSS		AUGUST 2002	SEPTEMBER 2002					(1.95)	(1.95)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	010800208	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	2,328.24	2,328.24	2,328.24	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.-PPA 07/00		AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00		0.00	0.00	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT08,2001	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	53,726.00	53,726.00	53,726.00	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT108,2001	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	15,976.40	15,976.40	15,976.40	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens08,2001	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	15,243.76	15,243.76	15,243.76	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOWens08,2001	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	977.35	977.35	977.35	0.00	0	0.00	
PEPL CAPACITY RELEASE	000800196	AUGUST 2001	SEPTEMBER 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	107,327.86
				428,658		2,765,157.90	1,554,484.04	4,236,735.96	4,236,735.96	0.00	0.00	0.00	4,236,735.96

**MISSOURI PUBLIC SERVICE  
SCHEDULE 3 - SPOT MARKET GAS PURCHASES  
BY USAGE MONTH FOR THE EASTERN SYSTEM**

SUPPLIER	INVOICE NO.	USAGE MONTH	MONTH BOOKED	MMBTU	RATE	COST	OTHER CHARGES	TOTAL SYS. SUPPLY	FIRM PORTION	INTERRUPT. PORTION	STORAGE MMBTU	TOTAL STORAGE	TOTAL MONTH
IMBALANCE GAS	VARIOUS	SEPTEMBER 2000	OCTOBER 2000	1,994	0.0000	13,060.27	0.00	13,060.27	13,060.27	0.00	0	0.00	
ENRON	16159SA	September 2000	October 2000	190	4.4900	853.10	0.00	853.10	853.10	0.00	0	0.00	
WESTERN	139157	September 2000	October 2000	5,510	4.4900	24,739.90	0.00	24,739.90	24,739.90	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	000900195	September 2000	October 2000	0	0.0000	0.00	2,128.04	2,128.04	2,128.04	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT09,2000	September 2000	October 2000	0	0.0000	0.00	50,078.57	50,078.57	50,078.57	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT109,2000	September 2000	October 2000	0	0.0000	0.00	14,461.36	14,461.36	14,461.36	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens09,2000	September 2000	October 2000	0	0.0000	0.00	15,254.16	15,254.16	15,254.16	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOwens09,2000	September 2000	October 2000	0	0.0000	0.00	983.85	983.85	983.85	0.00	0	0.00	
PEPL CAPACITY RELEASE	000900195	September 2000	October 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	121,559.25
							82,905.98						
TPC	TPCSI2000100160	October 2000	November 2000	15,500	5.1900	80,445.00	0.00	80,445.00	80,445.00	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	October 2000	November 2000	(219)	0.0000	3,898.49	0.00	3,898.49	3,898.49	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	00100207	October 2000	November 2000	0	0.0000	0.00	5,851.27	5,851.27	5,851.27	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT10,2000	October 2000	November 2000	0	0.0000	0.00	51,671.30	51,671.30	51,671.30	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT110,2000	October 2000	November 2000	0	0.0000	0.00	15,401.08	15,401.08	15,401.08	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens10,2000	October 2000	November 2000	0	0.0000	0.00	15,316.48	15,316.48	15,316.48	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOwens10,2000	October 2000	November 2000	0	0.0000	0.00	1,022.80	1,022.80	1,022.80	0.00	0	0.00	
PEPL CAPACITY RELEASE	00100207	October 2000	November 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	173,606.42
ANADARKO	A0012S0061	November 2000	December 2000	46,504	4.4100	205,082.64	0.00	205,082.64	205,082.64	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	November 2000	December 2000	6,490	0.0000	23,181.18	0.00	23,181.18	23,181.18	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	001100203	November 2000	December 2000	0	0.0000	0.00	55,111.61	55,111.61	55,111.61	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT11,2000	November 2000	December 2000	0	0.0000	0.00	59,678.59	59,678.59	59,678.59	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT111,2000	November 2000	December 2000	0	0.0000	0.00	20,100.78	20,100.78	20,100.78	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens11,2000	November 2000	December 2000	0	0.0000	0.00	15,625.20	15,625.20	15,625.20	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOwens11,2000	November 2000	December 2000	0	0.0000	0.00	1,215.75	1,215.75	1,215.75	0.00	0	0.00	
PEPL CAPACITY RELEASE	001100203	November 2000	December 2000	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	379,995.75
WESTERN GAS RESOURCES	140338	December 2000	January 2001	81,165	5.8750	476,844.38	0.00	476,844.38	476,844.38	0.00	0	0.00	
TRANSCANADA	43048	December 2000	January 2001	2,676	9.4433	25,270.36	0.00	25,270.36	25,270.36	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	December 2000	January 2001	18,374	6.9572	127,831.20	0.00	127,831.20	127,831.20	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	001200204	December 2000	January 2001	0	0.0000	0.00	57,735.18	57,735.18	57,735.18	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT12,2000	December 2000	January 2001	0	0.0000	0.00	71,484.27	71,484.27	71,484.27	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT112,2000	December 2000	January 2001	0	0.0000	0.00	27,251.92	27,251.92	27,251.92	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens12,2000	December 2000	January 2001	0	0.0000	0.00	16,052.24	16,052.24	16,052.24	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOwens12,2000	December 2000	January 2001	0	0.0000	0.00	1,482.65	1,482.65	1,482.65	0.00	0	0.00	
PEPL CAPACITY RELEASE	001200204	December 2000	January 2001	0	0.0000	0.00	0.00	0.00	0.00	0.00	0	0.00	803,952.20
ANADARKO	A0102S0067	January 2001	February 2001	101,500	9.9775	1,012,716.25	0.00	1,012,716.25	1,012,716.25	0.00	0	0.00	
TRANSCANADA	44131	January 2001	February 2001	3,000	9.3000	27,900.00	0.00	27,900.00	27,900.00	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	January 2001	February 2001	(21,589)	3.9621	(85,537.36)	0.00	(85,537.36)	(85,537.36)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	010100202	January 2001	February 2001	0	0.0000	0	58,298.22	58,298.22	58,298.22	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT 01,2001	January 2001	February 2001	0	0.0000	0	86,381.62	86,381.62	86,381.62	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT1 01,2001	January 2001	February 2001	0	0.0000	0	26,570.13	26,570.13	26,570.13	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	Ngowens 01,2001	January 2001	February 2001	0	0.0000	0	15,863.92	15,863.92	15,863.92	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOwens 01,2001	January 2001	February 2001	0	0.0000	0	1,364.95	1,364.95	1,364.95	0.00	0	0.00	
PEPL CAPACITY RELEASE	000100213	January 2001	February 2001	0	0.0000	0	0.00	0.00	0.00	0.00	0	0.00	1,143,557.73
TPC	TPSCH2001020182	February 2001	March 2001	63,000	6.2175	391,702.50	0.00	391,702.50	391,702.50	0.00	0	0.00	
IMBALANCE GAS	VARIOUS	February 2001	March 2001	(637)	65.7511	(41,883.44)	0.00	(41,883.44)	(41,883.44)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.	010200202	February 2001	March 2001	0	0.0000	0	51,934.85	51,934.85	51,934.85	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.-PPA 11/00	001100203	November 2000	March 2001	0	0.0000	0	(121.88)	(121.88)	(121.88)	0.00	0	0.00	
PEPL SYSTEM SUPPLY TRANS.-PPA 12/00	001200204	December 2000	March 2001	0	0.0000	0	203.84	203.84	203.84	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGUT02,2001	February 2001	March 2001	0	0.0000	0	68,492.36	68,492.36	68,492.36	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NUT102,2001	February 2001	March 2001	0	0.0000	0	22,886.01	22,886.01	22,886.01	0.00	0	0.00	
MOGAS SYSTEM SUPPLY TRANS.	NGowens02,2001	February 2001	March 2001	0	0.0000	0	15,716.08	15,716.08	15,716.08	0.00	0	0.00	
MOPIPE SYSTEM SUPPLY TRANS.	NOwens02,2001	February 2001	March 2001	0	0.0000	0	1,272.55	1,272.55	1,272.55	0.00	0	0.00	
PEPL CAPACITY RELEASE	010200202	February 2001	March 2001	0	0.0000	0	0.00	0.00	0.00	0.00	0	0.00	510,202.87

**MISSOURI PUBLIC SERVICE  
SCHEDULE 4 - CALCULATION OF  
NEW RECOVERY BALANCE  
2000-2001 ACA YEAR**

Line	SOUTHERN SYSTEM		NORTHERN SYSTEM		EASTERN SYSTEM		TOTAL	Line	
	FIRM	INTERRUPT.	FIRM	INTERRUPT.	FIRM	INTERRUPT.			
1	ACA RECOVERY	1,232,844.39	0.00	682,290.25	0.00	360,529.24	0.00	2,275,663.88	1
2	REGULAR RECOVERY	23,081,181.70	0.00	8,549,978.19	0.00	3,387,831.10	0.00	35,018,990.99	2
3	TOTAL RECOVERY	24,314,026.09	0.00	9,232,268.44	0.00	3,748,360.34	0.00	37,294,654.87	3
	LESS:								
4	PURCHASED GAS COST PER BOOKS	23,481,158.44	0.00	5,585,711.83	0.00	4,236,735.96	0.00	33,303,606.23	4
5	STORAGE COSTS	5,880,563.45	0.00	3,712,854.88	0.00	0.00	0.00	9,593,418.33	5
6	TOTAL PURCHASED GAS COST PER BOOKS	29,361,721.89	0.00	9,298,566.71	0.00	4,236,735.96	0.00	42,897,024.56	6
7	GROSS RECOVERY	(5,047,695.80)	0.00	(66,298.27)	0.00	(488,375.62)	0.00	(5,602,369.69)	7
8	DCCB INTEREST REFUNDED (COLLECTED) 1999-2000 ACA YEAR	0.00	0.00		0.00		0.00	0.00	
9	PRIOR PERIOD ADJ DCCB INTEREST 1998-1999 ACA YEAR	0.00	0.00	0.00	0.00		0.00	0.00	
10	GO-2001-249 ADJUSTMENT - BOOKED 1/31/01	38,964.87	0.00	0.00	0.00	9,734.51	0.00	48,699.38	10
11	ACA YEAR TRANSPORTATION COST ADJUSTMENT	0.00	0.00		0.00	0.00	0.00	0.00	11
12	REV. RECOVERY OVER/(UNDER) COST	(5,008,730.93)	0.00	(66,298.27)	0.00	(478,641.11)	0.00	(5,553,670.31)	12
13	BEGINNING ACA RECOVERY BALANCE SEPTEMBER 2000	(999,472.71)	9,563.19	(695,964.90)	(104,100.46)	(872,698.98)	0.00	(2,662,673.86)	13
14	ACA RECOVERY BALANCE August 2001 PER BOOKS	(5,952,985.79)	9,563.19	(757,452.31)	(104,100.46)	(1,341,793.27)	0.00	(8,146,768.64)	14
15	LESS ACTUAL ACA RECOVERY 09/01 BOOKED 08/01	(55,217.85)	0.00	(18,312.66)	0.00	(9,546.89)	0.00	(83,077.40)	15
16	DCCB INTEREST ADJ FOR 2000-2001	(109,760.00)	0.00	(12,442.00)	0.00	(33,607.00)	0.00	(155,809.00)	16
17	ADJUSTMENTS	0.00	0.00	13,502.18	0.00		0.00	13,502.18	17
18	ADJUSTMENTS for 3 yr Recovery Proposal					290,899.66		290,899.66	18
19	ENDING ACA RECOVERY BALANCE PER BOOKS	(6,117,963.64)	9,563.19	(774,704.79)	(104,100.46)	(1,094,047.50)	0.00	(8,081,253.20)	19
20	GR-93-172 MCF SALES	3,823,123	123,143	1,468,777	0	379,066	0	5,794,109	20
21	CALCULATED ACA RATES FOR 11/19/01 PER CCF	0.16003	(0.00777)	0.05274	0.00000	0.28862	0.00000		21
22	EFFECTIVE 11/21/00	(0.04165)	(0.00777)	(0.05138)	0.00000	0.05975	0.00000		22
23	CHANGE IN ACA RATE	0.20168	0.00000	0.10412	0.00000	0.22887	0.00000		23

# Enclosure 5

## MISSOURI PUBLIC SERVICE Southern System Gas Refund

		FIRM	INTERRUPTIBLE	TOTAL
1	<b>Beginning Balance September 2000</b>	<b>\$228,692.78</b>	<b>\$0.00</b>	<b>\$228,692.78</b>
2	<b>Actual Refund to Customers by Month</b>			
3	September 2000	\$46,878.12	\$0.00	\$46,878.12
4	October 2000	\$76,924.96	\$0.00	\$76,924.96
5	November 2000      2000	\$131,023.68	\$0.00	\$131,023.68
6	December 2000	\$98,923.72	\$0.00	\$98,923.72
7	January 2001	\$54,481.17	\$0.00	\$54,481.17
8	February 2001	\$39,633.01	\$0.00	\$39,633.01
9	March 2001	\$34,899.73	\$0.00	\$34,899.73
10	April 2001	\$20,398.27	\$0.00	\$20,398.27
11	May 2001	\$7,561.22	\$0.00	\$7,561.22
12	June 2001	\$6,080.46	\$0.00	\$6,080.46
13	July 2001	\$4,746.74	\$0.00	\$4,746.74
14	August 2001	\$4,224.60	\$0.00	\$4,224.60
15	<b>TOTAL:</b>	<b>\$525,775.68</b>	<b>\$0.00</b>	<b>\$525,775.68</b>
16	<b>(Over)/Under Refund</b>	<b>(\$297,082.90)</b>	<b>\$0.00</b>	<b>(\$297,082.90)</b>
17	<b>Supplier Refunds Sep-00 to Aug-01</b>			
	Williams Refund Check #500142    Jan-01	\$38,053.77	\$0.00	\$38,053.77
	6% Interest (1/26/01 - 5/1/01)	\$600.52	\$0.00	\$600.52
	6% Interest (5/2/01 - 11/01/01)	\$1,151.00	\$0.00	\$1,151.00
	Williams Refund Check #500277    Feb-01	\$22,723.01	\$0.00	\$22,723.01
	6% Interest (2/23/01 - 5/1/01)	\$254.00	\$0.00	\$254.00
	6% Interest (5/2/01 - 11/01/01)	\$687.29	\$0.00	\$687.29
			\$0.00	\$0.00
			\$0.00	\$0.00
			\$0.00	\$0.00
	<b>TOTAL:</b>	<b>\$63,469.59</b>	<b>\$0.00</b>	<b>\$63,469.59</b>
	<b>Balance as of August 31, 2001</b>	<b>(\$233,613.31)</b>	<b>\$0.00</b>	<b>(\$233,613.31)</b>
	<b>Annual Firm Mcf Sales Per GR-93-172:</b>			<b>3,823,123</b>
	<b>Refund Rate Per Ccf:</b>			<b>\$ (0.00611)</b>

MPS proposes to change the refund rate from the present rate of \$0.0598/Mcf to (.0611)/Mcf.



Utilicorp United Inc.  
 Attn: Diane Michalski  
 7101 Mercy Road - Suite 400  
 Omaha, NE 68165

NO. 500277

007397 002 UTILICORP UNITED INC 02/23/01 500277

INVOICE NUMBER	DATE	VOUCHER NO.	P.O./ CONTRACT NO.	GROSS	DISCOUNT	NET
02222001	02/22/01	347821		40,207.00	0.00	40,207.00
WEBB STORAGE REFUND IN01-2-000						
*TOTAL*				40,207.00	0.00	40,207.00

DETACH THIS STATEMENT AND RETAIN FOR YOUR FILES

THIS MULTITONE AREA OF THE DOCUMENT CHANGES COLOR GRADUALLY AND EVENLY FROM DARK TO LIGHT WITH DARKER AREAS BOTH TOP AND BOTTOM

P. O. BOX 20008  
 Owensboro, Kentucky 42304  
 (270) 926-8686

NO. 500277

DATE	AMOUNT
02/23/01	*****\$40,207.00

WILLIAMS GAS PIPELINES CENTRAL, INC.

PAY TO THE ORDER OF UTILICORP UNITED INC  
 ATTN: ROBERT EADS  
 20 WEST 9TH STREET 7-263  
 KANSAS CITY MO 64105

BY: *Rich A. Baile*  
 Vice President

BY: \_\_\_\_\_

BankBoston Maine, N.A.  
 SOUTH PORTLAND, ME

VOID OVER \$40,207.00

NOT VALID AFTER 60 DAYS

⑈ 500277⑈ ⑆011201539⑆ 80 025 354⑈



GAS PIPELINES CENTRAL  
P.O. Box 20008  
3800 Frederica St.  
Owensboro, KY 42304  
Tel. 270/926-8686  
Fax. 270/683-5835

*Daryl R. Johnson*  
*Manager, Rates*  
*Phone: 270/688-6726*  
*Fax: 270/683-5960*

February 23, 2001

Dear Shipper:

By order dated December 26, 2000, the Commission approved the Stipulation and Agreement entered into between the Market Oversight and Enforcement Staff, the Office of General Counsel and Williams Gas Pipelines Central in Docket IN01-2-000 regarding Williams' Webb storage field.

Enclosed please find a check representing your portion of Williams' refund related to such Stipulation and Agreement. Also enclosed is a schedule reflecting the allocation by shipper of the total principal and interest resulting from the Stipulation and Agreement.

If you have any questions related to your refund, please contact me by phone at (270) 688-6726 for by e-mail at [daryl.r.johnson@williams.com](mailto:daryl.r.johnson@williams.com).

Sincerely,

A handwritten signature in black ink that reads "Daryl R. Johnson".

Enclosures

**Williams Gas Pipelines Central, Inc.  
Storage Customer Refunds Pursuant  
To Stipulation & Agreement**

**Attachment B**

<u>Customer</u>	<u>Allocation Factor</u>	<u>Refund</u>
Altamont Municipal Gas Authority	0.000562	\$ 766
Americus Gas Company, Inc	0.000227	\$ 309
Amoco Energy Trading Corp.	0.002167	\$ 2,952
Argonia Kansas, City of	0.000141	\$ 192
Auburn Kansas, City of	0.000530	\$ 722
Avant Utilities Authority	0.000085	\$ 116
Billings Public Works	0.000187	\$ 255
Burlington Oklahoma, City of	0.000097	\$ 132
City Utilities of Springfield, Mo.	0.052659	\$ 71,737
Cleveland Oklahoma, City of	0.000937	\$ 1,276
Copan Public Works Authority	0.000283	\$ 386
Denison Kansas, City of	0.000087	\$ 119
Duke Energy Fuels, L.P.	0.000174	\$ 237
Eckert Gas Co.	0.000027	\$ 37
Flint Hills Gas Co., Inc.	0.000034	\$ 46
Ford Kansas, City of	0.000143	\$ 195
Freedom Municipal Trust Authority	0.000131	\$ 178
Gate Oklahoma, Town of	0.000059	\$ 80
Granby Missouri, City of	0.000667	\$ 909
Greeley Gas Co., Div of Atmos Energy	0.009118	\$ 12,421
Grove Municipal Services Authority	0.002340	\$ 3,188
Hamilton Kansas, City of	0.000074	\$ 101
Howard Kansas, City of	0.000222	\$ 302
Iola Kansas, City of	0.003027	\$ 4,124
Kansas Gas Service Co.	0.325443	\$ 443,349
Kansas Industrial Energy Supply Co.	0.003588	\$ 4,888
Kansas Municipal Gas Agency	0.008949	\$ 12,191
Lebo Kansas, City of	0.000176	\$ 240
Liberal Missouri, City of	0.000191	\$ 260
Mannford Public Works Authority	0.000444	\$ 605
McLouth Kansas, City of	0.000180	\$ 245
Missour Gas Energy	0.455384	\$ 620,366
Mulberry Kansas, City of	0.000197	\$ 268
Nebraska Public Gas Agency	0.002883	\$ 3,927
Nelagoney Rural Gas	0.000014	\$ 19
Neodesha Kansas, City of	0.001140	\$ 1,553
Oneok Gas Marketing Co.	0.001131	\$ 1,541
Orlando Oklahoma, Town of	0.000064	\$ 87
Oronogo Missouri, City of	0.000043	\$ 59
Plattsburg Missouri, City of	0.000970	\$ 1,321
Public Service Co. of Colorado	0.000113	\$ 154
Reading Kansas, City of	0.000061	\$ 83
Reliant Energy Arkla	0.001153	\$ 1,571
Severy Gas Co.	0.000106	\$ 144
Tenaska Marketing Co.	0.021910	\$ 29,848
The Lawrence Paper Co.	0.000146	\$ 199
United Cities Gas Co.	0.053915	\$ 73,448
Utilicorp United, Inc.	0.029514	\$ 40,207
Viola Kansas, City of	0.000059	\$ 80
Wakita Utilities Authority	0.000195	\$ 266
Wann Public Works Authority	0.000055	\$ 75
Williams Gas Marketing & Trading	0.017998	\$ 24,519
<b>Total Refund</b>	<b>1.000000</b>	<b>\$ 1,362,293</b>
		<b>\$ 1,362,293</b>

**Williams Pipeline  
IN01-2-000 (Webb Storage Field)**

Settlement Amount: \$40,207.00

		<u>Allocation %</u>	<u>Amount</u>
1.	MPS	56.52%	\$22,723.01
	KPS/PNG	43.48%	\$17,483.99
			\$40,207.00

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WILLIAMS GAS PIPELINES CENTRAL, INC.  
REFUND ALLOCATION  
Feb-01

Docket No. IN01-2-000 Webb Storage Refund

Journal Entry

Debit GSS Refund Account					\$40,207.00
Credit 229.001	5198	100	MPD		(\$22,723.01)
Credit 229.001	5191	100	PND-KS		(\$17,483.99)

**UTILICORP UNITED**

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January 22, 2001

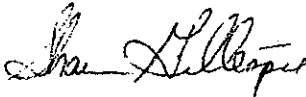
Mr. Tim Meyer  
Williams Gas Pipeline – SouthCentral  
3800 Frederica Street  
Owensboro, KY 42304

Dear Mr. Meyer:

Per our conversation on January 22, 2001, I'm submitting a written request for issuance of refund that relates to the Webb Storage Field. The Missouri Public Service Commission has requested that all eligible Missouri LDC's elect to receive a refund versus crediting to the Gas Supply Realignment (GSR) costs. Please issue refund of UtiliCorp United, Inc. portion.

If you have any questions or concerns, please don't hesitate to contact me at (402) 926-5254 or by email: [sgillesp@utilicorp.com](mailto:sgillesp@utilicorp.com). I appreciate your prompt attention to this matter.

Sincerely,



Shawn Gillespie  
Sr. Gas Supply Representative  
UtiliCorp United, Inc.

CC: Karen Russell  
Kent Kopetzky



# Missouri Public Service Commission

POST OFFICE BOX 360  
JEFFERSON CITY, MISSOURI 65102  
573-751-3234  
573-751-1847 (Fax Number)  
<http://www.psc.state.mo.us>

**BRIAN D. KINKADE**  
Executive Director  
**GORDON L. PERSINGER**  
Director, Research and Public Affairs  
**WESS A. HENDERSON**  
Director, Utility Operations  
**ROBERT SCHALLENBERG**  
Director, Utility Services  
**DONNA M. KOLILIS**  
Director, Administration  
**DALE HARDY ROBERTS**  
Secretary/Chief Regulatory Law Judge  
**DANA K. JOYCE**  
General Counsel

Commissioners  
**SHEILA LUMPE**  
Chair  
**M. DIANNE DRAINER**  
Vice Chair  
**CONNIE MURRAY**  
**ROBERT G. SCHEMENAUER**  
**KELVIN L. SIMMONS**

January 12, 2001

Mr. Steve Jurek  
Utilicorp United Inc.  
1815 Capitol Ave.  
Omaha, NE 68102

Mr. Jurek:

The Missouri Public Service Commission ("MoPSC") has become aware of a Federal Energy Regulatory Commission ("FERC") order, issued December 26, 2000, which instructs Williams Gas Pipelines Central, Inc. ("Williams") to refund \$1,362,293 to its storage customers on or before January 25, 2001. 93 FERC ¶ 61,309. This refund is intended to compensate customers, in part, for costs incurred as a result of Williams' loss of Webb field gas that migrated west of the storage field's certificated boundary from October 1993 to May 2000.

Williams has offered two options for eligible storage customers to receive their refunds. Williams will credit the eligible customer's outstanding invoices by applying the credit against the direct bills of those customers who received direct bills related to the settlement of Williams' gas supply realignment ("GSR") costs that the FERC approved in Docket No. RP99-257, et al. Alternatively, any eligible customer may elect to receive its respective refund **by requesting** a check for the full amount of its refund from Williams and Williams will honor such request.

Given the circumstances underlying this refund, the MoPSC Staff suggests that the eligible Missouri LDC's elect to receive a refund check from Williams for distribution to the LDCs' sales customers. If after reviewing this FERC order, Utilicorp United Inc. believes a different handling of this refund to be more appropriate, please call me at (573) 751-2978 to discuss this matter further.

Sincerely,

Warren T. Wood, P.E.  
Utility Regulatory Manager

93 FERC ¶ 61,309

UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;  
William L. Massey, Linda Breathitt,  
and Curt Hébert, Jr.

Williams Gas Pipelines Central, Inc.

Docket No. IN01-2-000

## ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued December 26, 2000)

The Market Oversight and Enforcement section, Office of the General Counsel (MOE) and Williams Gas Pipelines Central, Inc. (Williams) entered into a Stipulation and Consent Agreement (Agreement) to resolve all issues concerning Williams' operation of its Webb storage field, located in Grant County, Oklahoma. We approve the Agreement without modification, as discussed below.<sup>1</sup>

As set forth in the Agreement, from about 1972 through the present, substantial volumes of Webb field gas have migrated in a westerly direction outside the certificated boundary of the field. Starting in 1974, Williams (including its predecessors that operated the field) became aware that storage gas was migrating west of the certificated boundary of the field. Williams also believed that offset well operators west of the field were extracting storage gas. For years after 1974, Williams purchased Webb field storage gas that these operators produced.

Williams took inadequate steps to stem the migration of gas from the Webb field. Fifteen years after Williams became aware of the matter, it filed an application with the Commission to increase the size of the field. The Commission approved the application,<sup>2</sup> which authorized Williams to operate a 1,040-acre buffer zone west of the field. As the Commission stated at the time, the buffer zone would allow westward-migrating gas to

<sup>1</sup>In an August 1998 order, the Commission reserved authority to take enforcement action relating to Williams' operation of the Webb field. See Williams Gas Pipelines Central, Inc., 84 FERC ¶ 61,176 at 61,922 (1998).

<sup>2</sup>See Williams Natural Gas Company, 49 FERC ¶ 62,160 (1989) (the 1989 certificate order).

FERC - DOCKETED

DEC 26 2000

001228-0053-2

Attachment B

Williams Gas Pipelines Central, Inc.  
 Net Storage Injections By Customer  
 October 1993 Through May 2000

<u>Customer</u>	<u>Net Storage Injection</u>	<u>Allocation Factor</u>
Altamont Municipal Gas Authority	119,799	0.000562
Americus Gas Company, Inc	48,345	0.000227
Amoco Energy Trading Corp.	461,899	0.002167
Argonia Kansas, City of	30,074	0.000141
Auburn Kansas, City of	112,944	0.000530
Avant Utilities Authority	18,126	0.000085
Billings Public Works	39,863	0.000187
Burlington Oklahoma, City of	20,642	0.000097
City Utilities of Springfield, Mo.	11,223,688	0.052659
Cleveland Oklahoma, City of	199,773	0.000937
Copan Public Works Authority	60,339	0.000283
Denison Kansas, City of	18,536	0.000087
Duke Energy Fuels, L.P.	36,992	0.000174
Eckert Gas Co.	5,680	0.000027
Flint Hills Gas Co., Inc.	7,214	0.000034
Ford Kansas, City of	30,529	0.000143
Freedom Municipal Trust Authority	27,922	0.000131
Gate Oklahoma, Town of	12,497	0.000059
Granby Missouri, City of	142,143	0.000667
Greeley Gas Co., Div of Atmos Energy	1,943,392	0.009118
Grove Municipal Services Authority	498,672	0.002340
Hamilton Kansas, City of	15,668	0.000074
Howard Kansas, City of	47,234	0.000222
Iola Kansas, City of	645,208	0.003027
Kansas Gas Service Co.	69,364,612	0.325443
Kansas Industrial Energy Supply Co.	764,805	0.003588
Kansas Municipal Gas Agency	1,907,388	0.008949
Lebo Kansas, City of	37,566	0.000176
Liberal Missouri, City of	40,689	0.000191
Mannford Public Works Authority	94,534	0.000444
McLouth Kansas, City of	38,278	0.000180
Missour Gas Energy	97,060,174	0.455384
Mulberry Kansas, City of	42,056	0.000197
Nebraska Public Gas Agency	614,419	0.002883
Nelagoney Rural Gas	3,013	0.000014
Neodesha Kansas, City of	242,918	0.001140
Oneok Gas Marketing Co.	241,011	0.001131
Orlando Oklahoma, Town of	13,596	0.000064
Oronogo Missouri, City of	9,152	0.000043
Plattsburg Missouri, City of	206,813	0.000970
Public Service Co. of Colorado	24,154	0.000113
Reading Kansas, City of	12,961	0.000061
Reliant Energy Arkla	245,718	0.001153
Severy Gas Co.	22,622	0.000106
Tenaska Marketing Co.	4,669,909	0.021910
The Lawrence Paper Co.	31,209	0.000146
United Cities Gas Co.	11,491,483	0.053915
Utilicorp United, Inc.	6,290,655	0.029514 = \$40,206.72
Viola Kansas, City of	12,604	0.000059
Wakita Utilities Authority	41,626	0.000195
Wann Public Works Authority	11,637	0.000055
Williams Gas Marketing & Trading	3,836,594	0.018000
Total Net Storage Injections	213,139,375	1.000002

Docket No. IN01-2-000

3

In April 2000, Williams filed an application to amend its Webb field certificate to expand part of the western boundary of the field.<sup>5</sup> This filing was a necessary precondition for Williams to seek to expand the field in the future because Williams' authority to do so pursuant to the Commission's 1989 certificate order had expired. In the Agreement, Williams agrees not to seek recovery in any proceeding before the Commission for costs it incurs in connection with preparing or pursuing the April 2000 filing. Finally, Williams agrees not to seek recovery in any proceeding before the Commission for additional losses of gas from the Webb field that are due to westward migration of gas, except in the limited circumstances set forth in the Agreement.

The Agreement resolves all claims by the Commission against Williams relating to the operation of the Webb field through the effective date of this order. The Agreement does not preclude any Commission action relating to Williams' gas storage rates and accounting for storage gas, except to the extent those subjects are specifically addressed in the Agreement.

The Commission finds that the Agreement is fair and reasonable and in the public interest.

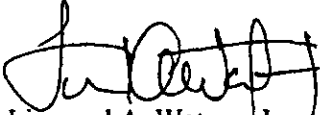
The Commission orders:

(A) The Commission approves the attached Stipulation and Consent Agreement without modification.

(B) The Commission's approval of the Agreement does not constitute precedent regarding any principle or issue in any proceeding.

By the Commission.

( S E A L )



Linwood A. Watson, Jr.,  
Acting Secretary.

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<sup>5</sup>Docket No. CP00-166-000. Williams' application in this docket is pending.

## STIPULATION AND CONSENT AGREEMENT

### I.

The Market Oversight and Enforcement Section, Office of the General Counsel (Market Oversight and Enforcement) and Williams Gas Pipelines Central, Inc. (Williams) enter into this Stipulation and Consent Agreement (Agreement), which resolves all issues arising from or pertaining to a non-public, preliminary investigation that Market Oversight and Enforcement conducted under Part 1b of the Commission's regulations,<sup>1</sup> concerning Williams' operation of its Webb natural gas storage field.

### II.

Market Oversight and Enforcement and Williams hereby stipulate and agree on the following:

A. The Webb field is located in Grant County, Oklahoma and represents about 33 percent of Williams' total storage capacity. The gas in the field includes working gas, which is readily injectable and withdrawable, and cushion gas, which is unproduced native gas plus injected gas. The cushion gas represents that part of the inventory which must always be present to maintain pressure in the reservoir so that the storage field meets its deliverability requirements. A depiction of the field, with references to injection/withdrawal wells and offset operators, appears in Attachment A to this Agreement.

B. In December 1963, the Commission issued Williams' predecessor, Cities Service Gas Company (Cities Service),<sup>2</sup> a certificate to construct and operate the Webb field.<sup>3</sup> The Webb field includes three major formations known as the Mississippi Chat, Red Fork and Skinner. The certificated maximum reservoir capacity inventory of the

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<sup>1</sup>18 C.F.R. Part 1b (2000).

<sup>2</sup>In November 1983, Cities Service became Northwest Central Pipeline Corporation. In January 1987, Northwest Central became Williams Natural Gas Company. 54 FERC ¶ 61,134 (1991). The company became Williams Gas Pipelines Central, Inc. in 1998. Except where otherwise noted, reference to Williams in this Agreement refers to Williams and its predecessors.

<sup>3</sup>30 FPC 1612 (1963). The Commission modified the authorization in November 1965, 34 FPC 1209; June 1967, 37 FPC 1049; June 1977, 58 FPC 2717; and November 1989, 49 FERC ¶ 62,160.

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Williams Gas Pipelines Central, Inc.**

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Webb field is 55.3 Bcf at the maximum wellhead shut-in pressure of 2,000 pounds per square inch gauge (psig).

C. Williams represented to the Commission in the certificate application that the composition of the field is sufficiently thick and impervious to prevent migration of the stored gas. It also represented that the field is bounded by a major fault on the west side of the field.

D. In 1965-67, Williams drilled and fractured new wells that partially penetrated the Mississippi Chat. Injection began in April 1966. Independent offset operators with facilities located slightly west of the western certificated boundary of the field began producing Webb field gas in 1972. This production was possible because these facilities communicated with the storage strata in the field. By 1974, Williams believed that storage gas was migrating west of the certificated boundary of the field although no conclusive study had been performed. During this time and for years thereafter, Williams engaged in correspondence with one offset operator whose production facilities were located slightly west of the field's western boundary. To reduce the migration of storage gas outside the certificated boundary of the field, Williams permitted this operator to establish facilities within the field and to produce oil as long as it returned produced storage gas to Williams. In 1977-78, Williams drilled 10 new wells to increase the field's deliverability. Williams also fractured wells in this time period and increased the maximum allowable pressure at the field to 1,875 psig in 1977. By October 1985, 47 injection/withdrawal wells and 11 observation wells were in the field. Around 1986, Williams practiced "topping off" the field. Topping off refers to injecting additional gas during the withdrawal cycle to hold the pressure near the maximum value.

E. Williams conducted several studies of the Webb field in the mid-1980s. According to these studies and statements by persons employed by Williams during this time, (1) one of the formations containing storage gas in the field (Red Fork) is not bounded by a major fault on its western side; (2) the increase of the maximum wellhead pressure in 1977-78 to serve customer heating season demands exacerbated losses from the field; (3) the presence of certain offset operators west of the field created lower reservoir pressures that attracted migrating gas; (4) the offset operators west of the field were extracting substantial quantities of gas, the majority of which was storage gas; (5) losses during the mid-1980's averaged more than 4 percent of injections; (6) Williams believed offset operators west of the field were extracting storage gas in part because these operators were using wells that were originally drilled as oil wells and the gas they were extracting had a very high gas to oil ratio; and (7) Williams was purchasing gas that

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it believed included a substantial amount of storage gas from some of the offset operators.

F. In April 1989, Williams filed an application to amend the Webb field certificate to include an additional 1,040 acres adjacent to the western boundary of the field as a buffer zone. The effect of its proposal would be to move the western boundary of the field one-half mile to the west. In support of its application, Williams stated that "there appears to be a potential for loss of storage gas to producing wells located west of the west flank of the storage area."<sup>4</sup>

G. In November 1989, the Commission, under delegated authority, approved the certificate amendment that Williams requested.<sup>5</sup> In the order, the Commission noted that unusually high amounts of gas were extracted by two production wells from the Red Fork formation outside the certificated boundary of the field and within the proposed buffer zone. The Commission also noted that production of this gas adhered to a cycle that mirrored peak gas injection periods in the Webb field. The Commission concluded that the addition of the proposed buffer zone would assure the operating integrity of the field.

H. Williams failed to acquire the 1,040 acre buffer zone within the two-year period provided by the Commission. In 1990, Williams commenced a condemnation proceeding against property known as the Ultramar Lease. In February 1992, Williams purchased this lease, consisting of 160 acres west of the field, or 15.35 percent of the buffer zone, and which produced a majority of the gas produced by offset operators. In October 1996, Williams began discussions with other offset operators that owned or operated facilities within the portion of the buffer zone in which Williams had not acquired right, title and interest in the underlying gas. In January 1997, Williams filed suit against two offset operators, San Point Production, Inc. and Baker Eberle Energy Corporation, in the 4th District Court, Grant County, Oklahoma. To date these discussions and the referenced litigation have not resulted in Williams acquiring any additional right, title and interest in gas underlying the buffer zone approved in the certificate amendment.

I. Overall, the field has lost an estimated 15 BCF of gas. The field currently loses approximately 220,000 Mcf annually. The only appreciable losses sustained by the

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<sup>4</sup>Certificate application, Docket No. CP89-1276-000, filed April 27, 1989, at 5.

<sup>5</sup>49 FERC ¶ 62,160 (1989).

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field are gas production from the offset leases. During the period from 1992 through 1999, the field lost approximately 1.9 Bcf of gas. The cost of gas lost from the field during this period was passed through to Williams' customers.

J. The total gas inventory of the Webb field was 39.8 Bcf as of December 31, 1997. A volume of 56.12 Bcf was booked by Williams on the same date.

K. A settlement of a prior Enforcement investigation required Williams to perform an independent study of losses from the Webb field.<sup>6</sup> In October 1998, the firm of Fairchild, Ancell & Wells, Inc. produced a study that proved conclusively that offset operators had produced Webb field gas for many years. Prior to this study, Williams had no independent studies that proved conclusively that the production from offset operators was storage gas.

L. In April 2000, Williams filed an application to amend its certificate to operate the Webb storage field. In its filing, Williams requested authority to, among other things, acquire 480 acres on the west side of the field as a buffer zone.<sup>7</sup> The acreage is part of the 1,040 acre expansion of the storage field that the Commission authorized in 1989. Williams' application is pending.

**III.**

A. Within 30 days of the date on which the Commission approves this Agreement, without modification, and that approval becomes final, Williams will refund to the customers listed in Appendix B the sum of \$1,362,293 according to the allocation factor set forth therein. The allocation factor is based on the respective percentages of gas that Williams' customers injected into storage during the period October 1993 through May 2000. To effectuate the refund, Williams may credit such customers' outstanding invoices by applying the credit against the direct bills of those customers who received direct bills related to the settlement of Williams' Gas Supply Realignment (GSR) costs that the Commission approved in Docket No. RP99-257, et al.<sup>8</sup> Alternatively, any such

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<sup>6</sup>Williams Gas Pipelines Central, Inc. 84 FERC ¶ 61,176 (1998).

<sup>7</sup>Certificate application, Docket No. CP00-166-000, filed April 3, 2000.

<sup>8</sup>On August 30, 1999, the Commission approved an offer of settlement to resolve Williams' recovery of various costs, including GSR costs. Williams Gas Pipelines  
(continued...)

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Williams Gas Pipelines Central, Inc.**

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customer listed in Appendix B may elect to receive its respective refund by requesting a check for the full amount of its refund from Williams and Williams will honor such request. Within 30 days of the last date by which Williams agrees to make the refund described in this paragraph, Williams will file with the Commission in the docket of the order approving this Stipulation and Consent Agreement, a refund report showing that Williams has completely discharged its refund obligation or making such other statement and explanation as may apply.

B. Within 6 months of the date on which the Commission approves this Agreement, without modification, and that approval becomes final and no longer subject to appeal, Williams will file a limited Natural Gas Act Section 4 rate filing consisting of a revised tariff sheet(s) which sets forth reduced base tariff rates reflecting only the elimination of \$1,584,326 from storage rate base. The limited Section 4 filing must include supporting work papers showing the cost of service effect of the reduced rate base and the resultant derivation of rates. However, if Williams files a general Section 4 rate case before it makes the limited Section 4 filing referenced above, it will include in the general Section 4 rate case the removal of \$1,584,326 from storage rate base and will not be required to make the limited Section 4 filing. If Williams files a general Section 4 rate case in lieu of a limited Section 4 filing, Williams will (i) include in the transmittal letter accompanying the general Section 4 rate filing a statement that explicitly notes the inclusion of the removal of the sum listed above from its storage rate base, and (ii) will include in the accompanying papers the supporting work papers that it would have filed had it filed the limited Section 4 filing. The limited rate filing is to reflect removal of approximately 16,476,000 dekatherms of gas from Williams' rate base. This amount of gas is approximately equal to the difference between the total gas inventory in the field and the volume of gas that Williams has recorded in its inventory records. The amount of the revision reflects the fact that a portion of the lost gas was native gas that Williams carries at no value and another portion of the lost gas was cushion gas that Williams carries at its average cost of gas. The annual cost of service impact of the filing will be approximately \$235,600. In the event that Williams makes a limited Section 4 filing, as discussed above, the Commission's order approving this Agreement shall constitute all necessary authority for Williams to place said tariff sheet(s) into effect on the first day of

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<sup>8</sup>(...continued)

Central, Inc., 88 FERC ¶ 61,198 (1999). In the order, the Commission stated that the offer of settlement provides for Williams to recover a specified amount of GSR costs "through direct bills to Williams' 'GSR paying firm customers with transportation and/or sales contracts during the effective period..." *Id.* at 61,676.

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Williams Gas Pipelines Central, Inc.**

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the first calendar month following said filing. Further, Williams will make the necessary entries to its books of account to reflect the amounts adjusted for ratemaking purposes as set forth above. The outcome will be that Williams' books of accounts will be synchronized with the amounts of storage gas inventory in its rate base for the Webb field.

C. Williams will operate the Webb field such that the maximum inventory of the field will not exceed 46 BCF and the maximum storage field pressure will not exceed 1,850 psig wellhead pressure as measured by a seven-day shut-in procedure.

D. Williams will operate wells located in the western half of sections 35, 2 and 11 in the Webb field, depicted in Attachment A, as withdrawal or observation wells only and not as injection wells.

E. Williams will not seek recovery for, or recover, through any proceeding before the Commission, any costs or expenses it incurs or has incurred to prepare and pursue its April 2000 NGA section 7(c) certificate application in Docket No. CP00-166-000 or any subsequent subdocket. If during the pendency of Docket No. CP00-166-000 or any subsequent subdocket, or during the two-year period following termination of the final subdocket in that proceeding, Williams files a general Section 4 rate change application it must, as part of the application, separately show an itemized list of all costs and expenses it incurred in connection with the preparation of and pursuit of approvals for the application filed in Docket No. CP00-166-000 or any subsequent subdocket in a manner consistent with the Uniform System of Accounts and it must note this itemization clearly in the transmittal letter accompanying any such filing. However, nothing in this agreement shall preclude Williams from seeking to recover the cost of acquiring the gas storage rights and related costs associated with the acquisition of the additional 480 acres requested in that docket.

F. Williams may not seek recovery for, or recover, in any proceeding before the Commission, any loss of gas that has occurred or may occur at the Webb field due to the westward migration of gas outside the current or any future certificated boundary of the field, *provided*, however, that Williams may seek recovery for any loss of gas at the field that is due to (i) ordinary losses not including losses due to westward migration outside the certificated boundary of the field, and/or (ii) westward migration outside the certificated boundary of the field (including any extensions of that boundary as the Commission may authorize) to the extent Williams demonstrates in any filing in which it seeks recovery for such losses that (a) such losses result from offset production wells

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Williams Gas Pipelines Central, Inc.**

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drilled or recompleted after the date of this Agreement, and (b) Williams' actions regarding such losses were prudent.

G. Nothing in this Agreement shall be construed to bear on Williams' pending application in Docket No. CP00-166-000. Except for those cost and rate matters specifically addressed herein, nothing in this Agreement shall preclude any action by the Commission regarding Williams' storage rates and accounting for storage gas.

**IV.**

A. Market Oversight and Enforcement and Williams agree that they enter into this Agreement voluntarily and that other than the agreements set forth herein, no tender, offer, or promise of any kind whatsoever has been made by any party to this Agreement, or any member, employee, officer, director, agent or representative of any such party, to induce the other party to enter into this Agreement.

B. If the Commission does not issue an order which becomes final approving this Agreement in its entirety, without modification, this Agreement shall be null and void and of no effect whatsoever and neither Market Oversight and Enforcement nor Williams shall be bound by any of its provisions or terms, unless they otherwise agree in writing.

C. Should the Commission's order referenced in Section IV.B. above be subsequently modified on appeal in a fashion which modifies this Agreement, then this Agreement shall be null and void and of no effect whatsoever and neither Market Oversight and Enforcement nor Williams shall be bound by any of its provisions or terms, unless they otherwise agree in writing. Further, in such event, all monies Williams has paid hereunder shall be returned to Williams. To effectuate the recoupment of monies paid, Williams shall surcharge each applicable customer and shall issue an invoice for such amounts consistent with Williams' tariff (See General Terms and Conditions, Section 18). Williams shall accrue interest at the FERC rate under 18 CFR § 154.501 from the date the monies were disbursed until the date the recoupment is completed.

D. Except as expressly stipulated and acknowledged and agreed herein, neither Market Oversight and Enforcement nor Williams makes or has made any admissions or acknowledgements or agreements in connection herewith.

**Stipulation and Consent Agreement  
Williams Gas Pipelines Central, Inc.**

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E. The undersigned representative of Williams affirms that he has read the representations set forth in this Agreement, that all of the matters set forth herein are true and correct to the best of his knowledge, information, and belief, and that he understands that this Agreement is entered into by Market Oversight and Enforcement in express reliance on those representations.


F. The provisions of this Agreement are binding on Williams and its agents, successors and assigns.

G. Market Oversight and Enforcement agrees to a full and complete settlement of all administrative, civil or other claims the Commission has or may have against Williams or any of its predecessors, officers, directors, or employees, either before the Commission or in the courts, relating to the operation of the Webb field from the date of its certification until the date on which the Commission approves this Agreement.



H. Williams waives judicial review by any court of any Commission order approving this Agreement in its entirety, without modification.

I. Each of the undersigned warrants that he or she is an authorized representative of the party designated, is authorized to bind such party, and accepts this Agreement on the party's behalf.

Agreed to and accepted:

  
\_\_\_\_\_  
Andrea Wolfman, Lead Counsel  
Market Oversight and Enforcement

11/29/00  
Date

  
\_\_\_\_\_  
[name and title of signator]   
Williams Gas Pipelines Central, Inc.

11-21-00  
Date

Senior Vice President  
and General Manager



516 467 3500 mark

UTILICORP UNITED INC  
ATTN: ROBERT EADS  
20 WEST 9TH STREET 7-263  
KANSAS CITY MO 64105

NO. 500142

DETACH THIS STATEMENT AND RETAIN FOR YOUR FILES  
007397 002 UTILICORP UNITED INC

INVOICE NUMBER	DATE	VOUCHER NO.	P.O./ CONTRACT NO.	GROSS	DISCOUNT	NET
7921	01/26/01	334170		84,864.00	0.00	84,864.00
RP93-109 ENVIRONMENTAL COSTS REFUND						
*TOTAL*				84,864.00	0.00	84,864.00

01/31/01 500142

**Williams**  
P.O. BOX 2000  
Owensboro, Kentucky 42301  
(270) 326-8866

NO 500142

DATE	AMOUNT
01/31/01	*****\$84,864.00

WILLIAMS GAS PIPELINES CENTRAL, INC.

PAY TO THE ORDER OF UTILICORP UNITED INC  
ATTN: ROBERT EADS  
20 WEST 9TH STREET 7-263  
KANSAS CITY MO 64105

BY: *Mick A. Baile*  
Vice President

BY: \_\_\_\_\_

BankBoston Maine, N.A.  
SOUTH PORTLAND, ME

VOID OVER \$84,864.00

NOT VALID AFTER 60 DAYS

⑈ 500142 ⑆ ⑆ 011201539 ⑆ 80 025 354 ⑆



GAS PIPELINES CENTRAL  
P.O. Box 20008  
3800 Frederica St.  
Owensboro, KY 42304  
Tel. 270/926-8686  
Fax. 270/683-5835

Daryl R. Johnson  
Manager, Rates  
Phone: 270/688-6726  
Fax: 270/683-5960

January 31, 2001

Dear Customer:

Today Williams Gas Pipelines Central, Inc. (Williams) filed in Docket No. RP93-109, a Stipulation and Agreement in settlement of the environmental costs related to that proceeding, as more fully explained in the Stipulation and Agreement. As part of that settlement, Williams is refunding a total of \$1,515,517 to its customers.

Your portion of Williams' refund related to the aforementioned settlement is enclosed. Also enclosed is a copy of the Stipulation and Agreement as filed.

If you have any questions related to your refund, please contact me by phone at (270) 688-6726 or by e-mail at [daryl.r.johnson@williams.com](mailto:daryl.r.johnson@williams.com).

Sincerely,

A handwritten signature in black ink, appearing to read "Daryl R. Johnson".

Enclosures

**GARY W. BOYLE**  
Senior Counsel - Gas Pipeline Central  
918/573-2359  
918/573-4195 office fax  
gary.boyle@williams.com

January 31, 2001

David P. Boergers  
Federal Energy Regulatory Commission  
888 First Street, N.E.  
Washington, DC 20426

RE: Williams Natural Gas Co., Docket No. RP93-109-000

Dear Mr. Boergers:

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (Commission), 18 C.F.R. § 385.602, Williams Gas Pipelines Central, Inc., formerly named Williams Natural Gas Company (Williams), hereby submits an original and fourteen (14) copies of a Stipulation and Agreement (Agreement) in the captioned proceeding.

A. EXPLANATORY STATEMENT

On April 30, 1993, Williams filed a general Section 4 rate filing proposing, among other things, to amortize over a three-year period actual past period environmental costs of \$4.2 million. On November 22, 1995, the Presiding ALJ issued an Initial Decision approving the three-year amortization of environmental costs with a procedure for refunding amounts that Williams recovered from third parties. On December 19, 1996, the Commission affirmed in part and reversed in part the ALJ's Initial Decision rejecting Williams' proposed amortization in favor of the "test period" method and ruling that \$1.4 million was a reasonable representation of the level of environmental costs to be recovered in rates. Williams appealed that decision to the D. C. Circuit Court of Appeals. The D.C. Circuit Court of Appeals remanded the environmental cost issue to the Commission finding that it had not adequately explained why it had approved a \$1.4 million annual environmental allowance. The active parties have engaged in discovery, Williams has filed direct testimony and all parties have spent time discussing settlement. This Stipulation and Agreement represents a final, comprehensive resolution of environmental costs in this proceeding. Williams believes this settlement is supported by all active parties.

David P. Boergers  
Page 2  
January 31, 2001

B. PROCEDURES AND COMMENTS

Williams respectfully requests that the instant Agreement be transmitted forthwith to Presiding Administrative Law Judge Harfeld pursuant to Rule 602(b)(2)(i) of the Commission's Rules. Pursuant to Rule 602(f)(2), initial comments on this Agreement must be filed on or before February 20, 2001, and reply comments must be filed on or before March 2, 2001. Failure to file comments will be deemed a waiver of the right to file comments on the offer of settlement.

C. WAIVERS

Williams respectfully requests waiver of any provisions of the Commission's regulations and any other waivers which may be necessary for approval of the Agreement as proposed herein.

D. SERVICE

The Agreement, together with all attachments thereto, is this day being served pursuant to Rule 602(d)(1) upon all participants listed on the official restricted service list in this proceeding on file with the Secretary of the Commission.

Sincerely,

Gary W. Boyle  
Senior Counsel

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

Williams Natural Gas Company

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Docket No. RP93-109

**STIPULATION AND AGREEMENT  
(January 31, 2001)**

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (Commission), 18 C.F.R. § 385.602, Williams Gas Pipelines Central, Inc., formerly named Williams Natural Gas Company (Williams), submits this Stipulation and Agreement in settlement of the remaining contested issues in the captioned proceeding.

**DESCRIPTION OF PROCEEDING**

On April 30, 1993, Williams made a general Section 4 rate filing (Docket No. RP93-109). The Commission suspended the effective date of the proposed rate increase until November 1, 1993, and set the matter for hearing.<sup>1</sup> Evidentiary hearings before an ALJ were conducted in 1994. Initial and reply briefs were filed by various parties. Among the many issues addressed at the hearing was the issue of Williams' recovery of its environmental costs. Williams proposed to amortize over a three-year period actual past period costs of \$4.2 million instead of projecting environmental costs under a test period methodology. By amortizing these costs over three years, Williams would have been allowed to recover \$1.4 million each year. On November 22, 1995, the Presiding Judge issued an Initial Decision which approved the three-year amortization with a procedure for refunding any amounts Williams recovered from third parties, such as liability insurance carriers or the suppliers of the PCB-laden material.<sup>2</sup> Several parties filed exceptions to the Initial Decision. Williams filed a new Section 4 rate case in 1995,

<sup>1</sup> Williams Natural Gas Co., 63 FERC ¶ 61,241 (1993).

<sup>2</sup> Williams Natural Gas Co., 73 FERC ¶ 63,015 (1995).

with the result that the instant rate case covers a locked-in period of November 1, 1993, through July 31, 1995.

On December 19, 1996, the Commission affirmed in part and reversed in part the ALJ's Initial Decision.<sup>3</sup> The Commission rejected Williams' proposed amortization in favor of the "test period" method.<sup>4</sup> The Commission determined that the \$1.4 million annual amount that the participants and the ALJ arrived at using an amortization method was a reasonable equivalent of Williams' actual Polychlorinated Biphenyl (PCB) clean-up related test period costs for use as a projection of Williams' future annual PCB costs under the test period methodology.<sup>5</sup>

On rehearing, Williams did not contest the Commission's requirement that it recover these costs based on a test period methodology but it did assert that the Commission erred in adopting an annual allowance of \$1.4 million for PCB clean-up costs. The Commission ruled that the \$1.4 million was a reasonable representation of the level of these costs to be recovered in rates given the record that had been developed.<sup>6</sup> Williams appealed that decision to the D.C. Circuit Court of Appeals.

The court granted Williams' petition and remanded the PCB issue to the Commission finding that it had not adequately explained why it had approved use of the \$1.4 million figure. The court found that an allowance developed under an amortization method is not useful for applying past experience to project future costs as required by the test period method. The court

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<sup>3</sup> Williams Natural Gas Co., 77 FERC ¶ 61,277 (1996).

<sup>4</sup> 18 C.F.R. § 154.303.

<sup>5</sup> Williams Natural Gas Co., 77 FERC ¶ 61,277 at 62,181-183 (1996).

<sup>6</sup> Id. at 61,679-80.

also found that the Commission had not explained why Williams' \$3.9 million "test period actual" figure was inadequate.

On October 13, 2000, the Commission directed the Chief Administrative Law Judge to appoint an Administrative Law Judge to preside over a hearing in this matter and encouraged the parties to reach a settlement. Williams has filed direct supplemental testimony, the Staff and Intervenors have engaged in discovery, and the parties have spent considerable time discussing settlement. This Stipulation and Agreement is a product of those discussions.

This Settlement is supported by all parties active in these proceedings and resolves all outstanding issues in this docket.

## SETTLEMENT PROVISIONS

### ARTICLE I

#### Environmental Cost of Service

Williams will be entitled to recover an annual environmental cost of service of \$1,700,000 for the locked-in period applicable in this docket. The Commission originally allowed Williams to recover an annual cost of service of \$1,355,813 for the locked-in period applicable in this docket. Applying the settlement environmental allowance to the original amount authorized by the Commission for the locked-in period results in a net additional amount due Williams of \$1,012,150 including interest at the Commission's established rates through January 31, 2001.

### ARTICLE II

#### Collection

Williams will collect the net cost of service increase of \$1,012,150 by set-off against the pass-through of insurance proceeds due on January 31, 2001. During calendar year 2000,

Williams collected \$2,808,519 from third-party insurers related to its environmental costs, including interest at the Commission's established rates through January 31, 2001. Under the Commission's prior orders in this proceeding, Williams is required to pass through to its customers 90% of any such third-party collections.<sup>7</sup> Williams has therefore allocated to its customers \$2,527,667 of its third-party collections. To effect the set-off provided for herein, Williams will refund a total of \$1,515,517 to its customers on January 31, 2001.

### ARTICLE III

#### Allocation and Payment

A. Williams will allocate its net pass-through of third-party proceeds to its firm customers based on firm reservation revenues during the twelve months ended September 30, 2000. The allocation, reflected on Appendix A, sets forth the amount to be refunded to each party under the terms of this Settlement.

B. Williams will make the refunds on Appendix A to each of the customers listed thereon on or before January 31, 2001.

C. If the Commission should issue a final and non-appealable order directing Williams to pass-through the net amount due under this Settlement in a manner inconsistent with Appendix A, Williams will have the right to correct each party's net refund by adjusting the amount of any future pass-through of third-party environmental collections, if any.

D. The parties agree that Williams' future pass-through of third-party environmental proceeds, if any, should be allocated to Williams' customers based on firm reservation revenues for the twelve months ended on the September 30 immediately preceding the date on which the

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<sup>7</sup> Williams Natural Gas Co., 77 FERC ¶ 61,277 at 62,182 (1996); Williams Natural Gas Co., 73 FERC ¶ 63,015 at 65,075 (1995).

pass-through payments are made. Any future payments related to third-party environmental proceeds shall continue to be refunded to customers by the 31<sup>st</sup> of January following the calendar year in which Williams receives the third-party proceeds. Williams will file a refund plan consistent with the allocation set forth in this paragraph no less than 30 days prior to the date on which refunds are required.

#### ARTICLE IV

##### Refund Report

This Stipulation and Agreement will serve as Williams' refund report in this proceeding related to its obligation to pass-through a portion of the third-party proceeds it received during calendar year 2000. The Commission's Order approving this Stipulation and Agreement will constitute approval of Williams' refund report and will resolve all remaining issues in this docket.

#### ARTICLE V

##### Effective Date

The Commission's order approving this Stipulation and Agreement shall constitute a waiver of the Commission's Rules and Regulations, including 18 C.F.R. Part 154, Subpart C, to the extent necessary to effectuate all of the provisions of this Stipulation and Agreement. This Stipulation and Agreement shall be effective on January 31, 2001, regardless of the date on which the Commission approves this Stipulation and Agreement.

#### ARTICLE VI

##### General Reservations

This Settlement Agreement is submitted for Commission approval pursuant to Rule 602 of the Commission's Rules of Practice and Procedure. If it does not become effective for any

reason it shall be considered privileged and not admissible in evidence or made a part of the record in any proceeding.

**ARTICLE VII**

Waiver of Regulation

Commission approval of this Settlement Agreement shall constitute the requisite waiver of any and all otherwise applicable Commission regulations to permit the implementation of the provisions hereof and a determination that the settlement is fair, reasonable, and in the public interest and consistent with NGPA § 502.

Respectfully submitted,

WILLIAMS GAS PIPELINES CENTRAL, INC.

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Gary W. Boyle  
The Williams Companies, Inc.  
P. O. Box 2400  
Tulsa, OK 74102

January 31, 2001

**Williams Gas Pipelines Central  
RP93-109 Environmental Cost  
Settlement Allocation**

**Appendix A**

<b>Shipper</b>	<b>12-Mos. Ending Sep 30, 2000 Revenue 1/</b>	<b>Percentage</b>	<b>Allocated Settlement Amount</b>
Acme Brick	\$ 79,109	0.0555%	\$ 841
AFG Industries	\$ 102,873	0.0722%	\$ 1,094
AG Processing	\$ 31,823	0.0223%	\$ 338
Altamont	\$ 40,371	0.0283%	\$ 429
Americus Gas	\$ 29,774	0.0209%	\$ 317
Amoco Energy	\$ 527,108	0.3698%	\$ 5,604
Aquila Energy Marketing	\$ 1,021	0.0007%	\$ 11
Aquila Energy Transportaion	\$ 3,601	0.0025%	\$ 38
Argonia	\$ 18,837	0.0132%	\$ 200
Auburn	\$ 98,286	0.0690%	\$ 1,045
Avant	\$ 10,402	0.0073%	\$ 111
Bayer	\$ 42,315	0.0297%	\$ 450
Billings	\$ 16,363	0.0115%	\$ 174
Burlington	\$ 6,511	0.0046%	\$ 69
Central Mo State Univ	\$ 42,701	0.0300%	\$ 454
Certainteed Co.	\$ 295,315	0.2072%	\$ 3,140
City Utilities of Springfield	\$ 5,284,997	3.7078%	\$ 56,192
Cleveland	\$ 108,339	0.0760%	\$ 1,152
CMS Field	\$ 163,681	0.1148%	\$ 1,740
Comm of Land Office	\$ 10,561	0.0074%	\$ 112
Conagra Energy	\$ 36,931	0.0259%	\$ 393
Copan	\$ 31,927	0.0224%	\$ 339
Cotton Valley	\$ 15,000	0.0105%	\$ 159
Denison	\$ 8,911	0.0063%	\$ 95
Duke Energy	\$ 2,640,836	1.8527%	\$ 28,078
Dynegy Mkt & Trade	\$ 2,014	0.0014%	\$ 21
Eckert Gas	\$ 2,324	0.0016%	\$ 25
Empire Dist. Electric	\$ 2,175,232	1.5261%	\$ 23,128
Energy One	\$ 154,251	0.1082%	\$ 1,640
Enserco Energy	\$ 102,200	0.0717%	\$ 1,087
Excel Corp.	\$ 35,086	0.0246%	\$ 373
Fag Bearing	\$ 10,630	0.0075%	\$ 113
Farmland Industries	\$ 1,150,669	0.8073%	\$ 12,234
Flint Hills	\$ 2,008	0.0014%	\$ 21
Ford	\$ 11,756	0.0082%	\$ 125
Freedom	\$ 11,876	0.0083%	\$ 126
Gate	\$ 4,297	0.0030%	\$ 46
General Motors	\$ 450,920	0.3184%	\$ 4,794
Granby	\$ 51,582	0.0362%	\$ 549
Greeley Gas Co.	\$ 1,545,712	1.0844%	\$ 16,435
Greeley Gas Co.	\$ 6,301,238	4.4207%	\$ 66,997
Grove Municipal	\$ 570,320	0.4001%	\$ 6,064

**Williams Gas Pipelines Central  
RP93-109 Environmental Cost  
Settlement Allocation**

**Appendix A**

Shipper	12-Mos. Ending Sep 30, 2000 Revenue 1/	Percentage	Allocated Settlement Amount
GS-WRI	\$ 190,596	0.1337%	\$ 2,027
Hamilton	\$ 9,400	0.0066%	\$ 100
Heartland Cemt	\$ 25,983	0.0182%	\$ 276
Howard	\$ 17,429	0.0122%	\$ 185
International Paper	\$ 11,981	0.0084%	\$ 127
Iola	\$ 328,796	0.2307%	\$ 3,496
Jane Phillips Med. Center	\$ 6,956	0.0049%	\$ 74
Kansas City Power & Light	\$ 18,215	0.0128%	\$ 194
Kansas City Power & Light	\$ 971,513	0.6816%	\$ 10,330
Kansas Gas Service	\$ 42,628,863	29.9070%	\$ 453,246
KMGA	\$ 1,143,678	0.8024%	\$ 12,160
Laclede	\$ 2,982,346	2.0923%	\$ 31,710
Lawrence Paper	\$ 29,284	0.0205%	\$ 311
Leann Gas	\$ 174,868	0.1227%	\$ 1,859
Lebo	\$ 20,433	0.0143%	\$ 217
Liberal	\$ 18,902	0.0133%	\$ 201
Manchester Pipeline Corp.	\$ 3,795	0.0027%	\$ 40
Mannford	\$ 108,953	0.0764%	\$ 1,158
Margasco Partnership	\$ 102,422	0.0719%	\$ 1,089
Marshall Municipal Utilities	\$ 5,480	0.0038%	\$ 58
McClouth	\$ 15,326	0.0108%	\$ 163
Midwest United	\$ 76,193	0.0535%	\$ 810
Missouri Gas Energy	\$ 49,677,467	34.8521%	\$ 528,190
Mountain Energy	\$ 603,446	0.4234%	\$ 6,416
Mulberry	\$ 18,740	0.0131%	\$ 199
Nebraska Public Gas Agency	\$ 451,419	0.3167%	\$ 4,800
Nelagoney Rural	\$ 1,650	0.0012%	\$ 18
Neodesha	\$ 99,685	0.0699%	\$ 1,060
Oneok Energy	\$ 2,018,616	1.4162%	\$ 21,463
Orlando	\$ 5,159	0.0036%	\$ 55
Oronogo	\$ 4,734	0.0033%	\$ 50
Ozark Natural	\$ 263,958	0.1852%	\$ 2,807
PG&E Energy Services	\$ 78,408	0.0550%	\$ 834
Pittsburg Coming	\$ 98,467	0.0691%	\$ 1,047
Plattsburg	\$ 119,481	0.0838%	\$ 1,270
Public Srv Co	\$ 16,287	0.0114%	\$ 173
Questar ETC	\$ 346,703	0.2432%	\$ 3,686
Reading	\$ 4,489	0.0031%	\$ 48
Reliant	\$ 4,216	0.0030%	\$ 45
Reliant	\$ 98,749	0.0693%	\$ 1,050
Severy Gas	\$ 11,622	0.0082%	\$ 124
Southern Mo. Gas	\$ 1,052,809	0.7386%	\$ 11,194

**Williams Gas Pipelines Central  
RP93-109 Environmental Cost  
Settlement Allocation**

**Appendix A**

<b>Shipper</b>	<b>12-Mos. Ending Sep 30, 2000 Revenue 1/</b>	<b>Percentage</b>	<b>Allocated Settlement Amount</b>
Talbot Industries	\$ 6,363	0.0045%	\$ 68
Tenaska Mkt	\$ 182,996	0.1284%	\$ 1,946
Terra Nitro LT	\$ 540,000	0.3788%	\$ 5,741
TXU Energy	\$ 6,358	0.0045%	\$ 68
Tyson	\$ 137,095	0.0962%	\$ 1,450
US Gypsum	\$ 196,057	0.1375%	\$ 2,085
US Gypsum	\$ 34,092	0.0239%	\$ 362
Utilicorp Energy	\$ 7,981	0.0056%	\$ 85
Utilicorp United	\$ 7,981,648	5.5997%	\$ 84,864
Viola	\$ 5,188	0.0036%	\$ 55
Vulcan Chemical	\$ 336,926	0.2364%	\$ 3,582
Wakita	\$ 17,044	0.0120%	\$ 181
Wann Public Works	\$ 3,297	0.0023%	\$ 35
WBI Production	\$ 554,724	0.3892%	\$ 5,898
WES	\$ 5,109,095	3.5844%	\$ 54,322
Western Resources	\$ 984,464	0.6907%	\$ 10,467
WFS Company	\$ 289,619	0.2032%	\$ 3,079
Wheaton Natural Gas	\$ 47,770	0.0335%	\$ 508
<b>Totals</b>	<b>\$ 142,537,940</b>	<b>100.0000%</b>	<b>\$ 1,515,517</b>

Net Settlement

\$ 1,515,517

1/ Includes firm transportation and firm storage reservation revenues for the twelve months ended September 30, 2000.

	Cashout	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	Totals
Oct-99	\$0.00	\$320,259.09	\$893.40	\$55,702.59	\$257,527.47	\$0.00	\$46,799.25	\$0.00	\$0.00	\$0.00	\$0.00	\$681,181.80
Nov-99	\$0.00	\$285,872.51	\$1.87	\$56,685.66	\$229,216.28	\$0.00	\$57,365.07	\$270.00	\$0.00	\$0.00	\$0.00	\$629,411.39
Dec-99	\$0.00	\$299,592.47	\$0.00	\$56,883.13	\$238,055.83	\$0.00	\$54,636.86	\$4,034.04	\$0.00	\$4,033.80	\$0.00	\$657,236.13
Jan-00	\$0.00	\$286,124.88	\$0.00	\$62,060.13	\$228,990.81	\$0.00	\$69,639.05	\$2,208.81	\$0.00	\$4,033.80	\$0.00	\$653,057.28
Feb-00	\$0.00	\$299,939.93	\$0.00	\$54,833.06	\$237,178.87	\$0.00	\$59,906.47	(\$221.46)	\$0.00	\$4,033.80	\$0.00	\$655,670.67
Mar-00	\$0.00	\$291,811.28	\$0.00	\$53,092.12	\$230,314.13	\$0.00	\$55,733.17	\$78.58	\$0.00	\$4,033.80	\$0.00	\$635,063.08
Apr-00	\$0.00	\$294,405.44	\$1,196.62	\$54,252.29	\$236,198.22	\$0.00	\$50,396.33	\$285.78	\$0.00	\$0.00	\$0.00	\$636,734.68
May-00	\$0.00	\$288,785.29	\$5,250.95	\$69,780.50	\$232,741.67	\$0.00	\$51,770.73	\$0.00	\$3,211.81	\$0.00	\$0.00	\$651,540.95
Jun-00	\$0.00	\$289,864.76	\$1,285.20	\$57,657.80	\$232,332.44	\$0.00	\$50,850.73	\$3,928.40	\$2,705.18	\$0.00	\$0.00	\$638,624.51
Jul-00	\$0.00	\$286,514.94	\$5,155.89	\$74,070.91	\$228,835.35	\$0.00	\$52,436.05	\$1,266.58	\$1,774.32	\$0.00	\$20,621.80	\$670,675.84
Aug-00	\$0.00	\$282,743.45	\$10,347.47	\$79,557.30	\$227,921.36	\$0.00	\$51,896.46	\$0.00	\$689.11	\$0.00	\$25,137.88	\$678,293.03
Sep-00	\$0.00	\$292,451.80	\$3,773.56	\$59,394.59	\$234,464.18	\$0.00	\$52,101.23	\$0.00	\$151.66	\$0.00	\$18,506.92	\$658,843.94
	\$0.00	\$3,618,365.84	\$27,904.96	\$733,970.08	\$2,813,776.61	\$0.00	\$653,531.40	\$11,860.63	\$8,532.08	\$16,136.20	\$62,266.60	\$7,846,333.30
	0.00%	44.84%	0.36%	9.35%	35.86%	0.00%	8.33%	0.15%	0.11%	0.21%	0.79%	

Williams Check # 500142 Allocation

	Cashout	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	Totals
Williams Check Total	\$84,864.00	\$38,053.77	\$301.81	\$7,938.44	\$30,433.11	\$0.00	\$7,068.43	\$128.17	\$92.28	\$174.51	\$673.46	\$84,864.00

**October 1999 - September 2000 Totals**

Refund Amount	\$ 7,981,648.00
Tracker Amounts	<u>\$ 7,846,333.30</u>
Difference	\$ 135,314.70

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4154									\$ -			\$ -
TA553		\$ 71,049.74		\$ -	\$ 62,028.39		\$ -	\$ -	\$ -			\$ 133,078.13
TA557		\$ 211,790.92	\$ 893.40	\$ 1,341.51	\$ 188,962.37	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 402,988.20
TA588							\$ 178.71					\$ 178.71
TA591							\$ 1,775.46					\$ 1,775.46
TA707							\$ -				\$ -	\$ -
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 8,380.31			\$ 6,536.71							\$ 14,917.02
TA873		\$ -		\$ 54,361.08	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 54,361.08
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 44,845.08	\$ -				\$ 44,845.08
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 29,038.12		\$ -	\$ -			\$ -	\$ -			\$ 29,038.12
POOLS	\$ -											\$ -
	\$ -	\$ 320,259.09	\$ 893.40	\$ 55,702.59	\$ 257,527.47	\$ -	\$ 46,799.25	\$ -	\$ -	\$ -	\$ -	\$ 681,181.80

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4154									\$ -			\$ -
TA553		\$ 59,368.43		\$ -	\$ 51,996.79		\$ -	\$ -	\$ -			\$ 111,365.22
TA557		\$ 193,396.08	\$ 1.87	\$ 5,873.83	\$ 172,269.93	\$ -	\$ 2,674.94	\$ 270.00	\$ -	\$ -	\$ -	\$ 374,486.65
TA588							\$ 168.20					\$ 168.20
TA591							\$ 2,203.34					\$ 2,203.34
TA707							\$ -				\$ -	\$ -
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,872.51			\$ 6,120.54							\$ 13,993.05
TA873		\$ -		\$ 50,811.83	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 50,811.83
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 45,812.97	\$ -				\$ 45,812.97
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 25,235.49		\$ -	\$ (1,170.98)			\$ -	\$ -			\$ 24,064.51
TA1040							\$ 6,505.62					\$ 6,505.62
POOLS	\$ -											\$ -
	\$ -	\$ 285,872.51	\$ 1.87	\$ 56,685.66	\$ 229,216.28	\$ -	\$ 57,365.07	\$ 270.00	\$ -	\$ -	\$ -	\$ 629,411.39

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ 1,117.13			\$ -					\$ 1,436.31		\$ 2,553.44
RA4467		\$ 2,020.27			\$ -					\$ 2,597.49		\$ 4,617.76
TA553		\$ 62,411.75		\$ -	\$ 54,934.09		\$ -	\$ -	\$ -			\$ 117,345.84
TA557		\$ 199,241.87	\$ -	\$ 5,291.99	\$ 176,875.07	\$ -	\$ 905.80	\$ 4,034.04	\$ -	\$ -	\$ -	\$ 386,348.77
TA588							\$ 426.83					\$ 426.83
TA591							\$ 5,191.73					\$ 5,191.73
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,889.28			\$ 6,132.86							\$ 14,022.14
TA873		\$ -		\$ 51,591.14	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 51,591.14
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 41,606.88	\$ -				\$ 41,606.88
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 26,912.17		\$ -	\$ 113.81			\$ -	\$ -			\$ 27,025.98
TA1040							\$ 6,505.62					\$ 6,505.62
POOLS	\$ -											\$ -
	\$ -	\$ 299,592.47	\$ -	\$ 56,883.13	\$ 238,055.83	\$ -	\$ 54,636.86	\$ 4,034.04	\$ -	\$ 4,033.80	\$ -	\$ 657,236.13

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466	\$ 1,093.13									\$ 1,436.31		\$ 2,529.44
RA4467	\$ 2,020.27									\$ 2,597.49		\$ 4,617.76
TA553	\$ 57,393.59				\$ 50,176.79							\$ 107,570.38
TA557	\$ 191,780.06		\$ 10,510.70		\$ 170,752.61			\$ 2,208.61				\$ 385,644.81
TA588							\$ 483.58					\$ 483.58
TA591							\$ 5,958.17					\$ 5,958.17
TA757												
TA840	\$ 6,448.93				\$ 7,573.21							\$ 14,022.14
TA873				\$ 51,549.43								\$ 51,549.43
TA874												
TA883							\$ 46,319.75					\$ 46,319.75
TA956												
TA1006	\$ 27,388.90				\$ 488.20							\$ 27,877.10
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS												
	\$ -											\$ -
	\$ 286,124.88			\$ 62,060.13	\$ 228,990.81		\$ 69,639.05	\$ 2,208.61		\$ 4,033.80		\$ 653,057.28

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ 1,093.13			\$ -					\$ 1,436.31		\$ 2,529.44
RA4467		\$ 2,020.27			\$ -					\$ 2,597.49		\$ 4,617.76
TA553		\$ 62,884.38		\$ -	\$ 54,796.98		\$ -	\$ -	\$ -			\$ 117,681.36
TA557		\$ 199,288.56	\$ -	\$ 3,657.47	\$ 176,230.61	\$ -	\$ 2,982.00	\$ (221.46)	\$ -	\$ -	\$ -	\$ 381,937.18
TA588							\$ 385.41					\$ 385.41
TA591							\$ 4,324.56					\$ 4,324.56
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,869.36			\$ 6,094.59							\$ 13,963.95
TA873		\$ 80.47		\$ 51,175.59	\$ 56.69		\$ -	\$ -	\$ -		\$ -	\$ 51,312.75
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 45,729.78	\$ -				\$ 45,729.78
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 26,703.76		\$ -	\$ -			\$ -	\$ -			\$ 26,703.76
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS	\$ -											\$ -
	\$ -	\$ 299,939.93	\$ -	\$ 54,833.06	\$ 237,178.87	\$ -	\$ 59,906.47	\$ (221.46)	\$ -	\$ 4,033.80	\$ -	\$ 655,670.67

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ 1,093.13			\$ -					\$ 1,436.31		\$ 2,529.44
RA4467		\$ 2,020.27			\$ -					\$ 2,597.49		\$ 4,617.76
TA553		\$ 59,856.23		\$ -	\$ 52,566.35		\$ -	\$ -	\$ -			\$ 112,422.58
TA557		\$ 194,341.72	\$ -	\$ 2,274.21	\$ 171,725.48	\$ -	\$ -	\$ 78.58	\$ -	\$ -	\$ -	\$ 368,419.99
TA588							\$ 273.25					\$ 273.25
TA591							\$ 3,610.71					\$ 3,610.71
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,796.17			\$ 6,022.30							\$ 13,818.47
TA873		\$ -		\$ 50,817.91	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 50,817.91
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 45,364.49	\$ -				\$ 45,364.49
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 26,703.76		\$ -	\$ -			\$ -	\$ -			\$ 26,703.76
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS	\$ -											\$ -
	\$ -	\$ 291,811.28	\$ -	\$ 53,092.12	\$ 230,314.13	\$ -	\$ 55,733.17	\$ 78.58	\$ -	\$ 4,033.80	\$ -	\$ 635,063.08

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ -			\$ -					\$ -		\$ -
RA4467		\$ -			\$ -					\$ -		\$ -
TA553		\$ 65,435.40		\$ -	\$ 57,367.81		\$ -	\$ -	\$ -			\$ 122,803.21
TA557		\$ 196,025.07	\$ 1,196.62	\$ 2,801.77	\$ 173,794.85	\$ -	\$ -	\$ 285.78	\$ -	\$ -	\$ -	\$ 374,104.09
TA588							\$ 292.43					\$ 292.43
TA591							\$ 2,153.05					\$ 2,153.05
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,874.97			\$ 6,085.13							\$ 13,960.10
TA873		\$ 62.59		\$ 51,450.52	\$ 43.59		\$ -	\$ -	\$ -		\$ -	\$ 51,556.70
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 41,466.13	\$ -				\$ 41,466.13
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 25,007.41		\$ -	\$ (1,093.16)			\$ -	\$ -			\$ 23,914.25
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS	\$ -											\$ -
	\$ -	\$ 294,405.44	\$ 1,196.62	\$ 54,252.29	\$ 236,198.22	\$ -	\$ 50,396.33	\$ 285.78	\$ -	\$ -	\$ -	\$ 636,734.68

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ -			\$ -					\$ -		\$ -
RA4467		\$ -			\$ -					\$ -		\$ -
TA553		\$ 63,012.37		\$ 3,524.67	\$ 55,224.69		\$ -	\$ -	\$ 1,630.35			\$ 123,392.08
TA557		\$ 191,176.13	\$ 5,250.95	\$ 11,454.01	\$ 171,387.87	\$ -	\$ -	\$ -	\$ 1,581.46	\$ -	\$ -	\$ 380,850.42
TA588							\$ 118.72					\$ 118.72
TA591							\$ 1,742.73					\$ 1,742.73
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,893.03			\$ 6,129.11							\$ 14,022.14
TA873		\$ -		\$ 54,801.82	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 54,801.82
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 43,424.56	\$ -				\$ 43,424.56
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 26,703.76		\$ -	\$ -			\$ -	\$ -			\$ 26,703.76
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS	\$ -											\$ -
	\$ -	\$ 288,785.29	\$ 5,250.95	\$ 69,780.50	\$ 232,741.67	\$ -	\$ 51,770.73	\$ -	\$ 3,211.81	\$ -	\$ -	\$ 651,540.95

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ -			\$ -					\$ -		\$ -
RA4467		\$ -			\$ -					\$ -		\$ -
TA553		\$ 62,178.09		\$ -	\$ 53,680.10		\$ -	\$ -	\$ -			\$ 115,858.19
TA557		\$ 193,216.69	\$ 1,285.20	\$ 5,419.25	\$ 172,714.99	\$ -	\$ -	\$ 3,928.40	\$ 2,705.18	\$ -	\$ -	\$ 379,269.71
TA588							\$ 114.30					\$ 114.30
TA591							\$ 518.68					\$ 518.68
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,942.28			\$ 6,050.77							\$ 13,993.05
TA873		\$ -		\$ 52,238.55	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 52,238.55
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 43,733.03	\$ -				\$ 43,733.03
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 26,527.70		\$ -	\$ (113.42)			\$ -	\$ -			\$ 26,414.28
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS	\$ -											\$ -
	\$ -	\$ 289,864.76	\$ 1,285.20	\$ 57,657.80	\$ 232,332.44	\$ -	\$ 50,850.73	\$ 3,928.40	\$ 2,705.18	\$ -	\$ -	\$ 638,624.51

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ -			\$ -					\$ -		\$ -
RA4467		\$ -			\$ -					\$ -		\$ -
TA553		\$ 62,807.64		\$ 2,870.76	\$ 53,838.28		\$ -	\$ 1,202.18	\$ -			\$ 120,518.86
TA557		\$ 189,260.56	\$ 5,155.89	\$ 17,558.72	\$ 168,917.91	\$ -	\$ -	\$ 64.40	\$ 1,774.32	\$ -	\$ -	\$ 382,731.80
TA588	Norwich						\$ 113.99					\$ 113.99
TA591	Olivett						\$ 129.09					\$ 129.09
TA707											\$ 20,621.80	\$ 20,621.80
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,942.98			\$ 6,079.16							\$ 14,022.14
TA873		\$ -		\$ 53,641.43	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 53,641.43
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 45,708.25	\$ -				\$ 45,708.25
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 26,703.76		\$ -	\$ -			\$ -	\$ -			\$ 26,703.76
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS	\$ -											\$ -
	\$ -	\$ 286,514.94	\$ 5,155.89	\$ 74,070.91	\$ 228,835.35	\$ -	\$ 52,436.05	\$ 1,266.58	\$ 1,774.32	\$ -	\$ 20,621.80	\$ 670,675.84

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ -			\$ -					\$ -		\$ -
RA4467		\$ -			\$ -					\$ -		\$ -
TA553		\$ 62,503.89		\$ 3,285.21	\$ 54,010.67		\$ -	\$ -	\$ -			\$ 119,799.77
TA557		\$ 185,629.42	\$ 10,347.47	\$ 22,632.04	\$ 168,008.27	\$ -	\$ -	\$ -	\$ 689.11	\$ -	\$ -	\$ 387,306.31
TA588	Norwich						\$ 137.42					\$ 137.42
TA591	Olivett						\$ 825.25					\$ 825.25
TA707											\$ 25,137.88	\$ 25,137.88
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 8,026.51			\$ 5,993.97							\$ 14,020.48
TA873		\$ -		\$ 53,640.05	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 53,640.05
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 44,449.07	\$ -				\$ 44,449.07
TA956		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 26,583.63		\$ -	\$ (91.55)			\$ -	\$ -			\$ 26,492.08
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS	\$ -											\$ -
	\$ -	\$ 282,743.45	\$ 10,347.47	\$ 79,557.30	\$ 227,921.36	\$ -	\$ 51,896.46	\$ -	\$ 689.11	\$ -	\$ 25,137.88	\$ 678,293.03

INVOICE TOTALS	CASHOUT	MPS	MPS-RG3/KCI	MPS-GW	KPS	NORAM	PN	UCU	BPU	UES	WP	TOTAL
RA4466		\$ -			\$ -					\$ -		\$ -
RA4467		\$ -			\$ -					\$ -		\$ -
TA553		\$ 64,671.30		\$ 65.22	\$ 55,698.90		\$ -	\$ -	\$ -	\$ -		\$ 120,435.42
TA557		\$ 193,145.39	\$ 3,773.56	\$ 6,585.74	\$ 172,703.58	\$ -	\$ -	\$ -	\$ 151.66	\$ -	\$ -	\$ 376,359.93
TA588	Norwich						\$ 124.32					\$ 124.32
TA591	Olivett						\$ 952.05					\$ 952.05
TA707											\$ 16,506.92	\$ 16,506.92
TA757		\$ -			\$ -	\$ -	\$ -					\$ -
TA840		\$ 7,931.35			\$ 6,061.70				\$ -			\$ 13,993.05
TA873		\$ -		\$ 52,743.63	\$ -		\$ -	\$ -	\$ -		\$ -	\$ 52,743.63
TA874				\$ -								\$ -
TA883		\$ -			\$ -		\$ 44,540.14	\$ -				\$ 44,540.14
TA958		\$ -			\$ -		\$ -	\$ -				\$ -
TA1006		\$ 26,703.76		\$ -	\$ -			\$ -	\$ -			\$ 26,703.76
TA1040							\$ 6,484.72					\$ 6,484.72
POOLS	\$ -											\$ -
	\$ -	\$ 292,451.80	\$ 3,773.56	\$ 59,394.59	\$ 234,464.18	\$ -	\$ 52,101.23	\$ -	\$ 151.66	\$ -	\$ 16,506.92	\$ 658,843.94

# Enclosure 5A

**MISSOURI PUBLIC SERVICE  
Northern System Gas Refund**

		FIRM	INTERRUPTIBLE	TOTAL
1	<b>Beginning Balance September 2000</b>	\$42,425.99	\$0.00	\$42,425.99
2	<b>Actual Refund to Customers by Month</b>			
3	September 2000	\$116.84	\$0.00	\$116.84
4	October 2000	\$217.31	\$0.00	\$217.31
5	November 2000	\$530.31	\$0.00	\$530.31
6	December 2000	\$5,115.98	\$0.00	\$5,115.98
7	January 2001	\$8,110.16	\$0.00	\$8,110.16
8	February 2001	\$6,720.21	\$0.00	\$6,720.21
9	March 2001	\$6,029.51	\$0.00	\$6,029.51
10	April 2001	\$3,426.82	\$0.00	\$3,426.82
11	May 2001	\$1,165.03	\$0.00	\$1,165.03
12	June 2001	\$865.29	\$0.00	\$865.29
13	July 2001	\$588.11	\$0.00	\$588.11
14	August 2001	<u>\$513.22</u>	<u>\$0.00</u>	<u>\$513.22</u>
15	<b>TOTAL:</b>	<b>\$33,398.79</b>	<b>\$0.00</b>	<b>\$33,398.79</b>
16	<b>(Over)/Under Refund</b>	<b>\$9,027.20</b>	<b>\$0.00</b>	<b>\$9,027.20</b>

17 **Supplier Refunds Sep-00 to Aug-01**  
    None

**TOTAL:**                    **\$0.00**                    **\$0.00**                    **\$0.00**

<b>Balance as of August 31, 2001</b>	<b>\$9,027.20</b>	<b>\$0.00</b>	<b>\$9,027.20</b>
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**Annual Firm Mcf Sales Per GR-93-172:**                    **1,468,777**

**Refund Rate Per Ccf:**                    **\$ -**

MPS proposes to change the refund rate from the present rate of \$0.0289/Mcf to zero/Mcf. The balance ,after September 2001 thru November 2001 refunds have been taken out, will be transfer to the 191 account.

**Missouri Public Service  
Southern System  
Estimated Deferred Carrying Cost Balance (DCCB) Calculation  
2000-2001 ACA Year**

<b>Annual Gas Cost Level</b>	
Gas Cost from Nov 01 ACA calculation	29,361,722
Gas Cost from Nov 00 ACA calculation	12,860,556
Gas Cost from Nov 99 ACA calculation	12,006,410
<b>Average of 3 most recent gas cost calculations</b>	<b>18,076,229</b>
	10%
<b>10% of average annual gas cost threshold</b>	<b>1,807,623</b>

	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Total
<b>Sales Volumes (in Mcf)</b>	83,161	136,511	248,996	578,097	862,955	657,919	580,486	341,937	126,032	101,349	79,342	70,207	3,866,992
<b>Cost of Gas Purchased and Produced</b>	713,842	1,330,835	2,705,016	7,011,665	6,654,369	4,054,173	3,319,118	1,276,641	776,412	538,601	467,514	513,536	29,361,722
<b>PGA - Estimated Annualized Unit Cost of Gas</b>	\$5.4426	\$5.4429	\$5.4615	\$5.6542	\$5.6920	\$5.6941	\$6.0183	\$7.0552	\$7.1820	\$7.1758	\$7.1758	\$7.1758	\$7.1758
<b>Actual Annualized Unit Cost of Gas</b>	<u>8.5839</u>	<u>9.7489</u>	<u>10.8637</u>	<u>12.1289</u>	<u>7.7111</u>	<u>6.1621</u>	<u>5.7178</u>	<u>3.7336</u>	<u>6.1604</u>	<u>5.3143</u>	<u>5.8924</u>	<u>7.3146</u>	<u>7.3146</u>
<b>Difference</b>	-3.1413	-4.3060	-5.4021	-6.4747	-2.0192	-0.4681	0.3005	3.3216	1.0216	1.8615	1.2834	-0.1388	-0.1388
<b>Actual Sales Volumes</b>	83,161	136,511	248,996	578,097	862,955	657,919	580,486	341,937	126,032	101,349	79,342	70,207	
<b>DCCB Monthly Over/(Under) Recovery</b>	(261,230)	(587,819)	(1,345,113)	(3,742,989)	(1,742,463)	(307,947)	174,421	1,135,793	128,750	188,659	101,828	(9,745)	
<b>2000-01 DCCB Yr to Date Over/(Under) Recovery</b>	(261,230)	(849,049)	(2,194,162)	(5,937,151)	(7,679,614)	(7,987,561)	(7,813,140)	(6,677,347)	(6,548,597)	(6,359,938)	(6,258,110)	(6,267,855)	
<b>10% of average annual gas cost threshold</b>	1,807,623	1,807,623	1,807,623	1,807,623	1,807,623	1,807,623	1,807,623	1,807,623	1,807,623	1,807,623	1,807,623	1,807,623	
<b>Absolute Value Rcvry Bal that exceeds threshold</b>	-	-	386,539	4,129,528	5,871,991	6,179,938	6,005,517	4,869,724	4,740,974	4,552,315	4,450,487	4,460,232	
<b>Over/(Und) Rcvry Bal that exceeds 10% threshold</b>	-	-	(386,539)	(4,129,528)	(5,871,991)	(6,179,938)	(6,005,517)	(4,869,724)	(4,740,974)	(4,552,315)	(4,450,487)	(4,460,232)	
<b>Interest at Prime Rate - Wall Street Journal - 1%</b>	8.50%	8.50%	8.50%	8.50%	8.00%	7.50%	7.50%	7.50%	7.50%	7.50%	5.75%	5.75%	
<b>Carrying Costs Refunded/(Collected)</b>	-	-	(2,738)	(29,251)	(39,147)	(38,625)	(37,534)	(30,436)	(29,631)	(28,452)	(21,325)	(21,372)	(278,511)
<b>DCCB Percent of Avg Annual Gas Costs</b>	-1.45%	-4.70%	-12.14%	-32.85%	-42.48%	-44.19%	-43.22%	-36.94%	-36.23%	-35.18%	-34.62%	-34.67%	(109,760)

Note: The DCCB will become 0 at the beginning of each new ACA period (Sep).  
Note: Shaded Area indicates estimate.

**Missouri Public Service  
Northern System  
Estimated Deferred Carrying Cost Balance (DCCB) Calculation  
2000-2001 ACA Year**

	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Total
<b>Annual Gas Cost Level</b>													
Gas Cost from Nov 01 ACA calculation													9,298,567
Gas Cost from Nov 00 ACA calculation													4,634,386
Gas Cost from Nov 99 ACA calculation													5,260,714
Average of 3 most recent gas cost calculations													6,397,889
													10%
10% of average annual gas cost threshold													639,789
<b>Sales Volumes (in Mcf)</b>	22,708	41,831	80,384	223,108	280,594	232,222	208,621	118,577	40,352	29,972	20,405	17,864	1,316,638
<b>Cost of Gas Purchased and Produced</b>	298,218	438,255	853,121	1,728,715	1,866,185	1,392,375	1,183,396	459,027	306,096	275,616	238,613	258,949	9,298,567
<b>PGA - Estimated Annualized Unit Cost of Gas</b>	\$5.8980	\$5.8980	\$5.9209	\$6.2578	\$6.2578	\$6.2578	\$6.5700	\$7.6161	\$7.6899	\$7.6899	\$7.6899	\$7.6899	\$7.6899
<b>Actual Annualized Unit Cost of Gas</b>	<u>13.1327</u>	<u>10.4769</u>	<u>10.6131</u>	<u>7.7483</u>	<u>6.6508</u>	<u>5.9959</u>	<u>5.6725</u>	<u>3.8711</u>	<u>7.5856</u>	<u>9.1958</u>	<u>11.6937</u>	<u>14.4953</u>	
<b>Difference</b>	-7.2347	-4.5789	-4.6922	-1.4905	-0.3930	0.2619	0.8975	3.7450	0.1043	-1.5059	-4.0038	-6.8054	
<b>Actual Sales Volumes</b>	22,708	41,831	80,384	223,108	280,594	232,222	208,621	118,577	40,352	29,972	20,405	17,864	
<b>DCCB Monthly Over/(Under) Recovery</b>	(164,287)	(191,537)	(377,179)	(332,551)	(110,282)	60,826	187,247	444,071	4,208	(45,135)	(81,699)	(121,575)	
<b>2000-01 DCCB Yr to Date Over/(Under) Recovery</b>	(164,287)	(355,824)	(733,003)	(1,065,554)	(1,175,836)	(1,115,010)	(927,763)	(483,692)	(479,483)	(524,619)	(606,318)	(727,892)	
<b>10% of average annual gas cost threshold</b>	639,789	639,789	639,789	639,789	639,789	639,789	639,789	639,789	639,789	639,789	639,789	639,789	
<b>Absolute Value Rcvry Bal that exceeds threshold</b>	-	-	93,214	425,766	536,047	475,221	287,974	-	-	-	-	-	88,103
<b>Over/(Und) Rcvry Bal that exceeds 10% threshold</b>	-	-	(93,214)	(425,766)	(536,047)	(475,221)	(287,974)	-	-	-	-	-	(88,103)
<b>Interest at Prime Rate - Wall Street Journal - 1%</b>	8.50%	8.50%	8.50%	8.50%	8.00%	7.50%	7.50%	7.50%	7.50%	7.50%	5.75%	5.75%	
<b>Carrying Costs Refunded/(Collected)</b>	-	-	(660)	(3,016)	(3,574)	(2,970)	(1,800)	-	-	-	-	(422)	(12,442)
<b>DCCB Percent of Avg Annual Gas Costs</b>	-2.57%	-5.56%	-11.46%	-16.65%	-18.38%	-17.43%	-14.50%	-7.56%	-7.49%	-8.20%	-9.48%	-11.38%	

Note: The DCCB will become 0 at the beginning of each new ACA period (Sep).

Note: Shaded Area indicates estimate.

**Missouri Public Service  
Eastern System  
Estimated Deferred Carrying Cost Balance (DCCB) Calculation  
2000-2001 ACA Year**

	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Total
<b>Annual Gas Cost Level</b>													
Gas Cost from Nov 01 ACA calculation													4,279,552
Gas Cost from Nov 00 ACA calculation													1,927,396
Gas Cost from Nov 99 ACA calculation													1,842,919
<b>Average of 3 most recent gas cost calculations</b>													2,683,289
													10%
<b>10% of average annual gas cost threshold</b>													268,329
<b>Sales Volumes (in Mcf)</b>	7,513	13,342	19,407	53,581	93,616	65,986	57,650	41,324	15,132	10,208	8,150	7,215	393,122
<b>Cost of Gas Purchased and Produced</b>	121,559	173,606	379,996	803,952	1,143,558	510,203	391,767	251,210	155,787	133,257	107,328	107,328	4,279,552
<b>PGA - Estimated Annualized Unit Cost of Gas</b>	\$6.6400	\$6.6400	\$7.2605	\$8.5016	\$8.5016	\$8.5016	\$8.6686	\$10.1402	\$10.3802	\$10.3802	\$10.3802	\$10.3802	\$10.3802
<b>Actual Annualized Unit Cost of Gas</b>	16.1794	13.0120	19.5808	15.0046	12.2154	7.7320	6.7956	6.0791	10.2953	13.0544	13.1699	14.8750	
<b>Difference</b>	-9.5394	-6.3720	-12.3203	-6.5030	-3.7138	0.7696	1.8730	4.0610	0.0849	-2.6742	-2.7897	-4.4948	
<b>Actual Sales Volumes</b>	7,513	13,342	19,407	53,581	93,616	65,986	57,650	41,324	15,132	10,208	8,150	7,215	
<b>DCCB Monthly Over/(Under) Recovery</b>	(71,672)	(85,016)	(239,095)	(348,432)	(347,674)	50,781	107,976	167,817	1,285	(27,298)	(22,735)	(32,432)	
<b>2000-01 DCCB Yr to Date Over/(Under) Recovery</b>	(71,672)	(156,687)	(395,782)	(744,214)	(1,091,889)	(1,041,108)	(933,131)	(765,314)	(764,029)	(791,327)	(814,062)	(846,494)	
<b>10% of average annual gas cost threshold</b>	268,329	268,329	268,329	268,329	268,329	268,329	268,329	268,329	268,329	268,329	268,329	268,329	
<b>Absolute Value Rcvry Bal that exceeds threshold</b>	-	-	127,453	475,885	823,560	772,779	664,802	496,985	495,700	522,998	545,733	578,165	
<b>Over/(Und) Rcvry Bal that exceeds 10% threshold</b>	-	-	(127,453)	(475,885)	(823,560)	(772,779)	(664,802)	(496,985)	(495,700)	(522,998)	(545,733)	(578,165)	
<b>Interest at Prime Rate - Wall Street Journal - 1%</b>	8.50%	8.50%	8.50%	8.50%	8.00%	7.50%	7.50%	7.50%	7.50%	7.50%	5.75%	5.75%	
<b>Carrying Costs Refunded/(Collected)</b>	-	-	(903)	(3,371)	(5,490)	(4,830)	(4,155)	(3,106)	(3,098)	(3,269)	(2,615)	(2,770)	(33,607)
<b>DCCB Percent of Avg Annual Gas Costs</b>	-2.67%	-5.84%	-14.75%	-27.74%	-40.69%	-38.80%	-34.78%	-28.52%	-28.47%	-29.49%	-30.34%	-31.55%	

Note: The DCCB will become 0 at the beginning of each new ACA period (Sep).

Note: Shaded Area indicates estimate.

**Missouri Public Service  
Southern System  
2001-2002 Winter Season Revenue Impact from Winter PGA Filing**

Month	PGA Factor	Month	PGA Factor	PGA Change (11/01)	Revenue Impact (Winter Season)
Nov-00	5.8957	Nov-01	6.5449	0.6492	200,626
Dec-00	5.8957	Dec-01	6.5449	0.6492	370,227
Jan-01	5.8957	Jan-02	6.5449	0.6492	488,121
Feb-01	5.8957	Feb-02	6.5449	0.6492	448,823
Mar-01	5.8957	Mar-02	6.5449	0.6492	328,861

**Estimated Winter Season Change in Revenue** **1,836,659**

**Percent Change Between PGA Factors** **11.01%**

Firm Sales Volume @ Burnertip

3,823,123

Month	Estimated Customer Usage Mcf/Mnth	Estimated % Mcf/Yr	Estimated Company Sales Mcf/Mnth
Jan	23.6	19.67%	751,881
Feb	21.7	18.08%	691,348
Mar	15.9	13.25%	506,564
Apr	9.6	8.00%	305,850
May	5.3	4.42%	168,855
Jun	3.6	3.00%	114,694
Jul	2.8	2.33%	89,206
Aug	2.7	2.25%	86,020
Sep	3	2.50%	95,578
Oct	4.2	3.50%	133,809
Nov	9.7	8.08%	309,036
Dec	<u>17.9</u>	<u>14.92%</u>	<u>570,283</u>
TOTAL	120	100%	3,823,123

Note: Estimated Customer Usage Obtained from Missouri Public Service Commission.



**Missouri Public Service  
Eastern System  
2001-2002 Winter Season Revenue Impact from Winter PGA Filing**

Month	PGA Factor	Month	PGA Factor	PGA Change (11/00)	Revenue Impact (Winter Season)
Nov-00	9.2690	Nov-01	10.8009	1.5319	46,939
Dec-00	9.2690	Dec-01	10.8009	1.5319	86,620
Jan-01	9.2690	Jan-02	10.8009	1.5319	114,202
Feb-01	9.2690	Feb-02	10.8009	1.5319	105,008
Mar-01	9.2690	Mar-02	10.8009	1.5319	76,942

**Estimated Winter Season Change in Revenue                    429,711**

**Percent Change Between PGA Factors                                    16.53%**

Firm Sales Volume @ Burnertip

379,066

Month	Estimated Customer Usage Mcf/Mnth	Estimated % Mcf/Yr	Estimated Company Sales Mcf/Mnth
Jan	23.6	19.67%	74,550
Feb	21.7	18.08%	68,548
Mar	15.9	13.25%	50,226
Apr	9.6	8.00%	30,325
May	5.3	4.42%	16,742
Jun	3.6	3.00%	11,372
Jul	2.8	2.33%	8,845
Aug	2.7	2.25%	8,529
Sep	3	2.50%	9,477
Oct	4.2	3.50%	13,267
Nov	9.7	8.08%	30,641
Dec	<u>17.9</u>	<u>14.92%</u>	<u>56,544</u>
TOTAL	120	100%	379,066

Note: Estimated Customer Usage Obtained from Missouri Public Service Commission.