CASE NUMBER:

99-070

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RECEIVED

DEC 3 1999

PUBLIC SERVICE COMMISSION

December 3, 1999

Ms. Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, KY 40602

Re: Case No. 99-070

Dear Ms. Helton:

Please file the attached Joint Stipulation and Settlement executed by all parties to this case. Attached to the Joint Stipulation and Settlement are Exhibit A, the proposed tariff sheets reflecting the terms and conditions consistent with the terms of the settlement, Exhibit B the proof of revenue calculations and Exhibit C a side by side comparison of existing and stipulated tariffs.

The parties have worked diligently to arrive at this agreement, which resolves all outstanding issues in the case. The rates proposed in the settlement are to become effective for service on and after December 15, 1999. It is hoped that the Commission can review this proposal and if necessary resolve any issues or answer any questions at the hearing scheduled for December 14th.

Western will work with the Staff and Commission to provide any additional information as quickly as possible so that this case can be completed as expeditiously as possible.

Thank you for your assistance, and if there are any questions about this matter or if additional information is needed, please contact me.

Sincerely Yours,

John N. Hughes

John N. Hughes
Attorney for Western Kentucky
Gas Company

cc: Intervenors

RECEIVED
DEC 3 1999
PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE RATE APPLICATION OF WESTERN)
KENTUCKY GAS COMPANY FOR AN) CASE NO. 99-070
ADJUSTMENT OF RATES)

JOINT STIPULATION AND SETTLEMENT

On June 23, 1999, Western Kentucky Gas Company filed an application seeking a general increase in rates. Under the original concept, Western sought an increase in revenue of $14,127,650, which reflects an approximate increase in rates of 11.7%.

The primary factor underlying Western's request for an increase in rates is Western's rate base growth. The growth includes investment in Western's computer systems and information technology for serving customers.

Under the settlement recommendation, Western will reduce its request for a rate increase to $9,940,000, which reflects an approximate increase in rates of approximately 8.24%. This settlement is approximately 30% less than the amount originally requested by Western. Western's last general adjustment in rates was made on March 1, 1996. The recommended increase comports with the general level of inflation since Western's last adjustment in rates.

All of the parties to this proceeding, Western Kentucky Gas Company ("Western"), the Attorney General of the Commonwealth of Kentucky, and WBI Southern, Inc. jointly stipulate and agree that Western should be permitted to adjust its rates to recover $9,940,000 in additional annual revenues effective for service on and after December 15, 1999.

Western's annual revenues at existing rates are $120,587,318 as shown on Revised Exhibit GLS-1, Schedule 1 of 1. The effect of this Stipulation and Settlement is to authorize Western to recover total revenues on an annual basis of $130,527,318 ($120,587,318 + $9,940,000). The additional revenue stipulated is reasonable and the additional $9,940,000 shall be added to Western's rates and allocated among the customer classes as follows: residential rates: $6,238,259 (9.1%); commercial: $2,385,006 (6.9%); industrial: $901,580 (5.4%); other gas revenues: $415,089 (55.0%). The increase authorized is 8.24% to Western's customers based upon the revenue received from its current customers.

All of the parties understand that this Stipulation and Settlement is not binding upon the Public Service Commission of the Commonwealth of Kentucky. The parties do not agree on any specific item of change as requested by Western except as specified herein, nor any specific theory supporting the appropriateness of the changes recommended. Modifications to Western's tariffs are for this case only and are not binding upon any party in any future proceeding.

All of the parties to this proceeding as evidenced by their signatures agree that the increase in rates stipulated is reasonable, viewed in the context of a resolution of Western's case, is in fact a reasonable resolution of all the issues in the proceeding and is fair, just and reasonable to the shareholders and ratepayers of Western.

In summary, the adjustments to Western's proposed rate application are as follows: The proposed premises charge is withdrawn, tariff sheet 67. Western's request for the cost recovery of the demand side management (DSM) pilot program expenses is withdrawn. Western's cost recovery of the three year extension of the DSM program is adopted as proposed, tariff sheets 30a-30c. Western's proposal for a weather normalization adjustment (WNA) is adopted as proposed, tariff sheet 26. The WNA will be implemented as a pilot program for five years. All service charges are adopted as proposed, tariff sheets 51, 65-67. The residential customer charge proposed by Western is adjusted to $7.50. The customer charges applicable to commercial and industrial customers are adjusted to $20.00 and $220.00 respectively. The industrial margin loss recovery mechanism is accepted, but amended to reflect a 50-50 sharing of the lost revenue between shareholders and residential customers, tariff sheet 29L. Western's proposal to bifurcate its commodity charge into a distribution charge and a gas charge is adopted. Further, the parties are not bound by this provision in future cases. Finally, Western will begin filing its gas cost adjustment (GCA) on a quarterly basis beginning with the first quarter following the Commission's adoption of this settlement, tariff sheets 27-29. Western's proposal for a Gas Research Institute Research and Development Rider is adopted.

Western will modify its proposed "T-5" Tariff changing the originally proposed net monthly rate from $0.10 per Mcf to a $50.00 monthly administrative fee per customer, as more fully detailed on Tariff Sheets No. 49 and 50.

Regarding the interconnect of the East Diamond Field into Western's system, WBSI or its subsidiary Kentucky Pipeline and Storage Company ("KYPSCO") would contract for and install facilities in accordance with Western's specifications, and Western agrees to take title to those facilities and to operate and maintain those facilities as more fully detailed in the interconnect agreement to be finalized.

In support of the conclusion of the reasonableness of the increase stipulated, the parties continue to expend time, energy and resources in contesting this matter and the possibility of any request for a rehearing or appeal of the Commission's decision is eliminated.

All of the parties waive cross-examination of all witnesses unless the Commission does not approve this Stipulation and Settlement. The Stipulation and Settlement is agreed to for the purposes of Case No. 99-070 only, and shall not be binding on the parties in any other proceeding before this Commission or any court and it shall not be offered or relied upon in any other proceeding involving Western Kentucky Gas Company or any other utility regulated by the Public Service Commission of the Commonwealth of Kentucky.

If the Public Service Commission adopts this Stipulation and Settlement in its entirety, each of the parties agrees that it shall not file an application for rehearing with the Commission or appeal this case or any part of it to the Franklin Circuit Court.

If the Public Service Commission does not adopt this Stipulation and Settlement in its entirety, each party reserves the right to withdraw from it and to request that this case proceed as if no Stipulation and Settlement had been entered into. In such event, this Stipulation and Settlement shall not be binding upon any of the parties and shall not be admitted into evidence or relied upon in any manner by any of the parties, the Commission or its staff.

Western's proposal, with the changes agreed upon, are acceptable to the parties and reflected in the proposed tariff sheets attached to this Stipulation and Settlement as Attachment A.

Attached to the Stipulation and Settlement as Attachment B is the proof of revenue, showing that the rates set forth in Attachment A will generate no more than the proposed revenue increase to which the parties have agreed.

The parties stipulate and recommend that the Notice of Intent, Notice, Application, testimony, pleadings, responses to data requests and other matters filed in this case shall be admitted into the record and that they provide sufficient evidentiary support for this Stipulation and Settlement.

All the parties agree that this Stipulation and Settlement is reasonable and in the best interest of all concerned and urge the Commission to adopt the Stipulation and Settlement in its entirety.

AGREED TO:

Western Kentucky Gas Company

BY: William J. Senter

TITLE: Vice President - Rates & Regulatory Affairs

DATE: December 2, 1999

Attorney General's Office of Rate Intervention

BY: [illegible]

TITLE: Assistant Attorney General

DATE: December 3, 1999

WBI Southern, Inc.

BY: Robert W[illegible]

TITLE: Counsel for WBI Southern, Inc.

DATE: 12/2/99

EXHIBIT A

WESTERN KENTUCKY GAS COMPANY

Rate Book Index

WESTERN KENTUCKY GAS COMPANY

Rate Book Index

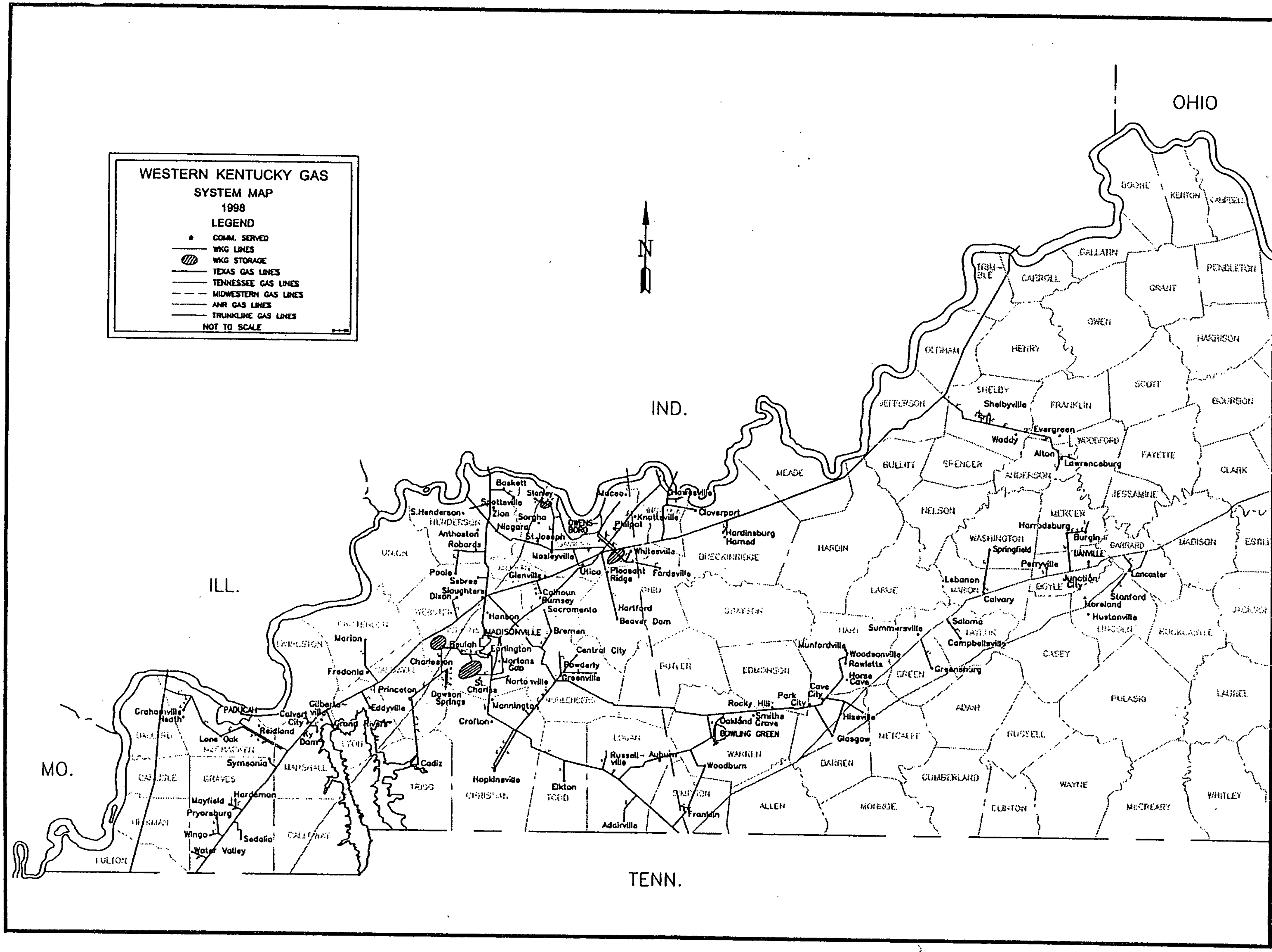
The following pages have been reserved for future use: 8-10, 14, 33, 39, 53-60 (T)

WESTERN KENTUCKY GAS COMPANY

Towns and Communities in Service Area

The Service Area of the Company includes the following towns and their environs:

Adairville	Dennis	Hartford	Munfordsville	Sebree	
Aetnaville	Depoy	Hawesville	Niagara	Sedalia	(N)
Alton	Dermont	Heath	Nortonville	Shelby City	
Anthoston	Dixon	Hendron	Oak Ridge	Shelbyville	
Anton	Earlington	Herbert	Oakdale	Slaughters	(N)
Auburn	Eddyville	Hickory	Oakland	Smiths Grove	
Baskett	Elkton	Hill-n-dale	Oklahoma	Sorgho	
Beadlestown	Ellmitch	Hiseville	Owensboro	So. Henderson	(N)
Beaver Dam	Empire	Hopkinsville	Paducah	So. Highland	
Beda	Epley	Horse Cave	Park City	So. Union	
Beulah	Epperson	Hustonville	Perryville	Spottsville	
Boston	Evergreen	Junction City	Philpot	Springfield	
Bowling Green	Farmdale	Knottsville	Pleasant Hill	St. Charles	
Bremen	Fearsville	Lake City	Pleasant Ridge	St. Joseph	
Briartown	Feliciana	Lancaster	Plum Springs	Stanford	
Browns Valley	Finley	Lawrenceburg	Poole	Stanley	
Buck Creek	Fordsville	Lebanan	Powderly	Stringtown	
Buford	Franklin	Livia	Princeton	Summersville	
Burgin	Fredonia	Logantown	Pritchardsville	Sutherland	
Cadiz	Fruit Hill	Lone Oak	Pryorsburg	Symsonia	
Calhoun	Gilbertsville	Luzerne	Reidland	Thurston	
Calvert City	Gishton	Maceo	Reidville	Utica	
Calvary	Glasgow	Madisonville	Reynolds Sta.	Waddy	(N)
Campbellsville	Glenville	Mannington	Robards	Water Valley	
Carbondale	Grahamville	Marion	Rocky Hill	West Louisville	
Cave City	Grand Rivers	Masonville	Rome	Whitesville	
Central City	Greensberg	Mayfield	Rowletts	Wingo	
Charleston	Greenville	McGowan	Rumsey	Woodburn	
Cloverport	Habit	Memphis Junc.	Russellville	Woodlawn	
Crayne	Hanson	Midland	Sacramento	Woodsonville	
Crofton	Hardeman	Milledgeville	Salmons	Yelvington	
Danville	Hardinsburg	Moreland	Saloma	Zion	
Dawson Springs	Harned	Mortons Gap	Schochoh		
Deanfield	Harrodsburg	Mosleyville			


WESTERN KENTUCKY GAS
SYSTEM MAP
1998
LEGEND
COMM. SERVED
WKG LINES
WKG STORAGE
TEXAS GAS LINES
TENNESSEE GAS LINES
MIDWESTERN GAS LINES
ANR GAS LINES
TRUNKLINE GAS LINES
NOT TO SCALE
N
OHIO
IND.
ILL.
MO.
TENN.
PADUCAH
MADISONVILLE
OWENSBORO
BOWLING GREEN
DANVILLE
Hopkinsville
Henderson
Princeton
Glasgow
Lebanon
Harrodsburg
Lawrenceburg
Shelbyville
Campbellsville
Greensburg
Central City
Greenville
Russellville
Mayfield

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-seventh SHEET No. 4
Cancelling
Seventy-sixth SHEET No. 4

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary

Case No. 99-070

Firm Service

Base Charge:

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

Rate per Mcf[2]	Sales (G-1)	Transport (T-2)	Carriage (T-4)	(T)
First 300[1] Mcf	@ $4.6455 per Mcf	@ $1.9086 per Mcf	@ $1.1900 per Mcf	(I,I,I)
Next 14,700[1] Mcf	@ 4.1145 per Mcf	@ 1.3776 per Mcf	@ 0.6590 per Mcf	(I,I,I)
Over 15,000 Mcf	@ 3.8855 per Mcf	@ 1.1486 per Mcf	@ 0.4300 per Mcf	(I,I,I)

High Load Factor Firm Service

HLF demand charge/Mcf @ $4.2945 @ $4.2945 per Mcf of daily Contract Demand

Rate per Mcf[2]			(T)
First 300[1] Mcf	@ $4.0888 per Mcf	@ $1.3519 per Mcf	(I,I)
Next 14,700[1] Mcf	@ 3.5578 per Mcf	@ 0.8209 per Mcf	(I,I)
Over 15,000 Mcf	@ 3.3288 per Mcf	@ 0.5919 per Mcf	(I,I)

Interruptible Service

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

Rate per Mcf[2]	Sales (G-2)	Transport (T-2)	Carriage (T-3)	(T)
First 15,000[1] Mcf	@ $3.4590 per Mcf	@ $0.7221 per Mcf	@ $0.5300 per Mcf	(I,I,I)
Over 15,000 Mcf	@ 3.2881 per Mcf	@ 0.5512 per Mcf	@ 0.3591 per Mcf	(I,I,I)

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

2 DSM, GRI and MLR Riders may also apply, where applicable. (N)

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-seventh SHEET No. 5
Cancelling
Seventy-sixth SHEET No. 5

WESTERN KENTUCKY GAS COMPANY

Current Gas Cost Adjustments
Case No. 99-070

Applicable

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

Gas Charge = GCA (D)

GCA = EGC + CF + RF + PBRRF

Gas Cost Adjustment Components	G-1	HLF G-1	G-2	
EGC (Expected Gas Cost Component)	$3.6999	$3.1432	$3.1432	(N)
CF (Correction Factor)	(0.2239)	(0.2239)	(0.2239)	
RF (Refund Adjustment)	(0.0452)	(0.0452)	(0.0150)	
PBRRF (Performance Based Rate Recovery Factor)	0.0247	0.0247	0.0247	
GCA (Gas Cost Adjustment)	$3.4555	$2.8988	$2.9290	(N)

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Current Transportation and Carriage
Case No. 99-070

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

System Lost and Unaccounted gas percentage: **1.9%**

			Distribution Charge		Non Commodity		Transportation Charge	(T)
Transportation Service (T-2)[1]								
a) Firm Service								
First 300 [2]	Mcf	@	$1.1900	+	$0.7186	=	$1.9086 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6590	+	0.7186	=	1.3776 per Mcf	(I)
Over 15,000 [2]	Mcf	@	0.4300	+	0.7186	=	1.1486 per Mcf	(I)
b) High Load Factor Firm Service (HLF)								
Demand		@	$0.0000	+	4.2945	=	$4.2945 per Mcf of daily contract demand	
First 300 [2]	Mcf	@	$1.1900	+	$0.1619	=	$1.3519 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6590	+	0.1619	=	0.8209 per Mcf	(I)
Over 15,000	Mcf	@	0.4300	+	0.1619	=	0.5919 per Mcf	(I)
c) Interruptible Service								
First 15,000 [2]	Mcf	@	$0.5300	+	$0.1921	=	$0.7221 per Mcf	(I)
All Over 15,000	Mcf	@	0.3591	+	0.1921	=	0.5512 per Mcf	(I)
Carriage Service[3]								
a) Firm Service (T-4)								
First 300 [2]	Mcf	@	$1.1900	+	$0.0000	=	$1.1900 per Mcf	(I)
Next 14,700 [2]	Mcf	@	0.6590	+	0.0000	=	0.6590 per Mcf	(I)
Over 15,000 [2]	Mcf	@	0.4300	+	0.0000	=	0.4300 per Mcf	(I)
b) Interruptible Service (T-3)								
First 15,000 [2]	Mcf	@	$0.5300	+	$0.0000	=	$0.5300 per Mcf	(I)
All Over 15,000	Mcf	@	0.3591	+	0.0000	=	0.3591 per Mcf	(I)

1 Includes standby sales service under corresponding sales rates. GRI Rider may also apply. (T)

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

3 Excludes standby sales service.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

1. Applicable

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. Availability of Service

Available for any use for individually metered service, other than auxiliary or standby service (except for hospitals or other uses of natural gas in facilities requiring emergency power, however, the rated input to such emergency power generators is not to exceed the rated input of all other gas burning equipment otherwise connected multiplied by a factor equal to 0.15) at locations where suitable service is available from the existing distribution system and an adequate supply of gas to reader service is assured by the supplier(s) of natural gas to the Company.

3. Net Monthly Rate

a) Base Charge (I)
$ 7.50 per meter for residential service (I)
$20.00 per meter for non-residential service (T)

b) Distribution Charge (I)

First[1]	300 Mcf	@	$1.1900 per 1,000 cubic feet	(I)
Next[1]	14,700 Mcf	@	0.6590 per 1,000 cubic feet	(I)
Over	15,000 Mcf	@	0.4300 per 1,000 cubic feet	

(N)

c) Weather Normalization Adjustment, referenced on Sheet No. 26.

(T)

d) Gas Cost Adjustment (GCA) Rider, referenced on Sheet No. 27.

(N)

e) Margin Loss Recovery Rider, referenced on Sheet No. 29L.

(N)

f) Demand Side Management Cost Recovery Mechanism, referenced on Sheet No. 30a.

(N)

g) Gas Research Institute R&D Rider, referenced on Sheet No. 30d.

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

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, Distribution Charge, the Gas Cost Adjustment (GCA) Rider, and other riders applicable by class of service. (T)

5. **Minimum Monthly Bill**

The Base Charge plus any High Load Factor (HLF) demand charge, if applicable. (T,D)

6. **Service Period**

Open order. However, the Company may require a special written contract for large use or abnormal service requirements. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting firm service customers in the area.

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service

Rate G-1

7. **Late Payment Charge**

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for services rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

8. **Rules and Regulations** (T)

Service furnished under this schedule is subject to the Company's Rules and Regulations and to applicable rate and rider schedules.

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

a) Available on an individually metered service basis to commercial and industrial customers for any use as approved by the Company on a strictly interruptible basis, subject to suitable service being available from the existing transmission and/or distribution facilities and when an adequate supply of gas is available to the Company under its purchase contracts with its pipeline supplier.

b) The supply of gas provided for herein shall be sold primarily on an interruptible basis, however, in certain cases and under certain conditions the contract may include High Priority service to be billed under "General Sales Service Rate G-1" limited to use and volume which, in the Company's judgement, requires and justifies such combination service.

c) The contract for service under this rate schedule shall include interruptible service or a combination of High Priority service and Interruptible service, however, the Company reserves the right to limit the volume of High Priority service available to any one customer.

3. **Delivery Volumes** (T,N)

a) The volume of gas to be sold and purchases under this rate schedule shall be set forth in a written contract, specifying a maximum daily interruptible sales service volume and shall be subject to revision in accordance with the Company's approved curtailment plan.

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

b) High Priority Service
The volume for High Priority service shall be established on a High Priority Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive in any one day, subject to other provisions of this rate schedule and the related contract.

c) Interruptible Service
The volume for Interruptible service shall be established on an Interruptible Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive subject to other provisions of this rate schedule and the related contract.

d) Revision of Delivery Volumes
The Daily Contract Demand for High Priority service and the Daily Contract Demand for Interruptible service shall be subject to revision as necessary so as to coincide with the customer's normal operating conditions and actual load with consideration given to any anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

4. Net Monthly Rate

a) Base Charge: $220.00 per delivery point per month (I)
Minimum Charge: The Base Charge plus any Transportation Fee and EFM facilities charge

b) Distribution Charge: (T)

High Priority Service
The volume of gas used each day up to, but not exceeding the effective High Priority Daily Contract Demand shall be totaled for the month and billed at the "General Firm Sales Service Rate G-1".

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service

Rate G-2

Interruptible Service

Gas used per month in excess of the High Priority Service shall be billed as follows:

First 15,000 Mcf	$0.5300 per 1,000 cubic feet	(I)
Over 15,000 Mcf	0.3591 per 1,000 cubic feet	(I)

c) Gas Cost Adjustment (GCA) Rider, referenced on Sheet No. 26. (N)

d) Margin Loss Recovery Rider, referenced on Sheet No. 29L. (D)

e) Demand Side Management Cost Recovery Mechanism, referenced on Sheet No. 30a. (N)

f) Gas Research Institute R&D Rider, referenced on Sheet No. 30d. (N)

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

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

(D)

5. **Standby or Auxiliary Equipment and Fuel** (T)

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries. (D)

6. **Alternative Fuel Responsive Flex Provision** (N)

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable rate on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

(D)
(T)

7. **Curtailment**

(C)

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God, strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

8. **Penalty for Unauthorized Overruns** (N)

a) In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

b) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

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

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

9. Special Provisions (T)

a) A written contract with a minimum term of one year shall be required.

b) The Rules and Regulations and Orders of the Public Service Commission and of the Company and the Company's general terms and conditions applicable to industrial and commercial sales, shall apply to this rate schedule and all contracts thereunder.

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

10. Late Payment Charge (T)

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

1. Applicable

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. Availability of Service

Available to any customer (with an expected demand of at least 36,500 Mcf per year) where usage is individually metered at locations where suitable service is available from the existing distribution system and an adequate supply of gas to render service is assured by the supplier(s) of natural gas to the Company. Except as provided in the service agreement, LVS service is not available in conjunction with any other tariffed gas service.

3. Net Monthly Rate

a) Base Charge:

LVS-1 Service	$ 20.00 per Meter	(I)
LVS-2 Service	220.00 per Meter	(I)
Combined Service	220.00 per Meter	(I)

b) Distribution Charge for LVS-1 Service (T)

First[1]	300 Mcf	@	$1.1900 per Mcf	(I)
Next[1]	14,700 Mcf	@	0.6590 per Mcf	(I)
Over	15,000 Mcf	@	0.4300 per Mcf	(I)

c) Distribution Charge for LVS-2 Service (T)

First[1]	15,000 Mcf	@	$0.5300 per Mcf	(I)
Over	15,000 Mcf	@	0.3591 per Mcf	(I)

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

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ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

d) The Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) The Weighted Average Commodity Gas Cost is based on current purchase costs including all related variable delivery costs for the billing period for which the gas was delivered.

f) The True-Up Adjustment shall be customer account specific and shall include all prior period adjustments known at time of billing.

g) Notice of the Weighted Average Commodity Gas Cost and True-Up Adjustment will be filed with the Commission prior to billing.

h) Margin Loss Recovery Rider, referenced on Sheet No. 29L. (N)

4. **Net Monthly Bill** (T)

The Net Monthly Bill shall be equal to the sum of the Base Charge, the High Load Factor demand charge, the Distribution Charge, the Non-Commodity Component, the Weighted Average Commodity Gas Cost and the True-Up Adjustment.

5. **Minimum Monthly Bill** (T,D)

The Base Charge and High Load Factor demand charge, if applicable.

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

(D)

6. Standby or Auxiliary Equipment and Fuel

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

7. Alternative Fuel Responsive Flex Provision (LVS-2 Service Only) (T)

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable distribution charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the applicable Distribution Charge to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component and weighted average commodity gas cost of the customer's otherwise applicable rate. (T)

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales

Rates LVS-1 (High Priority), LVS-2 (Low Priority)

8. **Curtailment** (N)

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God, strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

9. **Penalty for Unauthorized Overruns** (N)

a) In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

b) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

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

10. **Service Agreement**

The Company will require a written contract for a minimum term of twelve months. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting service of equal or higher priority customers in the area. (D)

A customer with an unexpired contract for other services may subscribe to LVS service by contract amendment provided the contract, as amended, has a remaining term of at least twelve months.

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

The volume of gas to be sold and purchased under this rate schedule and the related contract shall be established on a daily, monthly and seasonal basis. The priority of contract volumes shall be subject to revision in accordance with the Company's approved curtailment plan.

The contract volumes (or service mix) shall be subject to revision by the Company as appropriate so as to coincide with the customer's normal operating conditions and actual load with consideration give to any reasonably anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

11. Late Payment Charge (T)

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

12. Exit Fee (T)

When service under this schedule is discontinued, the customer is responsible for (or entitled to) an exit fee (or refund) equal to the lagging true-up adjustments related to the customer's service period.

13. Rules and Regulations (T)

Service furnished under this schedule and applicable contracts are subject to the Company's Rules and Regulations and to applicable rate and rider schedules.

WESTERN KENTUCKY GAS COMPANY

Weather Normalization Adjustment Rider

WNA (N)

1. **Applicable**

Applicable to Rate G-1 Sales Service, excluding industrial class only.

The distribution charge per Mcf for gas service as set forth in G-1 Sales Service shall be adjusted by an amount hereinunder described as the Weather Normalization Adjustment (WNA). The WNA shall be applicable to Rate G-1 Sales Service, excluding Industrial Sales Service.

For a five year period commencing on November 1, 2000, the WNA shall apply to all residential, commercial and public authority bills based on meters read during the months of November through April. The WNA shall increase or decrease accordingly by month. The WNA will not be billed to reflect meters read during the months of May through October. Customer base loads and heating sensitivity factors will be determined by class and computed annually.

2. **Computation of Weather Normalization Adjustment**

The WNA shall be computed using the following formula:

$$WNA_i = R_i \frac{(HSF_i \quad (NDD - ADD))}{(BL_i + (HSF_i \times ADD))}$$

Where:

i	=	any rate schedule or billing classification within a rate schedule that contains more than one billing classification
WNA_i	=	Weather Normalization Adjustment Factor for the ith rate schedule or classification expressed as a rate per Mcf
R_i	=	weighted average rate (distribution charge) of temperature sensitive sales for the ith schedule or classification
HSF_i	=	heat sensitive factor for the ith schedule or classification
NDD	=	normal billing cycle heating degree days
ADD	=	actual billing cycle heating degree days
BL_i	=	base load for the ith schedule or classification

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ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Weather Normalization Adjustment Rider

WNA (N)

1. Applicable

Applicable to Rate G-1 Sales Service, excluding industrial class only.

The distribution charge per Mcf for gas service as set forth in G-1 Sales Service shall be adjusted by an amount hereinunder described as the Weather Normalization Adjustment (WNA). The WNA shall be applicable to Rate G-1 Sales Service, excluding Industrial Sales Service.

For a five year period commencing on November 1, 2000, the WNA shall apply to all residential, commercial and public authority bills based on meters read during the months of November through April. The WNA shall increase or decrease accordingly by month. The WNA will not be billed to reflect meters read during the months of May through October. Customer base loads and heating sensitivity factors will be determined by class and computed annually.

2. Computation of Weather Normalization Adjustment

The WNA shall be computed using the following formula:

$$WNA_i = R_i \frac{(HSF_i \quad (NDD - ADD)\ )}{(BL_i + \quad (HSF_i \times ADD)\ )}$$

Where:

i	=	any rate schedule or billing classification within a rate schedule that contains more than one billing classification
WNA_i	=	Weather Normalization Adjustment Factor for the ith rate schedule or classification expressed as a rate per Mcf
R_i	=	weighted average rate (distribution charge) of temperature sensitive sales for the ith schedule or classification
HSF_i	=	heat sensitive factor for the ith schedule or classification
NDD	=	normal billing cycle heating degree days
ADD	=	actual billing cycle heating degree days
BL_i	=	base load for the ith schedule or classification

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ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

1. **Applicable**

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

2. **Gas Cost Adjustment (GCA)**

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

3. **Determination of GCA** (T)

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

GCA = EGC + CF + RF

Where:

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

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

EGC is composed of the following:

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

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

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

Less

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

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

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

7) The cost of Company-use volumes.

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

(D)

Gas Cost Adjustment
Rider GCA

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

The Company shall file an updated Correction Factor (CF) in its April and October GCA filings, to become effective in May and November respectively. The April filing shall update the CF for the six months ended January while the October filing shall update the CF for the six months ended July. [1] (T)

RF - is the sum of any Refund Factors filed in the current and three preceding quarterly filings. The current Refund Factor reflects refunds received from suppliers during the reporting period. The Refund Factor will be determined by dividing the refunds received plus estimated interest[2], by the annual sales used in the quarterly filing less transported volumes. After a refund factor has remained in effect for twelve months, the difference in the amount received and the amount refunded plus the accrued interest[2] will be rolled into the next refund calculation. The refund account will be operated independently of the CF and only added as a component to the GCA in order to obtain a net GCA. In the event of any large or unusual refunds, the Company may apply to the Commission for the right to depart from the refund procedure herein set forth. (T)

[1] The April GCA filing effective May 2000 shall update the CF for the seven months ended January 2000 to account for the change in methodology ordered in Case No. 99-070. (N)

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

4. High Load Factor (HLF) Option

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

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

WESTERN KENTUCKY GAS COMPANY

Margin Loss Recovery Rider

MLR (N)

1. Applicable

Applicable to tariff Sales Service Rates G-1, G-2, LVS-1 and LVS-2. This Margin Loss Recovery Rider is intended to authorize the Company to recover 50% of distribution charge losses that result from (1) discounts pursuant to the Alternate Fuel Responsive Flex Provision, (2) special contracts approved by the Public Service Commission of Kentucky, or (3) a customer's bypass of the Company's system.

2. Calculation of the Margin Loss Recovery Factor

The Margin Loss Recovery Factor will be calculated in accordance with the following formula:

$$MLR = \frac{(ML_f + ML_s + ML_b) \times .5}{S}$$

Where:

MLR is the Margin Loss Recovery Factor

ML_f is the sum of discounts pursuant to the Alternate Fuel Responsive Flex Provision, calculated by multiplying the discount below the customer's otherwise applicable distribution charge times the volumes delivered under the flex provision.

ML_s is the sum of discounts pursuant to special contracts implemented subsequent to Case 99-070, calculated by multiplying the discount below the customer's otherwise applicable distribution charge times the customer's volumes in the test year for Case 99-070 or the customer's current annual volumes (whichever is less).

ML_b is the sum of margin losses associated with customer bypass of the Company's system subsequent to Case 99-070, equaling the total margin attributable to the customer during the test year for Case 99-070.

S is the expected sales volumes as used in the Correcting Factor of the Gas Cost Adjustment Rider

Filing with the Public Service Commission of Kentucky

The MLR shall be filed every January and July, to become effective in February and August, respectively. The February filing shall update the MLR for the six months ended November period while the August filing shall update the MLR for the six months ended May period.

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism

DSM (N)

1. Applicable

Applicable to Rate G-1 Sales Service, residential class only.

The Distribution Charge under Residential Rate G-1 Sales Service, shall be increased or decreased for three annual periods beginning January 2000 by the DSM Cost Recovery Component (DSMRC) at a rate per Mcf in accordance with the following formula:

$$DSMRC = DCRC + DBA$$

Where:

DCRC = DSM Cost Recovery-Current. The DCRC shall include all projected costs for the next twelve-month period. These costs shall be limited to expected payments to program implementation contractors over that period, as well as any costs incurred by or on behalf of the DSM collaborative process. These costs would be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DCRC.

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism
DSM

(N)

DBA = DSM Balance Adjustment. The DBA shall be calculated on a calendar year basis and be used to reconcile the difference between the amount of revenues actually billed through the DCRC and previous applications of the DBA, and the revenues which should have been billed.

The DBA for the upcoming twelve-month period shall be calculated as the sum of the balance adjustments for the DCRC and DBA. For the DCRC, the balance adjustment shall be the difference between the amount billed in a twelve-month period from the application of the DCRC unit charge and the actual cost of the DSM Program during the same twelve-month period.

For the DBA, the balance adjustment shall be the difference between the amount billed in a twelve-month period from the application of the DBA unit charge and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts calculated will include interest to be calculated at a rate equal to the average of "3-month Commercial Paper Rate" for the immediately preceding twelve-month period. The balance adjustments plus interest shall be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DBA.

The Company will file modifications to the DSMRC on an annual basis at least two months prior to the beginning of the effective upcoming twelve-month period for billing. This annual filing shall include detailed calculations of the DCRC and the DBA, as well as data on the total cost of the DSM Program over the twelve-month period.

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism
DSM

(N)

DSM Cost Recovery Component (DSMRC):

DSM Cost Recovery – Current:	$0.0155 per Mcf
DSM Balance Adjustment:	$0.0000 per Mcf
DSMRC Residential Rate G-1	$0.0155 per Mcf

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ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Gas Research Institute R & D Rider

GRI R & D Unit Charge (N)

Applicable:
This rider applies to the distribution charge applicable to all gas transported by the Company other than Rate T-3 and T-4 Carriage Service.

GRI R&D Unit Charge:
The intent of the Gas Research Institute R&D Unit Charge is to maintain the Company's level of contribution per Mcf as of December 31, 1998. The Unit Charge will be billed according to the transition schedule outlined in the pipelines' tariff.

	Rate Per Mcf
GRI R&D Unit Charge	$0.0004

Note 1: The GRI R&D Unit Charge is a weighted average of the rates under the pipelines' transition schedules and applicable annual volumes.

Waiver Provision:
The GRI R&D Unit Charge may be reduced or waived for one or more classifications of service or rate schedules at any time by the Company by filing notice with the Commission. Any such waiver shall not increase the GRI R&D Unit Charge to the remaining classifications of service or rate schedules without Commission approval.

Remittance of Funds:
All funds collected under this rider will be remitted to Gas Research Institute on a monthly basis. The amounts so remitted shall be reported to the Commission annually.

Reports to the Commission:
A statement setting forth the manner in which the funds remitted have been invested in research and development will be filed with the Commission annually.

Termination of this Rider:
Participation in the GRI R&D funding program is voluntary on the part of the Company. This rider may be terminated at any time by the Company by filing a notice of recision with the Commission.

WESTERN KENTUCKY GAS COMPANY

General Transportation Service (T)
Rate T-2

1. **Applicable**

Entire service area of the Company to any customer receiving service under the General Sales Service (G-1) and/or Interruptible Sales Service (G-2).

2. **Availability of Service** (T)

Available to any customer with an expected consumption of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require transportation by the Company to the customer's facilities subject to suitable service being available from existing facilities.

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, there will be applied:

a) Transportation Administration Fee - $50.00 per customer per month (I)

b) Distribution Charge for High Priority Service (T)

First[1]	300	Mcf	@	$ 1.1900	per	Mcf	(I)
Next[1]	14,700	Mcf	@	0.6590	per	Mcf	(I)
Over	15,000	Mcf	@	0.4300	per	Mcf	(I)

c) Distribution Charge for Low Priority Service

First[1]	15,000	Mcf	@	$ 0.5300	per	Mcf	(I)
Over	15,000	Mcf	@	0.3591	per	Mcf	(R)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

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

WESTERN KENTUCKY GAS COMPANY

General Transportation Service (T)

Rate T-2

4. **Net Monthly Bill**

The Net Monthly Bill, for T-2 Service, shall be equal to the sum of the Transportation Administration Fee and the appropriate Transportation Charge (Distribution Charge plus Non-commodity component) applied to the customer's transported volumes and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 7 "Special Provisions" of this tariff). The customer will also be billed for purchases and the applicable Base Charge and High Load Factor (HLF) demand charge under Rates G-1 and G-2. (T)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The Level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

WESTERN KENTUCKY GAS COMPANY

General Transportation Service	(T)
Rate T-2	

b) It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving transportation under this Transportation Tariff Rate (additional facilities may be required to allow for changing from weekly or monthly meter readings to daily meter record for the billing period). Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charges (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 300 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

8. Terms and Conditions

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

b) Gas transported under this Transportation Tariff Rate is subject to the provisions of the Company's curtailment order.

c) The Company will not be obligated to deliver a total supply of gas to the customer in excess if the customer's maximum contracted volumes.

d) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas transported under this Transportation Tariff Rate to the facilities of the Company.

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

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

WESTERN KENTUCKY GAS COMPANY

General Transportation Service	(T)
Rate T-2	

9. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

WESTERN KENTUCKY GAS COMPANY

(D)

Reserved for Future Use

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EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3 (T)

1. **Applicable**

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

2. **Availability of Service**

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require interruptible carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

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

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge - $220.00 per delivery point (I)
b) Transportation Administration Fee - 50.00 per customer per month (I)

c) Distribution Charge for Interruptible Service (T)

First[1]	15,000	Mcf	@	$0.5300 per Mcf	(I)
Over	15,000	Mcf	@	0.3591 per Mcf	(R)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

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

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WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service	(T)
Rate T-3	(T)

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Distribution Charge and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 8 "Special Provisions" of this tariff.) (T)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service	(T)
Rate T-3	

6. Imbalances

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities.

$$\text{Imbalance} = [\, \text{Mcf}_{\text{Customer}} \times (1 - \text{L\&U\%}) \,] - \text{Mcf}_{\text{Company}}$$

Where:

1. "$\text{Mcf}_{\text{Customer}}$" are the total volumes that the customer had delivered to the Company's facilities.

2. "$\text{Mcf}_{\text{Company}}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.

3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer-will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-2). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff. (N,T)

   If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)

Rate T-3

b) "Cash out" Method

Imbalance volumes		**Cash-out Price**
First 5%[1] of $Mcf_{Customer}$	@	100% of Index Price[2]
Next 5%[1] of $Mcf_{Customer}$	@	90% of Index Price[2]
Over 10%[1] of $Mcf_{Customer}$	@	80% of Index Price[2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty (s) assessed by the pipeline (s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "$MCF_{Company}$", on a monthly basis at .10/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service	(T)
Rate T-3	

7. **Curtailment**

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

b) All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission.

8. **Special Provisions**

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Interruptible Carriage Service Rate T-3. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing (T) the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charge (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above.

(D)

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel.

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service	(T)
Rate T-3	

9. **Terms and Conditions**

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

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

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

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

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

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)

Rate T-3

g) The customer will be solely responsible to correct, any imbalances it has caused on the applicable pipeline's system.

10. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)

Rate T-3

11. Alternative Fuel Responsive Flex Provisions

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 46
Cancelling
First Revised SHEET No. 46

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

1. **Applicable**

Entire Service Area of the Company to any customer for that portion of the customer's firm requirements not included under one of the Company's sales tariffs.

2. **Availability of Service**

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require firm carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

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

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge - $220.00 per delivery point (I)

b) Transportation Administration Fee - 50.00 per customer per month (I)

c) Distribution Charge for Firm Service (T)

First[1]	300	Mcf	@	$1.1900	per Mcf	(I)
Next[1]	14,700	Mcf	@	0.6590	per Mcf	(I)
Over	15,000	Mcf	@	0.4300	per Mcf	(I)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charges, if applicable (Sheet No. 51).

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

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Distribution Charge and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see subsection 8 "Special Provisions" of this tariff.) (T)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)

Rate T-4

6. Imbalances

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities.

$$\text{Imbalance} = [\, \text{Mcf}_{\text{Customer}} \text{ X } (1\text{-L\&U\%})\,] - \text{Mcf}_{\text{Company}}$$

Where:

1. "$\text{Mcf}_{\text{Customer}}$" are the total volumes that the customer had delivered to the Company's facilities.

2. "$\text{Mcf}_{\text{Company}}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.

3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-1). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and may be billed at $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff.

   If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)

Rate T-4

b) "Cash out" Method

Imbalance volumes		**Cash-out Price**
First [1] 5% of Mcf $_{Customer}$	@	100% of Index Price [2]
Next [1] 5% of Mcf $_{Customer}$	@	90% of Index Price [2]
Over [1] 10% of Mcf $_{Customer}$	@	80% of Index Price [2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the pipeline(s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "MCF $_{Company}$", on a monthly basis at .10/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)

Rate T-4

7. **Curtailment**

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God; strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

8. **Special Provisions**

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Firm Carriage Service Rate T-4. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric (T) and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charges (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (D)

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel.

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)

Rate T-4

9. Terms and Conditions

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

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

c) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas under this Firm Carriage Service Rate to the facilities of the Company. (T)

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

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

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

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

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

10. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

11. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised Sheet No. 49
Cancelling
Orginal Sheet No. 49

WESTERN KENTUCKY GAS COMPANY

(N)

Alternate Receipt Point Service
Rate T-5

1. **Applicable**
   Entire service area of the Company to any customer, subject to limitations noted below, for that portion of the customer's Rate T-2 transportation or carriage service (Rate T-3 or Rate T-4) requirements.

2. **Availability of Service**
   a) Available, subject to restrictions noted below, to any customer utilizing transportation or carriage services, on an individual service at the same premise, who has purchased its own supply of natural gas and requests delivery to the Company at a receipt point other than the Company's interconnection with the pipeline, or supplier immediately upstream of customer's premises, or the receipt point designated as the primary receipt point in such customer's contract with the Company.
   b) The alternate receipt point through which service is requested must be physically accessible via the Company's existing pipeline system upstream of the delivery point to the customer's facilities.
   c) The Company shall determine the portions of its system to which access may be granted to a specific Alternate Receipt Point.
   d) Access to certain alternate receipt points may be limited or restricted altogether by the Company.
   e) Availability of service is contingent upon the Company's determination that such service is available through existing facilities.
   f) The Company may decline to initiate service to a customer under this tariff, if in the Company's judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

3. **Net Monthly Rate**
   In addition to any and all charges assessed by other parties, and in addition to the charges applicable to Customer associated with their Rate T-2 transportation or Rate T-4 carriage service requirements, the following supplemental administrative charge will be applied during months in which volumes are received and transported from the Alternate Receipt Point:

   a) Administrative Charge @ $50.00 per month

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Alternate Receipt Point Service	(N)
Rate T-5	

The administrative fee is waived if, during the month, the Alternate Receipt Point represents the only point of receipt utilized by the customer.

4. Imbalances
   a) Volumes delivered by the Company under the Alternate Receipt Point service may be subjected to imbalance restrictions additional to those specified in the transportation (Rate T-2) or carriage (Rate T-3 or Rate T-4) tariffs.
   b) Banking or Parking allowances for volumes delivered under the Alternate Receipt Point service may be limited or restricted altogether, at the Company's judgment.

5. Terms and Conditions
   a) Volumes under the Alternate Receipt Point service are received for redelivery by the Company on a strictly interruptible basis.
   b) The Company is not responsible for any costs incurred by the customer in its arrangement for gas supply or capacity to the Alternate Receipt Point.
   c) Specific details relating to volume, receipt point(s) and similar matters shall be covered by a separate written contract or amendment with the customer.
   d) Other than provisions referenced herein, or as more specifically set forth in the contract or amendment with the customer, all provisions of the customer's transportation (Rate T-2) or carriage (Rate T-3 or Rate T-4) tariffs shall apply.

WESTERN KENTUCKY GAS COMPANY

Special Charges

Service	After Hours	Regular	
Meter Set*	$35.00	$28.00	(N)
Turn-on*	25.00	20.00	(N,I)
Read	14.00	12.00	(N)
Reconnect Delinquent Service	40.00	34.00	(N,I)
Seasonal Charge	73.00	65.00	(N)
Special Meter Reading Charge	N/A	No Charge	
Meter Test Charge	N/A	20.00	
Returned Check Charge	N/A	23.00	(I)
Late Payment Charge (Rate G-1 only)		5%	(N)

Optional Facilities Charge for Electronic Flow Measurement ("EFM") equipment
- Class 1 EFM equipment (less than $7,500, including installation costs) 105.00 per mo.
- Class 2 EFM equipment (more than $7,500, including installation costs) 245.00 per mo. (N)

* Waived for qualified low income applicants ("LIHEAP participants")

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

4. Billings

a) The following is an example of the monthly bills sent to the Company's residential customers:

WESTERN KENTUCKY GAS

A DIVISION OF ATMOS ENERGY CORPORATION

Direct Billing & Customer Service Inquiries to
WESTERN KY GAS 1-800-954-4321 (TOLL FREE)
EMERGENCY TELEPHONE 1-800-482-8429 (TOLL FREE)

BILL DATE: 09/07/99 CUSTOMER NO. 000012345
SERVICE ADDRESS: 123 Fourth Street, Owensboro, KY

DATE OF SERVICE FROM	DATE OF SERVICE TO	METER READING PRESENT	METER READING PREVIOUS	USAGE IN CCF	RATE CODE	PRESSURE FACTOR
10/01/99	11/01/99 ❸	564 ❷	564 ❷	❹ 0 EST ❿	42WR ❶	

Western Kentucky Gas is working hard to improve the services we provide to you, our valued customer. Please see the enclosed insert 'The Basics of the New Bill', which explains the new bill design and how it provides you with the information that you need in an easy to understand format. Call us toll free, 24 hours a day, 7 days a week.

Thank you for choosing natural gas, the most comfortable and efficient energy available.

IF BILL IS NOT PAID BY DUE DATE, A PENALTY (IF APPLICABLE) WILL APPEAR ON YOUR NEXT BILL

Comparative Usage	Monthly Usage CCF	Billing Days
This Year	0	31
Last Year	0	31

PREVIOUS BALANCE		00.00
PAYMENT RECEIVED	00.00	
CURRENT GAS CHARGE TOTAL		00.00
CUSTOMER CHARGE	00.00	
DISTRIBUTION CHARGE @ .00000/CCF	00.00	
GAS COST CHARGE @ .00000/CCF	00.00	
SCHOOL FEE @ .00000	00.00	
FRANCHISE FEE @ .00000/CCF	00.00	
❼ ADJUSTMENTS		00.00
SERVICE CHARGE		00.00
TAX TOTAL		00.00
STATE TAX	00.00	
CURRENT CHARGES		00.00
TOTAL AMOUNT DUE		00.00

RETAIN THIS PART FOR YOUR RECORDS - THIS BILL MAY NOT REFLECT RECENT PAYMENTS — SEE REVERSE SIDE FOR EXPLANATION

☐ INDICATE CHANGE OF ADDRESS
02

In order to speed payment processing, please write your account number on your check/money order & do not fold or staple payment to remittance stub. When paying in person, present both parts of bill

40-0000123455-0123456-7
ACCOUNT NUMBER LE9K I ❾

WESTERN KENTUCKY GAS
PO BOX 15448
AMARILLO, TX 79105

PRIOR AMOUNT DUE	TOTAL AMOUNT DUE	DUE DATE
$ 00.00	❻ $ 00.00	11/13/99

Please Indicate Amount of Your Payment: $☐☐☐☐☐☐☐☐

Thank you for choosing.

John Q. Customer
123 Fourth Street
Owensboro, KY 42301

WESTERN KENTUCKY GAS
PO BOX 660654
DALLAS, TX 75266-0654

1. Class of Service (Please See Sheet No. 7)
2. Present and Last Preceding Meter Reading
3. Date of Present Reading
4. Number of Units Consumed
5. Meter Constant If Any - Not Applicable to Residential Service
6. Net Amount for Service Rendered
7. Any Adjustments
8. Gross Amount of Bill - Not Applicable to Residential Service
9. Date After Which a Penalty May Apply
10. Indicates an Estimated or Calculated Bill

NOTE: Large Volume Commercial and Industrial Billing Will Display the Above Information, but May be Presented in a Different Format.

Rules and Regulations

e) The Company will issue to every customer from whom a deposit is collected a receipt of deposit. The receipt will show the name of the customer, location of the service or customer, account number, date, and amount of deposit. If the deposit amount changes, the Company will issue a new receipt of deposit to the customer.

f) Except for Winter Hardship Reconnections (as provided by Section 12 of these Rules and Regulations) customer service may be refused or discontinued if payment of requested deposit is not made.

g) Interest will accrue on all deposits at a rate prescribed by law, beginning on the date of deposit. Interest accrued will be refunded to the customer or credited to the customer's bill on an annual basis, except that the Company will not be required to refund or credit interest on deposits if the customer's bill is delinquent on the anniversary of the deposit date. If interest is paid or credited to the customer's bill prior to twelve (12) months from the date of deposits, the payment or credit shall be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill with any remainder refunded to the customer.

When a deposit is required from a customer it will be held for twelve (12) months, or until service is discontinued, unless one of the following has occurred: (a) service has been terminated for non-payment of services or (b) the customer has been late on two (2) or more payments in the last twelve (12) months.

6. Special Charges

The Company may make special nonrecurring charges, approved by the Commission, to recover customer-specific costs incurred to benefit specific customers. Listed below are the special charges included in the Company's tariff and a short description of the related service performed or action taken by the Company. See the Special Charges, Sheet No. 51 for the amount of the charge.

a) Meter Set. A meter set charge may be assessed for a new service or re-set, or temporary service. (N)

b) Turn On. A turn on charge may be assessed for connecting service which has been terminated or idle at a given premises for reasons other than nonpayment of bills or violation of the Company or Commission regulations. (T)

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

c) Read. A read charge may be assessed for the establishment of new service where only a meter read is required. (N)

d) Reconnect Delinquent Service. A reconnect delinquent service charge may be assessed to reconnect a service which has been terminated for nonpayment of bills or violation of the Company or Commission regulations. Customers qualifying for service reconnection under Section 12 of these Rules and Regulations shall be exempt from reconnect charges. (T)

e) Seasonal Charge. A seasonal charge may be assessed when the customer's service has been disconnected at his request and at any time subsequently within (12) months is reconnected at the same or any other premises. (N)

f) After Hours Charge. An additional charge shall be applied to any special service activity, including reconnects for delinquent service, initiated at the customer's request outside normal business hours such as at night, on weekends or holidays. The Company shall advise the customer of the applicable after hours charge upon initiation of the service request and offer the customer the alternative to perform the requested activity during normal business hours, including reconnects for delinquent service, as a means to avoid the after hours charge. (N)

g) Special Meter Reading Charge. This charge may be assessed when a customer requests that a meter be reread and the second reading shows that the original reading was correct. No charge shall be assessed if the original reading was incorrect. This charge may also be assessed when a customer who reads his own meter fails to read the meter for three (3) consecutive months, and it is necessary for a Company representative to make a trip to read the meter.

(No such charge may be assessed until the amount of the charge is approved or otherwise accepted by the Commission).

h) Meter Resetting Charge. A charge may be assessed for resetting a meter if the meter has been removed at the customer's request.

i) Meter Test Charge. This charge may be assessed if a customer requests the meter be tested pursuant to Section 13 and 807 KAR 5:006, section 18, and the tests show the meter is not more than two (2) percent fast. No charge shall be made if the test shows the meter is more than two (2) percent fast.

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

j) Returned Check Charge. A returned check charge may be assessed if a check accepted for payment of a Company bill is not honored by the customer's financial institution.

k) Late Payment Charge. A late payment charge may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received will first be applied to the bill for services rendered. Additional penalty charges will not be assessed on unpaid penalty charges.

7. Customer Complaints to the Company

Upon complaint to the Company by a customer at the Company's office, by telephone, or in writing, the Company will make a prompt and complete investigation and advise the complainant of its findings. If a written complaint or a complaint made in person at the Company's office is not resolved, the Company will provide written notice to the complainant of his right to file a complaint with the Commission, and will provide him with the address and telephone number of the Commission. If a telephone complaint is not resolved, the Company will provide at least oral notice to the complainant of his right to file a complaint with the Commission and the address and telephone number of the Commission.

8. Bill Adjustments

a) If upon periodic test, request test, or complaint test, a meter in service is found to be more than two (2) percent fast, additional tests shall be made to determine the average error of the meter. The test will be made in accordance with Commission regulations applicable to the type of meter involved.

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C,T)

e) The customer's piping extending from the outlet of the meter shall be installed and maintained by the customer at his expense.

f) The customer shall notify the Company promptly of any leaks in the transmission line or equipment, also, of any hazards or damages to same.

g) Customers may be required to send in monthly meter readings to the Company on suitable forms provided by the Company.

19. Owners Consent

In case the customer is not the owner of the premises where service is to be provided, it will be the customer's responsibility to obtain from the property owner or owners the necessary consent to install and maintain in or on said premises all such piping and other equipment as are required or necessary for supplying gas service to the customer whether the piping and equipment be the property of the customer or the Company.

The Company will not require a prospective customer to obtain easements or rights-of-way on property not owned by the prospective customer as a condition for providing service. The cost of obtaining easements or rights-of-way will be included in the total per foot cost of an extension, and will be apportioned according to Section 28 in these Rules and Regulations.

20. Customer's Equipment and Installation

a) The customer shall furnish, install and maintain at his expense the necessary customer's service line extending from the Company's service connection at the curb or property line to the building or place of utilization of the gas.

b) The installation of the customer's service line shall be made in accordance with the requirement of the constituted authorities and the Company's specifications covering locations, installation, kind and size of pipe, type of pipe coating or wrapping, and method of connecting the joints of pipe. The location shall be the point of easiest access to the Company from its facilities and the Company shall be consulted and its approval obtained before the installation is made.

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(T)

27. Point of Delivery of Gas

The point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of the Company's service connection in to the customer's service line or pipe or at the outlet of the meter, whichever is nearest the delivery main of the Company.

28. Distribution Main Extensions

a) The Company will extend an existing distribution main up to one hundred (100) feet for each single customer provided the following criteria is met:

1) The existing main is of sufficient capacity to properly supply the additional customer(s);

2) Provided that the customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,

3) Provided the potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

b) Whenever an extension exceeds one hundred (100) feet per customer, the Company will enter into an agreement with the customer(s) or subscriber(s). The agreement will provide for the extension on a cost per foot basis with the additional amount to be deposited with the Company by the customer(s) or subscriber(s). The agreement will contain provisions for a proportionate and equitable refund in the event other customers are connected to the extension within a ten (10) year period. Refunds shall be made only after the customer(s) has used gas service for a minimum continuous period of one (1) year. The Company reserves the right to determine the length of the extension, to specify the pipe size and location of the extension, and to construct the extension in accordance with its standard practices. Title to all extensions covered by agreements shall be and remain in the Company and in no case shall the amount of any refunds exceed the original deposit. Any further or lateral extension shall be treated as a new and separate extension.

33. Curtailment Order

In cases of impairment of gas supply or distribution system capacity, or partial or total interruptions and when it appears that the Company is, or will be, unable to supply the requirements of all of its customers in any system or segment thereof, the Company shall curtail gas service to its customers in the manner set forth below. (T)

a) Definitions:

Residential – Service to customers for residential purposes including housing complexes and apartments.

Commercial – Service to customers engaged primarily in the sale of goods or services including institutions and local and federal agencies for uses other than those involving manufacturing.

Industrial – Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product, including the generation of electric power for sale.

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

b) Priorities of Curtailment:

Sales Service

The Company may curtail or discontinue sales service in whole or in part on a daily, monthly or seasonal basis in any purchase zone in accordance with the following priorities, starting with Priority 8 and proceeding in descending numerical order.

High Priority

Priority 1. Residential and services essential to the public health where no alternate fuel exists (Rate G-1)

Priority 2. Small commercials less than 50 Mcf per day (Rate G-1).

Priority 3. Large commercials over 50 Mcf per day not included under lower priorities (Rates G-1, LVS-1)

Priority 4. Industrials served under Rate G-1 or LVS-1.

Low Priority

Priority 5. Customers served under Rates G-2 or LVS-2 other than boilers included in Priority 6.

Priority 6. Boiler loads shall be curtailed in the following order (Rates G-2 or LVS-2).

A – Boilers over 3,000 Mcf per day.
B – Boilers between 1,500 Mcf and 3,000 Mcf per day.
C – Boilers between 300 Mcf and 1,500 Mcf per day.

Priority 7. Imbalance sales service under Rate T-3 and Rate T-4.

Priority 8. Flex sales transactions.

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(T)

c) Penalty for Unauthorized Overruns

In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

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

d) Discontinuance of Service

The Company shall have the right, after reasonable notice to discontinue the gas supply of any customer that fails to comply with a valid curtailment order.

EXHIBIT B

Western Kentucky Gas Company
Summary of Revenue at Present and Proposed Rates
Test Year Ending 12/31/2000

			Test Year Ending 12/31/00 [1]					
Line No.	Description	Block (Mcf)	Number of Bills, Units	Volumes	Present Margin	Present Revenue	Proposed Margin	Proposed Revenue
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Sales							
2	Firm Sales (G-1, LVS-1)	Customer Chrg	1,901,828		$5.10	$9,699,323	$7.50	$14,263,710
3		Customer Chrg	238,063		13.60	3,237,657	20.00	4,761,260
4		0 - 300		19,298,496	1.0615	20,485,353	1.1900	22,965,210
5		301 - 15,000		1,954,863	0.5585	1,091,791	0.6590	1,288,255
6		Over 15,000		8,819	0.4085	3,603	0.4300	3,792
7	Interruptible Sales (G-2, LVS-2)	Customer Chrg	398		150.00	59,700	220.00	87,560
8		0 - 15,000		1,073,178	0.4936	529,721	0.5300	568,784
9		Over 15,000		249,353	0.3436	85,678	0.3591	89,543
10	Overrun (T-4)	0 - 300		0	1.1677	-	1.3090	-
11		301 - 15,000		0	0.6144	-	0.7249	-
12		Over 15,000		0	0.4494	-	0.4730	-
13	Overrun (T-3)	0 - 15,000		0	0.5430	-	0.5830	-
14		Over 15,000		0	0.3780	-	0.3950	-
15	Transportation							
16	Customer Charges (T2/G1)	Customer Chrg	[2]		13.60		20.00	
17	Customer Charges (T2/G2,T4,T3)	Customer Chrg	1,419		150.00	212,850	220.00	312,180
18	Transp. Adm. Fee	Customer Chrg	1,835		45.00	82,575	50.00	91,750
19	Parked Volumes [3]			526,520	0.10	52,652	0.10	52,652
20	Alternate Receipt Point (T-5) [3]						50.00	10,000
21	Firm Transport (G-1)	0 - 300		30,707	1.0615	32,595	1.1900	36,541
22		301 - 15,000		476,920	0.5585	266,360	0.6590	314,290
23		Over 15,000		78,311	0.4085	31,990	0.4300	33,674
24	Interruptible Transport (G-2)	0 - 15,000		556,822	0.4936	274,847	0.5300	295,116
25		Over 15,000		89,758	0.3436	30,841	0.3591	32,232
26	Firm Carriage (T-4)	0 - 300		273,388	1.0615	290,201	1.1900	325,332
27		301 - 15,000		3,352,762	0.5585	1,872,518	0.6590	2,209,470
28		Over 15,000		221,017	0.4085	90,285	0.4300	95,037
29	Interruptible Carriage (T-3)	0 - 15,000		4,656,555	0.4936	2,298,476	0.5300	2,467,974
30		Over 15,000		2,633,087	0.3436	904,729	0.3591	945,542
31	Total Special Contracts [1,4]		156	13,332,103		1,692,428		1,692,428
32	Total Tariff		2,143,699	48,286,139		43,326,173		52,942,332
33	Additional Contract Reformations [1,5]					(1,016,013)		(1,107,327)
34	Other Revenue					755,000		1,170,089
35								
36	Total Revenue, excluding gas costs					43,065,160		53,005,094
37								
38	Gas Costs					77,522,158		77,522,158
39	TOTAL REVENUE					120,587,318		130,527,252
40								

41 [1] Reference Exhibit GLS-1 (Revised as of 11/15/99)
42 [2] Number of Bills included in G-1 Sales.
43 [3] Parked Volumes and Alternate Receipt Point Billing Units not included in Total Deliveries.
44 [4] Information on individual Special Contracts is confidential.
45 [5] Discount from present/proposed rates respectively. Based on confidential information.

EXHIBIT C

Present

For Entire Service Area
P.S.C. NO. 20
Third Revised SHEET No. 1
Cancelling
Second Revised SHEET No. 1

WESTERN KENTUCKY GAS COMPANY

Rate Book Index

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System Map	-	
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Large Volume Sales (LVS-1, LVS-2)	21 to 25	
Gas Cost Adjustment (GCA)	27 to 29	
Experimental Performance Bases Rate Mechanism (PBR)	29a to 29k	(N)
Transportation Service		
Storage Transportation Service (T-1)	31 to 32	
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PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE
DEC 20 1998
PURSUANT TO 807 KAR 5:011
SECTION 9 (1)
BY: [signature]
FOR THE COMMISSION

ISSUED: November 10, 1998 EFFECTIVE: December 20, 1998

ISSUED BY: [signature] Vice President - Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised SHEET No. 1
Cancelling
Third Revised SHEET No. 1

WESTERN KENTUCKY GAS COMPANY

Rate Book Index

	Sheet No.	
General Information		
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Sales Service		
General Firm Sales Service (G-1)	11 to 13	
Interruptible Sales Service (G-2)	15 to 20	
Large Volume Sales (LVS-1, LVS-2)	21 to 25	
Weather Normalization Adjustment (WNA)	26	(N)
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Experimental Performance Based Rate Mechanism (PBR)	29A to 29K	
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ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. NO. 20
Third Revised SHEET No. 2
Cancelling
Second Revised SHEET No. 2

WESTERN KENTUCKY GAS COMPANY

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11.	Company's Refusal or Termination of Service	71 to 74	(N)
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PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

DEC 20 1998

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Stephan O Bell
SECRETARY OF THE COMMISSION

The following pages have been reserved for future use: 8-10, 14, 26, 30, 33, 39, 49, 50, 53-60

ISSUED: November 19, 1998 EFFECTIVE: December 20, 1998

ISSUED BY: William J Senter Vice President - Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised SHEET No. 2
Cancelling
Third Revised SHEET No. 2

WESTERN KENTUCKY GAS COMPANY

Rate Book Index

Rules and Regulations

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The following pages have been reserved for future use: 8-10, 14, 33, 39, 53-60 (T)

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 3
Cancelling
P.S.C. No. 19
Original SHEET No.29

WESTERN KENTUCKY GAS COMPANY

Towns and Communities In Service Area

The Service Area of the Company includes the following towns and their environs:

Adairville	Dermont	Hawesville	Munfordsville	Sebree
Aetnaville	Dixon	Heath	Niagara	Sedalia
Alton	Earlington	Hendron	Nortonville	Shelby City
Anthoston	Eddyville	Herbert	Oak Ridge	Shelbyville
Auburn	Elkton	Hickory	Oakdale	Slaughters
Baskett	Ellmitch	Hill-n-dale	Oakland	Smiths Grove
Beaver Dam	Empire	Hiseville	Oklahoma	Sorgho
Beda	Epley	Hopkinsville	Owensboro	So.Henderson
Beulah	Epperson	Horse Cave	Paducah	So. Highland
Boston	Evergreen	Hustonville	Park City	So. Union
Bowling Green	Farmdale	Junction City	Perryville	Spottsville
Bremen	Fearsville	Knottsville	Philpot	Springfield
Briartown	Feliciana	Lake City	Pleasant Hill	St. Charles
Browns Valley	Finley	Lancaster	Pleasant Ridge	St. Joseph
Buck Creek	Fordsville	Lawrenceburg	Plum Springs	Stanford
Buford	Franklin	Lebanon	Poole	Stanley
Burgin	Fredonia	Livia	Powderly	Stringtown
Cadiz	Fruit Hill	Logantown	Princeton	Summersville
Calhoun	Gilbertsville	Lone Oak	Pritchardsville	Sutherland
Calvert City	Gishton	Luzerne	Pryorsburg	Symsonia
Calvery	Glasgow	Maceo	Reidland	Thurston
Campbellsville	Glenville	Madisonville	Reidville	Utica
Carbondale	Grahamville	Mannington	Reynolds Sta.	Waddy
Cave City	Grand Rivers	Marion	Robards	Water Valley
Central City	Greensburg	Masonville	Rocky Hill	West Louisville
Charleston	Greenville	Mayfield	Rome	Whitesville
Cloverport	Habit	McGowan	Rowletts	Wingo
Crayne	Hanson	Memphis Junc.	Rumsey	Woodburn
Crofton	Hardeman	Midland	Russellville	Woodlawn
Danville	Hardinsburg	Milledgeville	Sacramento	Woodsonville
Dawson Springs	Harned	Moreland	Salmons	Yelvington
Deanfield	Harrodsburg	Mortons Gap	Saloma	Zion
Dennis	Hartford	Mosleyville	Schochoh	

ISSUED: September 4, 1992

EFFECTIVE: March 4, 1993

ISSUED BY: Mary S. Lash

Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 3
Cancelling
Original SHEET No. 3

WESTERN KENTUCKY GAS COMPANY

Towns and Communities In Service Area

The Service Area of the Company includes the following towns and their environs:

Adairville	Dennis	Hartford	Munfordsville	Sebree	
Aetnaville	Depoy	Hawesville	Niagara	Sedalia	(N)
Alton	Dermont	Heath	Nortonville	Shelby City	
Anthoston	Dixon	Hendron	Oak Ridge	Shelbyville	
Anton	Earlington	Herbert	Oakdale	Slaughters	(N)
Auburn	Eddyville	Hickory	Oakland	Smiths Grove	
Baskett	Elkton	Hill-n-dale	Oklahoma	Sorgho	
Beadlestown	Ellmitch	Hiseville	Owensboro	So. Henderson	(N)
Beaver Dam	Empire	Hopkinsville	Paducah	So. Highland	
Beda	Epley	Horse Cave	Park City	So. Union	
Beulah	Epperson	Hustonville	Perryville	Spottsville	
Boston	Evergreen	Junction City	Philpot	Springfield	
Bowling Green	Farmdale	Knottsville	Pleasant Hill	St. Charles	
Bremen	Fearsville	Lake City	Pleasant Ridge	St. Joseph	
Briartown	Feliciana	Lancaster	Plum Springs	Stanford	
Browns Valley	Finley	Lawrenceburg	Poole	Stanley	
Buck Creek	Fordsville	Lebanon	Powderly	Stringtown	
Buford	Franklin	Livia	Princeton	Summersville	
Burgin	Fredonia	Logantown	Pritchardsville	Sutherland	
Cadiz	Fruit Hill	Lone Oak	Pryorsburg	Symsonia	
Calhoun	Gilbertsville	Luzerne	Reidland	Thurston	
Calvert City	Gishton	Maceo	Reidville	Utica	
Calvary	Glasgow	Madisonville	Reynolds Sta.	Waddy	(N)
Campbellsville	Glenville	Mannington	Robards	Water Valley	
Carbondale	Grahamville	Marion	Rocky Hill	West Louisville	
Cave City	Grand Rivers	Masonville	Rome	Whitesville	
Central City	Greensburg	Mayfield	Rowletts	Wingo	
Charleston	Greenville	McGowan	Rumsey	Woodburn	
Cloverport	Habit	Memphis Junc	Russellville	Woodlawn	
Crayne	Hanson	Midland	Sacramento	Woodsonville	
Crofton	Hardeman	Milledgeville	Salmons	Yelvington	
Danville	Hardinsburg	Moreland	Saloma	Zion	
Dawson Springs	Harned	Mortons Gap	Schochoh		
Deanfield	Harrodsburg	Mosleyville			

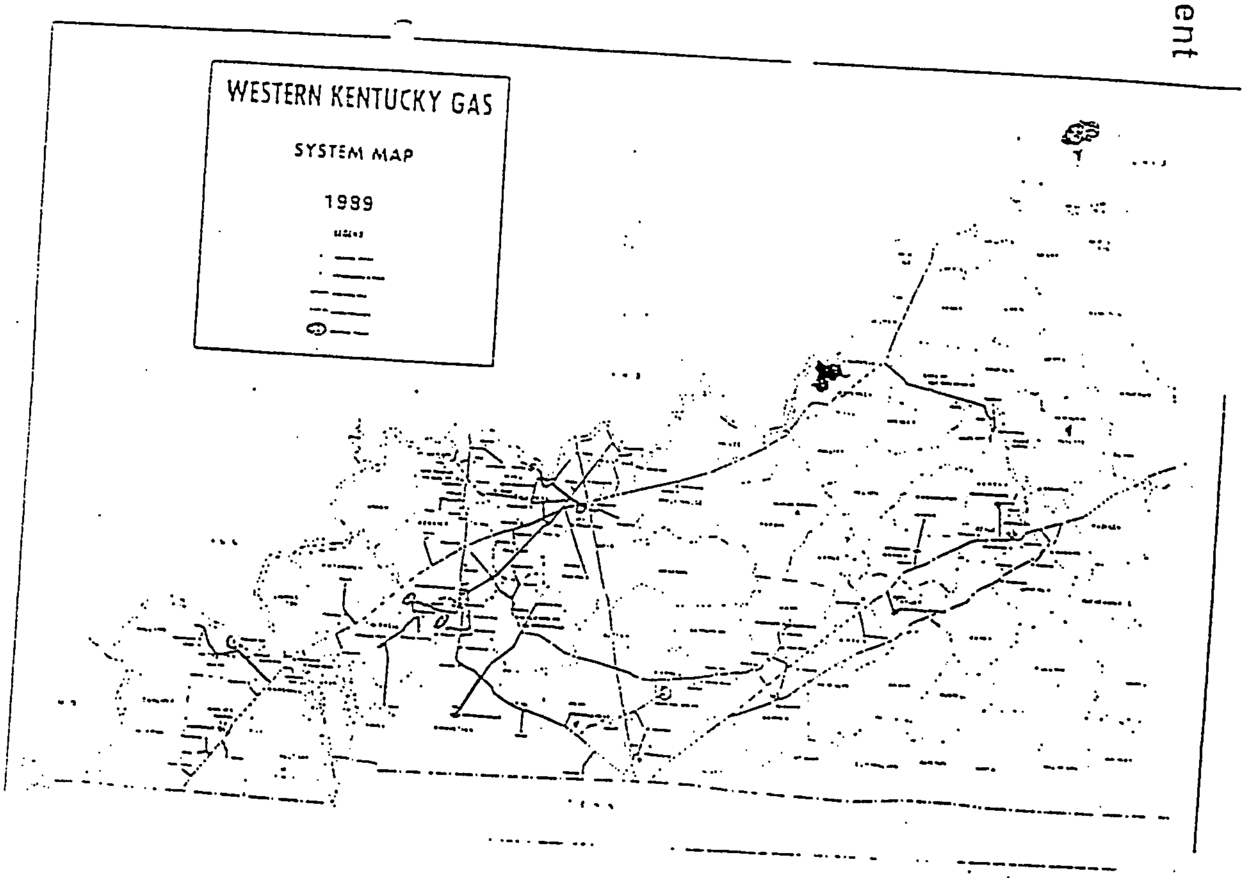
ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

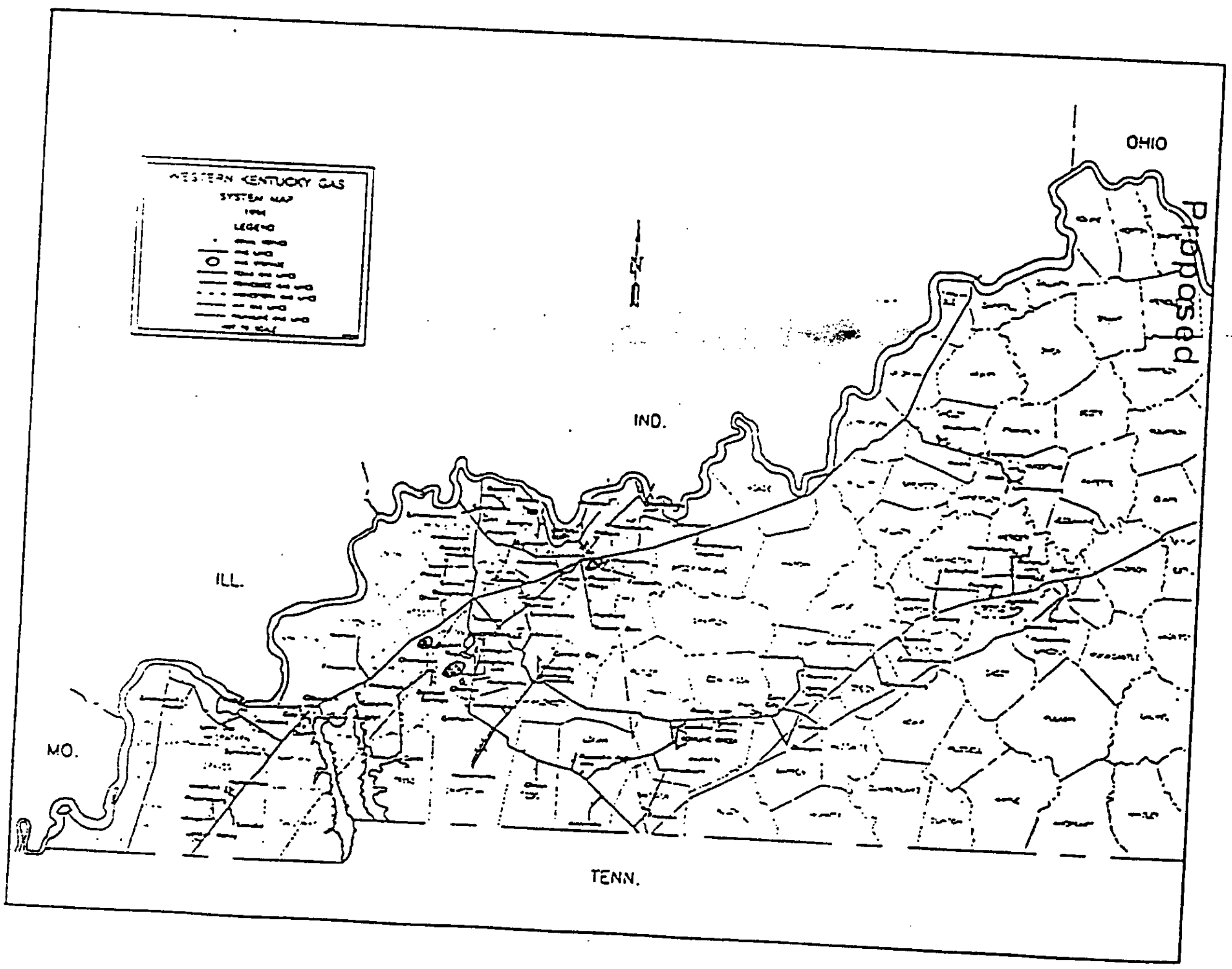
ISSUED BY: William J. Senter

Vice President -- Rates & Regulatory Affairs

Present



Proposed



Present

For Entire Service Area
P.S.C. No. 20
Seventy-sixth SHEET No. 4
Cancelling
Seventy-fifth SHEET No. 4

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary
Case No. 95-010 YY

Firm Service

Base Charge:

Residential	-	$5.10	per meter per month
Non-Residential	-	13.60	per meter per month
Carriage (T-4)	-	150.00	per delivery point per month
Transportation Administration Fee	-	45.00	per customer per meter

	Sales (G-1)	Transport (T-2)	Carriage (T-4)	
First 300 [1] Mcf	@ 4.5170 per Mcf	@ 1.7801 per Mcf	@ 1.0615 per Mcf	(I, R, N)
Next 14,700 [1] Mcf	@ 4.0140 per Mcf	@ 1.2771 per Mcf	@ 0.5585 per Mcf	(I, R, N)
Over 15,000 Mcf	@ 3.8640 per Mcf	@ 1.1271 per Mcf	@ 0.4085 per Mcf	(I, R, N)

High Load Factor Firm Service

HLF demand charge/Mcf	@ 4.2945	@ 4.2945 per Mcf of daily Contract Demand	(R)
First 300 [1] Mcf	@ 3.9603 per Mcf	@ 1.2234 per Mcf	(I, R)
Next 14,700 [1] Mcf	@ 3.4573 per Mcf	@ 0.7204 per Mcf	(I, R)
Over 15,000 Mcf	@ 3.3073 per Mcf	@ 0.5704 per Mcf	(I, R)

Interruptible Service

Base Charge	-	$150.00	per delivery point per month
Transportation Administration Fee	-	45.00	per customer per meter

	Sales (G-2)	Transport (T-2)	Carriage (T-3)	
First 15,000 [1] Mcf	@ 3.4226 per Mcf	@ 0.6857 per Mcf	@ 0.4936 per Mcf	(I, R, N)
Over 15,000 Mcf	@ 3.2726 per Mcf	@ 0.5357 per Mcf	@ 0.3436 per Mcf	(I, R, N)

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

ISSUED: October 28, 1999 Effective: December 1, 1999

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 YY dated November 23, 1999.)

ISSUED BY: William J. Senter Vice President - Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-seventh SHEET No. 4
Cancelling
Seventy-sixth SHEET No. 4

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary
Case No. 99-070

Firm Service

Base Charge:

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

Rate per Mcf[2]	Sales (G-1)	Transport (T-2)	Carriage (T-4)	(T)
First 300 [1] Mcf	@ $4.6455 per Mcf	@ $1.9086 per Mcf	@ $1.1900 per Mcf	(I,I,I)
Next 14,700 [1] Mcf	@ 4.1145 per Mcf	@ 1.3776 per Mcf	@ 0.6590 per Mcf	(I,I,I)
Over 15,000 Mcf	@ 3.8855 per Mcf	@ 1.1486 per Mcf	@ 0.4300 per Mcf	(I,I,I)

High Load Factor Firm Service

HLF demand charge/Mcf @ $4.2945 @ $4.2945 per Mcf of daily Contract Demand

Rate per Mcf[2]			(T)
First 300 [1] Mcf	@ $4.0888 per Mcf	@ $1.3519 per Mcf	(I,I)
Next 14,700 [1] Mcf	@ 3.5578 per Mcf	@ 0.8209 per Mcf	(I,I)
Over 15,000 Mcf	@ 3.3288 per Mcf	@ 0.5919 per Mcf	(I,I)

Interruptible Service

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

Rate per Mcf[2]	Sales (G-2)	Transport (T-2)	Carriage (T-3)	(T)
First 15,000 [1] Mcf	@ $3.4590 per Mcf	@ $0.7221 per Mcf	@ $0.5300 per Mcf	(I,I,I)
Over 15,000 Mcf	@ 3.2881 per Mcf	@ 0.5512 per Mcf	@ 0.3591 per Mcf	(I,I,I)

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

2 DSM, GRI and MLR Riders may also apply, where applicable. (N)

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Seventy-sixth SHEET No. 5
Cancelling
Seventy-fifth SHEET No. 5

WESTERN KENTUCKY GAS COMPANY

Current Gas Cost Adjustments
Case No. 95-010 YY

Applicable

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

GCA = (EGC - BCOG) + CF + RF + PBRRF

Gas Cost Adjustment Components	G - 1	HLF G - 1	G-2	
EGC (Expected Gas Cost Component)	3.6999	3.1432	3.1432	(I, I, I)
BCOG (Base Cost of Gas)	3.4331	3.4331	2.6513	
EGC - BCOG	0.2668	(0.2899)	0.4919	(I, I, I)
CF (Correction Factor)	(0.2239)	(0.2239)	(0.2239)	(N, N, N)
RF (Refund Adjustment)	(0.0452)	(0.0452)	(0.0150)	(N, N, N)
PBRRF (Performance Base Rate Recovery Factor)	0.0247	0.0247	0.0247	(N, N, N)
GCA (Gas Cost Adjustment)	$ 0.0224	$ (0.5343)	$ 0.2777	(I, I, I)

ISSUED: October 28, 1999 Effective: December 1, 1999

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 YY dated November 23, 1999.)

ISSUED BY: William J. Senter Vice President - Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-seventh SHEET No. 5
Cancelling
Seventy-sixth SHEET No. 5

WESTERN KENTUCKY GAS COMPANY

Current Gas Cost Adjustments
Case No. 99-070

Applicable

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

Gas Charge = GCA (D)

GCA = EGC + CF + RF + PBRRF

Gas Cost Adjustment Components	G-1	HLF G-1	G-2	
EGC (Expected Gas Cost Component)	$3.6999	$3.1432	$3.1432	(N)
CF (Correction Factor)	(0.2239)	(0.2239)	(0.2239)	
RF (Refund Adjustment)	(0.0452)	(0.0452)	(0.0150)	
PBRRF (Performance Based Rate Recovery Factor)	0.0247	0.0247	0.0247	
GCA (Gas Cost Adjustment)	$3.4555	$2.8988	$2.9290	(N)

ISSUED: June 23, 1999 **EFFECTIVE:** December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Seventy-sixth SHEET No. 6
Cancelling
Seventy-fifth SHEET No. 6

WESTERN KENTUCKY GAS COMPANY

Current Transportation and Carriage
Case No. 95-010 YY

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

System Lost and Unaccounted gas percentage: 1.9%

					Simple Margin		Non-Commodity		Gross Margin		
Transportation Service (T-2)[1]											
a) Firm Service											
First	300 [2]	Mcf	@		$1.0615	+	$0.7186	=	$1.7801	per Mcf	(R)
Next	14,700 [2]	Mcf	@		0.5585	+	0.7186	=	1.2771	per Mcf	(R)
All over	15,000	Mcf	@		0.4085	+	0.7186	=	1.1271	per Mcf	(R)
b) High Load Factor Firm Service (HLF)											
Demand			@		$0.0000	+	4.2945	=	$4.2945	per Mcf of daily contract demand	(R)
First	300 [2]	Mcf	@		$1.0615	+	$0.1619	=	$1.2234	per Mcf	(R)
Next	14,700 [2]	Mcf	@		0.5585	+	0.1619	=	0.7204	per Mcf	(R)
All over	15,000	Mcf	@		0.4085	+	0.1619	=	0.5704	per Mcf	(R)
c) Interruptible Service											
First	15,000 [2]	Mcf	@		$0.4936	+	$0.1921	=	$0.6857	per Mcf	(R)
All over	15,000	Mcf	@		0.3436	+	0.1921	=	0.5357	per Mcf	(R)
Carriage Service[3]											
Firm Service (T-4)											
First	300 [2]	Mcf	@		$1.0615	+	$0.0000	=	$1.0615	per Mcf	(N)
Next	14,700 [2]	Mcf	@		0.5585	+	0.0000	=	0.5585	per Mcf	(N)
All over	15,000 [2]	Mcf	@		0.4085	+	0.0000	=	0.4085	per Mcf	(N)
Interruptible Service (T-3)											
First	15,000 [2]	Mcf	@		$0.4936	+	$0.0000	=	$0.4936	per Mcf	(N)
All over	15,000	Mcf	@		0.3436	+	0.0000	=	0.3436	per Mcf	(N)

[1] Includes standby sales service under corresponding sales rates.
[2] All gas consumed by the customer (Sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.
[3] Excludes standby sales service.

ISSUED: October 28, 1999 Effective: December 1, 1999

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 YY dated November 23, 1999.)

ISSUED BY: William J. Senter Vice President - Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Seventy-seventh SHEET No. 6
Cancelling
Seventy-sixth SHEET No. 6

WESTERN KENTUCKY GAS COMPANY

Current Transportation and Carriage
Case No. 99-070

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

System Lost and Unaccounted gas percentage: 1.9%

				Distribution Charge		Non Commodity		Transportation Charge	
Transportation Service (T-2)[1]									(T)
a) Firm Service									
First	300 [2]	Mcf	@	$1.1900	+	$0.7186	=	$1.9086 per Mcf	(I)
Next	14,700 [2]	Mcf	@	0.6590	+	0.7186	=	1.3776 per Mcf	(I)
Over	15,000 [2]	Mcf	@	0.4300	+	0.7186	=	1.1486 per Mcf	(I)
b) High Load Factor Firm Service (HLF)									
Demand			@	$0.0000	+	4.2945	=	$4.2945 per Mcf of daily contract demand	
First	300 [2]	Mcf	@	$1.1900	+	$0.1619	=	$1.3519 per Mcf	(I)
Next	14,700 [2]	Mcf	@	0.6590	+	0.1619	=	0.8209 per Mcf	(I)
Over	15,000	Mcf	@	0.4300	+	0.1619	=	0.5919 per Mcf	(I)
c) Interruptible Service									
First	15,000 [2]	Mcf	@	$0.5300	+	$0.1921	=	$0.7221 per Mcf	(I)
All Over	15,000	Mcf	@	0.3591	+	0.1921	=	0.5512 per Mcf	(I)
Carriage Service[3]									
a) Firm Service (T-4)									
First	300 [2]	Mcf	@	$1.1900	+	$0.0000	=	$1.1900 per Mcf	(I)
Next	14,700 [2]	Mcf	@	0.6590	+	0.0000	=	0.6590 per Mcf	(I)
Over	15,000 [2]	Mcf	@	0.4300	+	0.0000	=	0.4300 per Mcf	(I)
b) Interruptible Service (T-3)									
First	15,000 [2]	Mcf	@	$0.5300	+	$0.0000	=	$0.5300 per Mcf	(I)
All Over	15,000	Mcf	@	0.3591	+	0.0000	=	0.3591 per Mcf	(I)

[1] Includes standby sales service under corresponding sales rates. GRI Rider may also apply. (T)
[2] All gas consumed by the customer (Sales and transportation; firm, high load factor, interruptible, and carriage) will be considered for the purpose of determining whether the volume requirement of 15,000 Mcf has been achieved.
[3] Excludes standby sales service.

SSUED: June 23, 1999 EFFECTIVE: December 15, 1999

SSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

P.S.C. No. 20
Second Revised SHEET No. 11
Cancelling
First Revised SHEET No. 11

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

1. Applicable

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. Availability of Service

Available for any use for individually metered service, other than auxiliary or standby service (except for hospitals or other uses of natural gas in facilities requiring emergency power, however, the rated input to such emergency power generators is not to exceed the rated input of all other gas burning equipment otherwise connected multiplied by a factor equal to 0.15) at locations where suitable service is available from the existing distribution system and an adequate supply of gas to render service is assured by the supplier(s) of natural gas to the company.

3. Net Monthly Rate

a) Base Charge:
$ 5.10 per meter for residential service
$13.60 per meter for non-residential service

b) Commodity Charge:

First [1]	300 Mcf	@	$4.4946 per 1,000 cubic feet
Next [1]	14,700 Mcf	@	3.9916 per 1,000 cubic feet
Over	15,000 Mcf	@	3.8416 per 1,000 cubic feet

c) Gas Cost Adjustment (GCA) Rider

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

ISSUED: October 2, 1995 EFFECTIVE: March 1, 1996

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 11
Cancelling
Second Revised SHEET No. 11

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

1. Applicable

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. Availability of Service

Available for any use for individually metered service, other than auxiliary or standby service (except for hospitals or other uses of natural gas in facilities requiring emergency power, however, the rated input to such emergency power generators is not to exceed the rated input of all other gas burning equipment otherwise connected multiplied by a factor equal to 0.15) at locations where suitable service is available from the existing distribution system and an adequate supply of gas to render service is assured by the supplier(s) of natural gas to the Company.

3. Net Monthly Rate

a) Base Charge
$ 7.50 per meter for residential service (I)
$20.00 per meter for non-residential service (I)

b) Distribution Charge (T)

First [1]	300 Mcf	@	$1.1900 per 1,000 cubic feet	(I)
Next [1]	14,700 Mcf	@	0.6590 per 1,000 cubic feet	(I)
Over	15,000 Mcf	@	0.4300 per 1,000 cubic feet	(I)

c) Weather Normalization Adjustment, referenced on Sheet No. 26. (N)

d) Gas Cost Adjustment (GCA) Rider, referenced on Sheet No. 27. (T)

e) Margin Loss Recovery Rider, referenced on Sheet No. 29L. (N)

f) Demand Side Management Cost Recovery Mechanism, referenced on Sheet No. 30a. (N)

g) Gas Research Institute R&D Rider, referenced on Sheet No. 30d. (N)

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

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 12
Cancelling
Original SHEET No. 12

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

4. Net Monthly Bill

The Net Monthly Bill shall be equal to the sum of the Base Charge, Commodity Charge, and adjustments under the Gas Cost Adjustment (GCA) rider.

5. Minimum Monthly Bill

a) The Base Charge plus any High Load Factor (HLF) demand charge. (T)

b) In addition to the minimum monthly charge, customers assigned seasonal volumes under the Company's Curtailment Plan will be billed a minimum seasonal charge equal to 80% of their Adjusted Seasonal Volumes times the last step in the rate.

c) The minimum bill requirements will be adjusted to make allowance for any time that gas was not available, and for any causes due to force majeure, which includes acts of God, strikes, lockouts, civil commotion, riots and fires. Voluntary reductions in a customer's base period volumes for a season will be accepted upon application by the customer no later than 30 days prior to the beginning of the season in which the reduction is desired. The reduction will be eliminated for the following season unless a continuance of the reduction is requested by the customer in writing 30 days before the beginning of the next season.

To the extent that a voluntary reduction for a winter season is continued in the following winter season the reduction will be made permanent for winter seasons.

To the extent that a voluntary reduction for a summer season is continued in the following summer season the reduction will be made permanent for summer seasons.

6. Service Period

Open order. However, the Company may require a special written contract for large use or abnormal service requirements. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting firm service customers in the area.

ISSUED: October 2, 1995

EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 12
Cancelling
First Revised SHEET No. 12

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

4. Net Monthly Bill

The Net Monthly Bill shall be equal to the sum of the Base Charge, Distribution Charge, the Gas Cost Adjustment (GCA) Rider, and other riders applicable by class of service. (T)

5. Minimum Monthly Bill

The Base Charge plus any High Load Factor (HLF) demand charge, if applicable. (T,D)

6. Service Period

Open order. However, the Company may require a special written contract for large use or abnormal service requirements. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting firm service customers in the area.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 13
(First Substitute)
Cancelling
P.S.C. No. 19
First Revised SHEET No. 3
Original SHEET No. 3A

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1 (T)

7. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

8. Rules and Regulations

Service furnished under this schedule is subject to the Company's Rules and Regulations and to all applicable rate and rider schedules.

ISSUED: September 4, 1992 EFFECTIVE: September 13, 1990

(Issued by Authority of an Order of the Public Service Commission in Case No. 90-013 dated September 13, 1990)

ISSUED BY: Mary S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 13
Cancelling
Original SHEET No. 13
(First Substitute)

WESTERN KENTUCKY GAS COMPANY

General Firm Sales Service
Rate G-1

7. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for services rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

8. Rules and Regulations (T)

Service furnished under this schedule is subject to the Company's Rules and Regulations and to applicable rate and rider schedules.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 15
Cancelling
Original Revised SHEET No. 15

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G–2

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

a) Available on an individually metered service basis to commercial and industrial customers for any use as approved by the Company on a strictly interruptible basis, subject to suitable service being available from existing transmission and/or distribution facilities and when an adequate supply of gas is available to the Company under its purchase contracts with its pipeline supplier. (T)

b) The supply of gas provided for herein shall be sold primarily on an interruptible basis, however, in certain cases and under certain conditions the contract may include High Priority service to be billed under "General Sales Service Rate G–1" limited to use and volume which, in the Company's judgment, requires and justifies such combination service.

c) The contract for service under this rate schedule shall include interruptible service or a combination of High Priority service and Interruptible service, however, the Company reserves the right to limit the volume of High Priority service available to any one customer.

3. **Delivery Volumes**

a) The volume of gas to be sold and purchased under this rate schedule and the related contract shall be established on a daily, monthly and seasonal basis and shall be subject to revision in accordance with the Company's approved curtailment plan.

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95–010 dated October 20, 1995)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 15
Cancelling
First Revised SHEET No. 15

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

1. **Applicable**

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. **Availability of Service**

a) Available on an individually metered service basis to commercial and industrial customers for any use as approved by the Company on a strictly interruptible basis, subject to suitable service being available from the existing transmission and/or distribution facilities and when an adequate supply of gas is available to the Company under its purchase contracts with its pipeline supplier.

b) The supply of gas provided for herein shall be sold primarily on an interruptible basis, however, in certain cases and under certain conditions the contract may include High Priority service to be billed under "General Sales Service Rate G-1" limited to use and volume which, in the Company's judgement, requires and justifies such combination service.

c) The contract for service under this rate schedule shall include interruptible service or a combination of High Priority service and Interruptible service, however, the Company reserves the right to limit the volume of High Priority service available to any one customer.

3. Delivery Volumes (T,N)

a) The volume of gas to be sold and purchases under this rate schedule shall be set forth in a written contract, specifying a maximum daily interruptible sales service volume and shall be subject to revision in accordance with the Company's approved curtailment plan.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President - Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 16
Cancelling
Original SHEET No. 16

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G–2

b) High Priority Service
The volume for High Priority service shall be established on a High Priority Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive in any one day, subject to other provisions of this rate schedule and the related contract.

c) Interruptible Service
The volume for Interruptible service shall be established on an Interruptible Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive subject to other provisions of this rate schedule and the related contract.

d) Revision of Delivery Volumes
The Daily Contract Demand for High Priority service and the Daily Contract Demand for Interruptible service shall be subject to revision as necessary so as to coincide with the customer's normal operating conditions and actual load with consideration given to any anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

4. Net Monthly Rate

a) Base Charge: $150.00 per delivery point per month. (I)
Minimum Charge: The Base Charge plus any Transportation Administration Fee and EFM facilities charge. (T)

b) Commodity Charge:

High Priority Service
The volume of gas used each day up to, but not exceeding the effective High Priority Daily Contract Demand shall be totaled for the month and billed at the "General Firm Sales Service Rate G–1".

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95–010 dated October 20, 1995)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 16
Cancelling
First Revised SHEET No. 16

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

b) High Priority Service
The volume for High Priority service shall be established on a High Priority Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive in any one day, subject to other provisions of this rate schedule and the related contract.

c) Interruptible Service
The volume for Interruptible service shall be established on an Interruptible Daily Contract Demand basis which shall be the maximum quantity the Company is obligated to deliver and which the customer may receive subject to other provisions of this rate schedule and the related contract.

d) Revision of Delivery Volumes
The Daily Contract Demand for High Priority service and the Daily Contract Demand for Interruptible service shall be subject to revision as necessary so as to coincide with the customer's normal operating conditions and actual load with consideration given to any anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

4. Net Monthly Rate

a) Base Charge: $220.00 per delivery point per month (I)
Minimum Charge: The Base Charge plus any Transportation Fee and EFM facilities charge

b) Distribution Charge: (T)

High Priority Service
The volume of gas used each day up to, but not exceeding the effective High Priority Daily Contract Demand shall be totaled for the month and billed at the "General Firm Sales Service Rate G-1".

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 17
Cancelling
Original SHEET No. 17

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

Interruptible Service
Gas used per month in excess of the High Priority Service shall be billed as follows:

First [1] 15,000 Mcf @ $ 3.1449 per 1,000 cubic feet (R)
Over 15,000 Mcf @ 2.9949 per 1,000 cubic feet (R)

c) Gas Cost Adjustment (GCA) Rider

d) Minimum Bill
A minimum seasonal bill shall apply and shall be computed as follows:

1) The minimum summer seasonal bill shall apply to the period April 1, through October 31.

2) The minimum winter seasonal bill shall apply to the period November 1, through March 31.

3) The minimum seasonal bill shall be calculated as the product of 80% of the adjusted seasonal volumes times the rate per Mcf in effect on the last day of the season.

4) Any billing for a deficiency under the seasonal minimum bill shall be made within 60 days of the end of the month of the season and shall be due and payable on or before the 20th of the following month.

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

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 17
Cancelling
First Revised SHEET No. 17

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

Interruptible Service

Gas used per month in excess of the High Priority Service shall be billed as follows:

First 15,000 Mcf $0.5300 per 1,000 cubic feet (I)
Over 15,000 Mcf 0.3591 per 1,000 cubic feet (I)

c) Gas Cost Adjustment (GCA) Rider, referenced on Sheet No. 26. (N)

d) Margin Loss Recovery Rider, referenced on Sheet No. 29L. (D)

e) Demand Side Management Cost Recovery Mechanism, referenced on Sheet No. 30a. (N)

f) Gas Research Institute R&D Rider, referenced on Sheet No. 30d. (N)

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

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 18
Cancelling
P.S.C. No. 19
First Revised SHEET No. 7

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2 (T)

5) The minimum bill requirement will be adjusted to make allowance for any time that gas was not available, and for any causes due to force majeure, which includes acts of God, strikes, lockouts, civil commotion, riots and fires. Voluntary reductions in a customer's base period volumes for a season will be accepted upon application by the customer no later than 30 days prior to the beginning of the season in which the reduction is desired. The reduction will be eliminated for the following season unless a continuance of the reduction is requested by the customer in writing 30 days before the beginning of the next season.

To the extent that a voluntary reduction for a winter season is continued in the following winter season the reduction will be made permanent for winter seasons.

To the extent that a voluntary reduction for a summer season is continued in the following summer season the reduction will be made permanent for summer seasons.

5. Standby or Auxiliary Equipment and Fuel

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

6. Penalty for Unauthorized Overruns

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

ISSUED: September 4, 1992 EFFECTIVE: September 13, 1990

(Issued by Authority of an Order of the Public Service Commission in Case No. 90-013 dated September 13, 1990)

ISSUED BY: Mark S Lamb Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 18
Cancelling
Original SHEET No. 18

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2 (D)

5. Standby or Auxiliary Equipment and Fuel (T)

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

(D)

6. Alternative Fuel Responsive Flex Provision (N)

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable rate on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President - Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 19
Cancelling
P.S.C. No. 19
First Revised SHEET No. 8

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G–2 (T)

b) If at the end of any seasonal period a buyer exceeds its Adjusted Seasonal Volumes for that period the Buyer shall pay a penalty as described in Section 33 of the Company's Rules and Regulations.

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

7. Curtailment

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

b) All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission.

ISSUED: September 4, 1992 EFFECTIVE: September 13, 1990

(Issued by Authority of an Order of the Public Service Commission in Case No. 90–013 dated September 13, 1990)

ISSUED BY: Mary S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 19
Cancelling
Original SHEET No. 19

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

7. Curtailment (D) (T)

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God, strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company. (C)

8. Penalty for Unauthorized Overruns (N)

a) In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

b) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

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

ISSUED: June 23, 1999 EFFECTIVE: December15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 20
(First Substitute)
Cancelling
P.S.C. No. 19
First Revised SHEET No. 9

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

(T)

8. Special Provisions

a) A written contract with a minimum term of one year shall be required.

b) The Rules and Regulations and Orders of the Public Service Commission and of the Company and the Company's general terms and conditions applicable to industrial and commercial sales, shall apply to this rate schedule and all contracts thereunder.

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

9. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

ISSUED: September 4, 1992 EFFECTIVE: September 13, 1990

(Issued by Authority of an Order of the Public Service Commission in Case No. 90-013 dated September 13, 1990)

ISSUED BY: Mary S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 20
Cancelling
Original SHEET No. 20
(First Substitute)

WESTERN KENTUCKY GAS COMPANY

Interruptible Sales Service
Rate G-2

9. Special Provisions (T)

a) A written contract with a minimum term of one year shall be required.

b) The Rules and Regulations and Orders of the Public Service Commission and of the Company and the Company's general terms and conditions applicable to industrial and commercial sales, shall apply to this rate schedule and all contracts thereunder.

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

10. Late Payment Charge (T)

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No. 21
Cancelling
First Revised SHEET No. 21

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

1. Applicable

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. Availability of Service

Available to any customer (with an expected demand of at least 36,500 Mcf per year) where usage is individually metered at locations where suitable service is available from the existing distribution system and an adequate supply of gas to render service is assured by the supplier(s) of natural gas to the company. Except as provided in the service agreement, LVS service is not available in conjunction with any other tariffed gas service.

3. Net Monthly Rate

a) Base Charge:

LVS-1 Service	$ 13.60 per Meter
LVS-2 Service	150.00 per Meter
Combined Service	150.00 per Meter

b) Simple Margin for LVS-1 Service

First[1]	300	Mcf	@	$ 1.0615 per Mcf
Next[1]	14,700	Mcf	@	0.5585 per Mcf
Over	15,000	Mcf	@	0.4085 per Mcf

c) Simple Margin for LVS-2 Service

First[1]	15,000	Mcf	@	$ 0.4936 per Mcf
Over	15,000	Mcf	@	0.3436 per Mcf

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

ISSUED: October 2, 1995

EFFECTIVE: March 1, 1996

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 21
Cancelling
Second Revised SHEET No. 21

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

1. Applicable

Entire Service Area of the Company.
(See list of towns – Sheet No. 3)

2. Availability of Service

Available to any customer (with an expected demand of at least 36,500 Mcf per year) where usage is individually metered at locations where suitable service is available from the existing distribution system and an adequate supply of gas to render service is assured by the supplier(s) of natural gas to the Company. Except as provided in the service agreement, LVS service is not available in conjunction with any other tariffed gas service.

3. Net Monthly Rate

a) Base Charge:

LVS-1 Service	$ 20.00 per Meter	(I)
LVS-2 Service	220.00 per Meter	(I)
Combined Service	220.00 per Meter	(I)

b) Distribution Charge for LVS-1 Service (T)

First[1]	300 Mcf	@	$1.1900 per Mcf	(I)
Next[1]	14,700 Mcf	@	0.6590 per Mcf	(I)
Over	15,000 Mcf	@	0.4300 per Mcf	(I)

c) Distribution Charge for LVS-2 Service (T)

First[1]	15,000 Mcf	@	$0.5300 per Mcf	(I)
Over	15,000 Mcf	@	0.3591 per Mcf	(I)

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

ISSUED: June 23, 1999

EFFECTIVE: December15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 22
Cancelling
Original SHEET No. 22

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

d) The Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) The Weighted Average Commodity Gas Cost is based on current purchase costs including all related variable delivery costs for the billing period for which the gas was delivered.

f) The True-up Adjustment shall be customer account specific and shall include all prior period adjustments known at time of billing.

g) Notice of the Weighted Average Commodity Gas Cost and True-up Adjustment will be filed with the Commission prior to billing.

4. Net Monthly Bill

The Net Monthly Bill shall be equal to the sum of the Base Charge, the High Load Factor demand charge, the Simple Margin, the Non-Commodity Component, the Weighted Average Commodity Gas Cost and the True-up Adjustment. (T)

5. Minimum Monthly Bill

a) The Base Charge and High Load Factor demand charge. (T)

b) In addition to the Base Charge, customers assigned seasonal volumes under the Company's Curtailment Plan will be billed a minimum seasonal charge equal to 80% of their Adjusted Seasonal Volumes times the following:

1) Last step of applicable Simple Margin,
2) Non-Commodity Components and
3) Weighted Average Commodity Gas Cost in effect at the time the minimum bill is assessed.

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President - Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 22
Cancelling
First Revised SHEET No. 22

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

d) The Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) The Weighted Average Commodity Gas Cost is based on current purchase costs including all related variable delivery costs for the billing period for which the gas was delivered.

f) The True-Up Adjustment shall be customer account specific and shall include all prior period adjustments known at time of billing.

g) Notice of the Weighted Average Commodity Gas Cost and True-Up Adjustment will be filed with the Commission prior to billing.

h) Margin Loss Recovery Rider, referenced on Sheet No. 29L. (N)

4. Net Monthly Bill (T)

The Net Monthly Bill shall be equal to the sum of the Base Charge, the High Load Factor demand charge, the Distribution Charge, the Non-Commodity Component, the Weighted Average Commodity Gas Cost and the True-Up Adjustment.

5. Minimum Monthly Bill (T,D)

The Base Charge and High Load Factor demand charge, if applicable.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President - Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 23

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority) (N)

c) The minimum bill requirements will be adjusted to make allowance for any time that gas was not available, and for any causes due to force majeure, which includes acts of God, strikes, lockouts, civil commotion, riots and fires. Voluntary reductions in a customer's base period volumes for a season will be accepted upon application by the customer no later than 30 days prior to the beginning of the season in which the reduction is desired. The reduction will be eliminated for the following season unless a continuance of the reduction is requested by the customer in writing 30 days before the beginning of the next season.

To the extent that a voluntary reduction for a winter period is continued in the following winter period the reduction will be made permanent for winter periods.

To the extent that a voluntary reduction for a summer period is continued in the following summer period the reduction will be made permanent for summer periods.

6. Standby or Auxiliary Equipment and Fuel

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

7. Alternative Fuel Responsive Flex Provision (LVS-2 Service Only)

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable rate on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of an Order of the Public Service Commission in Case No. 92-558 dated December 22, 1993.)

ISSUED BY: *Mary S. Lovell* Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 23
Cancelling
Original SHEET No. 23

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

6. Standby or Auxiliary Equipment and Fuel (D)

It shall be the responsibility of the customer to provide and maintain such stand-by, auxiliary equipment and fuel, as the customer may, in its discretion, require to protect its fuel requirements and best interest and to assure continuous operation during any period of interruption of gas deliveries.

7. Alternative Fuel Responsive Flex Provision (LVS-2 Service Only) (T)

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable distribution charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the applicable Distribution Charge to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component and weighted average commodity gas cost of the customer's otherwise applicable rate. (T)

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 24

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority) (N)

Pursuant to this Section, the Company may flex the otherwise applicable rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component and weighted average commodity gas cost of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

8. Service Agreement

The Company will require a written contract for a minimum term of twelve months. Unless waived, the term of any such contract will begin on either November 1st or April 1st with a minimum of sixty (60) day prior notice by the customer. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting service of equal or higher priority customers in the area.

A customer with an unexpired contract for other services may subscribe to LVS service by contract amendment provided the contract, as amended, has a remaining term of at least twelve months.

The volume of gas to be sold and purchased under this rate schedule and the related contract shall be established on a daily, monthly and seasonal basis. The priority of contract volumes shall be subject to revision in accordance with the Company's approved curtailment plan.

The contract volumes (or service mix) shall be subject to revision by the Company as appropriate so as to coincide with the customer's normal operating conditions and actual load with consideration given to any reasonably anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of an Order of the Public Service Commission in Case No. 92-558 dated December 22, 1993.)

ISSUED BY: Mark S Carll Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 24
Cancelling
Original SHEET No. 24

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

8. Curtailment (N)

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God, strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

9. Penalty for Unauthorized Overruns (N)

a) In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

b) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

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

10. Service Agreement

The Company will require a written contract for a minimum term of twelve months. This contract shall include provisions for load limitations and for curtailment or interruptions as necessary, at the discretion of the Company, to prevent the load adversely affecting service of equal or higher priority customers in the area. (D)

A customer with an unexpired contract for other services may subscribe to LVS service by contract amendment provided the contract, as amended, has a remaining term of at least twelve months.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 25

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority) (N)

9. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

10. Exit Fee

When service under this schedule is discontinued, the customer is responsible for (or entitled to) an exit fee (or refund) equal to the lagging true-up adjustments related to the customer's service period.

11. Rules and Regulations

Service furnished under this schedule and applicable contracts are subject to the Company's Rules and Regulations and to all applicable rate and rider schedules.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of an Order of the Public Service Commission in Case No. 92-558 dated December 22, 1993.)

ISSUED BY: Mark S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 25
Cancelling
Original SHEET No. 25

WESTERN KENTUCKY GAS COMPANY

Large Volume Sales
Rates LVS-1 (High Priority), LVS-2 (Low Priority)

The volume of gas to be sold and purchased under this rate schedule and the related contract shall be established on a daily, monthly and seasonal basis. The priority of contract volumes shall be subject to revision in accordance with the Company's approved curtailment plan.

The contract volumes (or service mix) shall be subject to revision by the Company as appropriate so as to coincide with the customer's normal operating conditions and actual load with consideration give to any reasonably anticipated changes in customer's utilization, subject to the Company's contractual obligations with other customers or its suppliers, and subject to system capacity and availability of the gas if an increased volume is involved.

11. Late Payment Charge (T)

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

12. Exit Fee (T)

When service under this schedule is discontinued, the customer is responsible for (or entitled to) an exit fee (or refund) equal to the lagging true-up adjustments related to the customer's service period.

13. Rules and Regulations (T)

Service furnished under this schedule and applicable contracts are subject to the Company's Rules and Regulations and to applicable rate and rider schedules.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original Sheet No. 26

WESTERN KENTUCKY GAS COMPANY

Reserved for Future Use

ISSUED: November 19, 1998

EFFECTIVE: December 20, 1998

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 26
Cancelling
Original SHEET No. 26

WESTERN KENTUCKY GAS COMPANY

Weather Normalization Adjustment Rider

WNA

(N)

1. Applicable

Applicable to Rate G-1 Sales Service, excluding industrial class only.

The distribution charge per Mcf for gas service as set forth in G-1 Sales Service shall be adjusted by an amount hereinunder described as the Weather Normalization Adjustment (WNA). The WNA shall be applicable to Rate G-1 Sales Service, excluding Industrial Sales Service.

For a five year period commencing on November 1, 2000, the WNA shall apply to all residential, commercial and public authority bills based on meters read during the months of November through April. The WNA shall increase or decrease accordingly by month. The WNA will not be billed to reflect meters read during the months of May through October. Customer base loads and heating sensitivity factors will be determined by class and computed annually.

2. Computation of Weather Normalization Adjustment

The WNA shall be computed using the following formula:

$$WNA_i = R_i \frac{(HSF_i \quad (NDD - ADD)\ )}{(BL_i + \quad (HSF_i \times ADD)\ )}$$

Where:

I	=	any rate schedule or billing classification within a rate schedule that contains more than one billing classification
WNA_i	=	Weather Normalization Adjustment Factor for the ith rate schedule or classification expressed as a rate per Mcf
R_i	=	weighted average rate (distribution charge) of temperature sensitive sales for the ith schedule or classification
HSF_i	=	heat sensitive factor for the ith schedule or classification
NDD	=	normal billing cycle heating degree days
ADD	=	actual billing cycle heating degree days
BL_i	=	base load for the ith schedule or classification

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 27
Cancelling
Original SHEET No. 27

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA (C)

1. Applicable

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

2. Gas Cost Adjustment (GCA)

The Company shall file a Monthly Report with the Commission which shall contain an updated Gas Cost Adjustment (GCA) at least thirty (30) days prior to the beginning of each month. The GCA shall become effective for meter readings on and after the first day of the month.

3. Determination of GCA

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

GCA = (EGC – BCOG) + CF + RF

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

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of an Order of the Public Service Commission in Case No. 92-558 dated December 22, 1993.)

ISSUED BY: Mary S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 27
Cancelling
First Revised SHEET No. 27

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

1. Applicable

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

2. Gas Cost Adjustment (GCA)

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

3. Determination of GCA (T)

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

GCA = EGC + CF + RF

Where:

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

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No. 28
Cancelling
First Revised SHEET No. 28

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

EGC is composed of the following:

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

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

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

Less

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

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

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

7) The cost of Company-use volumes.

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

BCOG- is the Base Cost of Gas per 1,000 cubic feet (Mcf):

1) $ 3.4331 for General Sales Service (G-1) (R)
2) $ 2.6513 for Interruptible Sales Service (G-2) (R)

ISSUED: October 2, 1995

EFFECTIVE: November 1, 1995

Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President - Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 28
Cancelling
Second Revised SHEET No. 28

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

EGC is composed of the following:

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

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

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

Less

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

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

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

7) The cost of Company-use volumes.

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

(D)

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President - Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No.29
Cancelling
First Revised SHEET No.29

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

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

The Company shall file an updated Correction Factor (CF) in its March and September monthly GCA filings, to become effective in April and October, respectively. The March filing shall update the CF for the six months ended December period while the September filing shall update the CF for the six months ended June period.

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

[1] At a rate equal to the average of the "3–Month Commercial Paper Rates" for the immediately preceding 12–month period less 1/2 of 1% to cover the costs of refunding as stated in the KPSC Order from Case No. 7157–KK. These monthly rates are reported in both the Federal Reserve Bulletin and the Federal Reserve Statistical Release.

4. High Load Factor (HLF) Option (T)

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

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

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

Issued by Authority of an Order of the Public Service Commission in Case No. 95–010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 29
Cancelling
First Revised SHEET No. 29

WESTERN KENTUCKY GAS COMPANY

Gas Cost Adjustment
Rider GCA

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

The Company shall file an updated Correction Factor (CF) in its April and October GCA filings, to become effective in May and November respectively. The April filing shall update the CF for the six months ended January while the October filing shall update the CF for the six months ended July. [1] (T)

RF - is the sum of any Refund Factors filed in the current and three preceding quarterly filings. The current Refund Factor reflects refunds received from suppliers during the reporting period. The Refund Factor will be determined by dividing the refunds received plus estimated interest[2], by the annual sales used in the quarterly filing less transported volumes. After a refund factor has remained in effect for twelve months, the difference in the amount received and the amount refunded plus the accrued interest[2] will be rolled into the next refund calculation. The refund account will be operated independently of the CF and only added as a component to the GCA in order to obtain a net GCA. In the event of any large or unusual refunds, the Company may apply to the Commission for the right to depart from the refund procedure herein set forth. (T)

[1] The April GCA filing effective May 2000 shall update the CF for the seven months ended January 2000 to account for the change in methodology ordered in Case No. 99-070. (N)

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

4. High Load Factor (HLF) Option

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

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

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995).

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

Proposed

WESTERN KENTUCKY GAS COMPANY

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original SHEET No. 29L

Margin Loss Recovery Rider
MLR (N)

1. Applicable

Applicable to tariff Sales Service Rates G-1, G-2, LVS-1 and LVS-2. This Margin Loss Recovery Rider is intended to authorize the Company to recover 50% of distribution charge losses that result from (1) discounts pursuant to the Alternate Fuel Responsive Flex Provision, (2) special contracts approved by the Public Service Commission of Kentucky, or (3) a customer's bypass of the Company's system.

2. Calculation of the Margin Loss Recovery Factor

The Margin Loss Recovery Factor will be calculated in accordance with the following formula:

$$MLR = \frac{(ML_f + ML_s + ML_b) \times .5}{S}$$

Where:

MLR is the Margin Loss Recovery Factor

ML_f is the sum of discounts pursuant to the Alternate Fuel Responsive Flex Provision, calculated by multiplying the discount below the customer's otherwise applicable distribution charge times the volumes delivered under the flex provision.

ML_s is the sum of discounts pursuant to special contracts implemented subsequent to Case 99-070, calculated by multiplying the discount below the customer's otherwise applicable distribution charge times the customer's volumes in the test year for Case 99-070 or the customer's current annual volumes (whichever is less).

ML_b is the sum of margin losses associated with customer bypass of the Company's system subsequent to Case 99-070, equaling the total margin attributable to the customer during the test year for Case 99-070.

S is the expected sales volumes as used in the Correcting Factor of the Gas Cost Adjustment Rider

Filing with the Public Service Commission of Kentucky

The MLR shall be filed every January and July, to become effective in February and August, respectively. The February filing shall update the MLR for the six months ended November period while the August filing shall update the MLR for the six months ended May period.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

Proposed

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism
DSM (N)

1. Applicable

Applicable to Rate G-1 Sales Service, residential class only.

The Distribution Charge under Residential Rate G-1 Sales Service, shall be increased or decreased for three annual periods beginning January 2000 by the DSM Cost Recovery Component (DSMRC) at a rate per Mcf in accordance with the following formula:

$$DSMRC = DCRC + DBA$$

Where:

DCRC = DSM Cost Recovery-Current. The DCRC shall include all projected costs for the next twelve-month period. These costs shall be limited to expected payments to program implementation contractors over that period, as well as any costs incurred by or on behalf of the DSM collaborative process. These costs would be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DCRC.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

Proposed

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism

DSM

(N)

DBA = DSM Balance Adjustment. The DBA shall be calculated on a calendar year basis and be used to reconcile the difference between the amount of revenues actually billed through the DCRC and previous applications of the DBA, and the revenues which should have been billed.

The DBA for the upcoming twelve-month period shall be calculated as the sum of the balance adjustments for the DCRC and DBA. For the DCRC, the balance adjustment shall be the difference between the amount billed in a twelve-month period from the application of the DCRC unit charge and the actual cost of the DSM Program during the same twelve-month period.

For the DBA, the balance adjustment shall be the difference between the amount billed in a twelve-month period from the application of the DBA unit charge and the balance adjustment amount established for the same twelve-month period.

The balance adjustment amounts calculated will include interest to be calculated at a rate equal to the average of "3-month Commercial Paper Rate" for the immediately preceding twelve-month period. The balance adjustments plus interest shall be divided by the expected Mcf sales for the upcoming twelve-month period to determine the DBA.

The Company will file modifications to the DSMRC on an annual basis at least two months prior to the beginning of the effective upcoming twelve-month period for billing. This annual filing shall include detailed calculations of the DCRC and the DBA, as well as data on the total cost of the DSM Program over the twelve-month period.

Present

Proposed

WESTERN KENTUCKY GAS COMPANY

Demand-Side Management Cost Recovery Mechanism
DSM (N)

<u>DSM Cost Recovery Component (DSMRC):</u>

DSM Cost Recovery – Current:	$0.0155 per Mcf
DSM Balance Adjustment.	$0.0000 per Mcf
DSMRC Residential Rate G-1	$0.0155 per Mcf

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

Proposed

WESTERN KENTUCKY GAS COMPANY

Gas Research Institute R & D Rider

GRI R & D Unit Charge (N)

Applicable:
This rider applies to the distribution charge applicable to all gas transported by the Company other than Rate T-3 and T-4 Carriage Service.

GRI R&D Unit Charge:
The intent of the Gas Research Institute R&D Unit Charge is to maintain the Company's level of contribution per Mcf as of December 31, 1998. The Unit Charge will be billed according to the transition schedule outlined in the pipelines' tariff.

	Rate Per Mcf
GRI R&D Unit Charge	$0.0004

Note 1: The GRI R&D Unit Charge is a weighted average of the rates under the pipelines' transition schedules and applicable annual volumes.

Waiver Provision:
The GRI R&D Unit Charge may be reduced or waived for one or more classifications of service or rate schedules at any time by the Company by filing notice with the Commission. Any such waiver shall not increase the GRI R&D Unit Charge to the remaining classifications of service or rate schedules without Commission approval.

Remittance of Funds:
All funds collected under this rider will be remitted to Gas Research Institute on a monthly basis. The amounts so remitted shall be reported to the Commission annually.

Reports to the Commission:
A statement setting forth the manner in which the funds remitted have been invested in research and development will be filed with the Commission annually.

Termination of this Rider:
Participation in the GRI R&D funding program is voluntary on the part of the Company. This rider may be terminated at any time by the Company by filing a notice of recision with the Commission.

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No. 34
Cancelling
First Revised SHEET No. 34

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2

1. Applicable

Entire service area of the Company to any customer receiving service under the General Sales Service (G-1) and/or Interruptible Sales Service (G-2).

2. Availability of Service

Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require transportation by the Company to the customer's facilities subject to suitable service being available from existing facilities.

3. Net Monthly Rate

In addition to any and all charges assessed by other parties, there will be applied:

a) Transportation Administration Fee – $45.00 per customer per month

b) Simple Margin for High Priority Service

First[1]	300	Mcf	@	$1.0615	per Mcf
Next[1]	14,700	Mcf	@	0.5585	per Mcf
Over	15,000	Mcf	@	0.4085	per Mcf

c) Simple Margin for Low Priority Service

First[1]	15,000	Mcf	@	$0.4936	per Mcf
Over	15,000	Mcf	@	0.3436	per Mcf

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

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

ISSUED: October 2, 1995 EFFECTIVE: March 1, 1996

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised Sheet No. 34
Cancelling
Second Revised Sheet No. 34

WESTERN KENTUCKY GAS COMPANY

General Transportation Service (T)
Rate T-2

1. Applicable

Entire service area of the Company to any customer receiving service under the General Sales Service (G-1) and/or Interruptible Sales Service (G-2).

2. Availability of Service (T)

Available to any customer with an expected consumption of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require transportation by the Company to the customer's facilities subject to suitable service being available from existing facilities.

3. Net Monthly Rate

In addition to any and all charges assessed by other parties, there will be applied:

a) Transportation Administration Fee - $50.00 per customer per month (I)

b) Distribution Charge for High Priority Service (T)

First[1]	300	Mcf	@	$ 1.1900	per	Mcf	(I)
Next[1]	14,700	Mcf	@	0.6590	per	Mcf	(I)
Over	15,000	Mcf	@	0.4300	per	Mcf	(I)

c) Distribution Charge for Low Priority Service

First[1]	15,000	Mcf	@	$ 0.5300	per	Mcf	(I)
Over	15,000	Mcf	@	0.3591	per	Mcf	(R)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

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

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No. 35
Cancelling
First Revised SHEET No. 35

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T–2

4. **Net Monthly Bill**

The Net Monthly Bill, for T–2 Service, shall be equal to the sum of the Transportation Administration Fee and the appropriate Gross Margin (Simple margin plus Non–commodity component) applied to the customer's transported volumes and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 7 "Special Provisions" of this tariff). The customer will also be billed for purchases and the applicable Base Charge and High Load Factor (HLF) demand charge under Rates G–1 and G–2. (T)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities. (T)

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

ssued by Authority of an Order of the Public Service Commission in Case No. 95–010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised Sheet No. 35
Cancelling
Second Revised Sheet No. 35

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2 (T)

4. **Net Monthly Bill**

The Net Monthly Bill, for T-2 Service, shall be equal to the sum of the Transportation Administration Fee and the appropriate Transportation Charge (Distribution Charge plus Non-commodity component) applied to the customer's transported volumes and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 7 "Special Provisions" of this tariff). The customer will also be billed for purchases and the applicable Base Charge and High Load Factor (HLF) demand charge under Rates G-1 and G-2. (T)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The Level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No. 36
Cancelling
First Revised SHEET No. 36

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2

b) It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving transportation under this Transportation Tariff Rate (additional facilities may be required to allow for changing from weekly or monthly meter readings to a daily meter record for the billing period). Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communication support services related to the EFM equipment. Provided, however, EFM equipment is not required for customers whose contractual requirements with the Company are less than 300 MCF/Day. Customers required to install EFM may elect the optional monthly EFM facilities charge (Sheet No.51). (T)

8. Terms and Conditions

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

b) Gas transported under this Transportation Tariff Rate is subject to the provisions of the Company's curtailment order.

c) The Company will not be obligated to deliver a total supply of gas to the customer in excess of the customer's maximum contracted volumes.

d) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas transported under this Transportation Tariff Rate to the facilities of the Company.

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

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

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

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Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 36
Cancelling
Second Revised SHEET No. 36

WESTERN KENTUCKY GAS COMPANY

General Transportation Service (T)
Rate T-2

b) It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving transportation under this Transportation Tariff Rate (additional facilities may be required to allow for changing from weekly or monthly meter readings to daily meter record for the billing period). Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charges (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 300 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

8. Terms and Conditions

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

b) Gas transported under this Transportation Tariff Rate is subject to the provisions of the Company's curtailment order.

c) The Company will not be obligated to deliver a total supply of gas to the customer in excess of the customer's maximum contracted volumes.

d) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas transported under this Transportation Tariff Rate to the facilities of the Company.

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

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

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President - Rates & Regulatory Affairs

Present

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2 (T)

9. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable rate on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of an Order of the Public Service Commission in Case No. 92-558 dated December 22, 1993)

ISSUED BY: Mark S. Carll Vice President – Rates & Regulatory Affairs

Proposed

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2 (T)

9. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Third Revised SHEET No. 38
Cancelling
Second Revised SHEET No. 38

WESTERN KENTUCKY GAS COMPANY

General Transportation Service
Rate T-2

(T)

10. Miscellaneous – GF Provision

The Volumetric criteria in Section 2. "Availability of Service", above is waived for customers who were subscribed to T-2 service on December 22, 1993. As to each such customer, this waiver provision will expire upon the effective date of any new, Commission approved gas transportation service for which that customer qualifies.

ISSUED: October 2, 1995

EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Fourth Revised Sheet No. 38
Cancelling
Third Revised Sheet No. 38

WESTERN KENTUCKY GAS COMPANY

(D)

Reserved for Future Use

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No. 40
Cancelling
First Revised SHEET No. 40

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3

1. **Applicable**

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

2. **Availability of Service**

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require interruptible carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities. (T)

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

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge – $150.00 per delivery point
b) Transportation Administration Fee – 45.00 per customer per month (I)

c) **Simple Margin for Interruptible Service** (N)

First[1]	15,000 Mcf	@ $0.4936 per Mcf	
Over	15,000 Mcf	@ 0.3436 per Mcf	(I)

d) Applicable Non–Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing. (I) (T)

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51). (T)

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

ISSUED: October 2, 1995

EFFECTIVE: November 1, 1995

Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 40
Cancelling
Second Revised SHEET No. 40

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3 (T)

1. **Applicable**

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

2. **Availability of Service**

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require interruptible carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

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

3. **Net Monthly Rate**

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge - $220.00 per delivery point (I)
b) Transportation Administration Fee - 50.00 per customer per month (I)

c) **Distribution Charge for Interruptible Service** (T)

First[1]	15,000 Mcf	@ $0.5300 per Mcf	(I)
Over	15,000 Mcf	@ 0.3591 per Mcf	(R)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

e) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

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

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President - Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No. 41
Cancelling
First Revised SHEET No. 41

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3

4. Net Monthly Bill

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Simple Margin and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 8 "Special Provisions" of this tariff.) (T)

5. Nominated Volume

Definition: "Nominated Volume" or "Nomination" – The level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities. (T)

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: October 2, 1995

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ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 41
Cancelling
Second Revised SHEET No. 41

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3 (T)

4. Net Monthly Bill

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Distribution Charge and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see Subsection 8 "Special Provisions" of this tariff.) (T)

5. Nominated Volume

Definition: "Nominated Volume" or "Nomination" – The level of daily volume inMcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 41A
Cancelling
Original SHEET No. 41A

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3

6. **Imbalances**

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities. (T)

$$\text{Imbalance} = [\,\text{Mcf}_{\text{Customer}} \times (1 - \text{L\&U\%})\,] - \text{Mcf}_{\text{Company}}$$ (T)

Where:

1. "$\text{Mcf}_{\text{Customer}}$" are the total volumes that the customer had delivered to the Company's facilities. (T)
2. "$\text{Mcf}_{\text{Company}}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.
3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. (T)

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-2). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and may be billed at $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff. (T)

If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b). (T)

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 41A
Cancelling
First Revised SHEET No. 41A

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

6. **Imbalances**

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities.

$$\text{Imbalance} = [\,\text{Mcf}_{\text{Customer}}\ X\ (1 - \text{L\&U\%})\,] - \text{Mcf}_{\text{Company}}$$

Where:

1. "$\text{Mcf}_{\text{Customer}}$" are the total volumes that the customer had delivered to the Company's facilities.
2. "$\text{Mcf}_{\text{Company}}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.
3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-2). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff. (N,T)

If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

WESTERN KENTUCKY GAS COMPANY

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 41B
Cancelling
Original SHEET No. 41B

Interruptible Carriage Service
Rate T-3

b) "Cash out" Method

Imbalance volumes		Cash-out Price
First[1] 5% of $Mcf_{Customer}$	@	100% of Index Price[2]
Next[1] 5% of $Mcf_{Customer}$	@	90% of Index Price[2]
Over[1] 10% of $Mcf_{Customer}$	@	80% of Index Price[2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty (s) assessed by the pipeline (s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "$MCF_{Company}$", on a monthly basis at 10¢/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account. (T)

ISSUED: October 2, 1995

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ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 41B
Cancelling
First Revised SHEET No. 41B

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

b) "Cash out" Method

Imbalance volumes		Cash-out Price
First[1] 5% of $Mcf_{Customer}$	@	100% of Index Price[2]
Next[1] 5% of $Mcf_{Customer}$	@	90% of Index Price[2]
Over[1] 10% of $Mcf_{Customer}$	@	80% of Index Price[2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty (s) assessed by the pipeline (s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "$MCF_{Company}$", on a monthly basis at .10/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3

7. **Curtailment**

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

b) All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission.

8. **Special Provisions**

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Interruptible Carriage Service Rate T-3. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communication support services related to the EFM equipment. Provided, however, EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 MCF/day. Customers required to install EFM may elect the optional monthly EFM facilities charge (Sheet No. 51). (T)

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

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel.

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

7. **Curtailment**

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

b) All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission.

8. **Special Provisions**

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Interruptible Carriage Service Rate T-3. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charge (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel. (D)

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Second Revised SHEET No. 43
Cancelling
First Revised SHEET No. 43

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3

9. Terms and Conditions

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

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

c) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas under this Interruptible Carriage Service Rate to the facilities of the Company. (T)

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

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

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Third Revised SHEET No. 43
Cancelling
Second Revised SHEET No. 43

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service
Rate T-3 (T)

9. Terms and Conditions

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

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

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

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

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

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 44
Cancelling
Original SHEET No. 44
(First Substitute)

WESTERN KENTUCKY GAS COMPANY

Carriage Service
Rate T-3 (T)

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

10. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of an Order of the Public Service Commission in Case No. 92-558 dated December 22, 1993)

ISSUED BY: Mary S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 44
Cancelling
First Revised SHEET No. 44

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

g) The customer will be solely responsible to correct, any imbalances it has caused on the applicable pipeline's system.

10. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 45

WESTERN KENTUCKY GAS COMPANY

Carriage Service
Rate T-3 (N)

11. **Alternative Fuel Responsive Flex Provision**

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable rate on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of an Order of the Public Service Commission in Case No. 92-558 dated December 22, 1993)

ISSUED BY: Mark S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 45
Cancelling
Original Sheet No. 45

WESTERN KENTUCKY GAS COMPANY

Interruptible Carriage Service (T)
Rate T-3

11. **Alternative Fuel Responsive Flex Provisions**

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the applicable Distribution Charge on a customer specific basis, if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 46
Cancelling
Original SHEET No. 46

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

1. Applicable

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

2. Availability of Service

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require firm carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

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

3. Net Monthly Rate

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge – $150.00 per delivery point
b) Transportation Administration Fee – 45.00 per customer per month

c) Simple Margin for Firm Service

First[1]	300 Mcf	@	$1.0615	per Mcf
Next[1]	14,700 Mcf	@	0.5585	per Mcf
Over	15,000 Mcf	@	0.4085	per Mcf

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

c) Electronic Flow Measurement ("EFM") facilities charge, if applicable (Sheet No. 51).

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

ISSUED: October 2, 1995 EFFECTIVE: March 1, 1996

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 46
Cancelling
First Revised SHEET No. 46

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

1. Applicable

Entire Service Area of the Company to any customer for that portion of the customer's firm requirements not included under one of the Company's sales tariffs.

2. Availability of Service

a) Available to any customer with an expected demand of at least 9,000 Mcf per year, on an individual service at the same premise, who has purchased its own supply of natural gas and require firm carriage service by the Company to customer's facilities subject to suitable service being available from existing facilities.

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

3. Net Monthly Rate

In addition to any and all charges assessed by other parties, there will be applied:

a) Base Charge - $220.00 per delivery point (I)

b) Transportation Administration Fee - 50.00 per customer per month (I)

c) Distribution Charge for Firm Service

First[1]	300 Mcf	@	$1.1900	per Mcf	(T) (I)
Next[1]	14,700 Mcf	@	0.6590	per Mcf	(I)
Over	15,000 Mcf	@	0.4300	per Mcf	(I)

d) Applicable Non-Commodity Components (Sheet No. 6) as calculated in the Company's Gas Cost Adjustment (GCA) filing.

c) Electronic Flow Measurement ("EFM") facilities charges, if applicable (Sheet No. 51).

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

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 47

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4 (N)

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Simple Margin and Non-Commodity Component, and any applicable Electronic Flow Measurement ("EFM") facilities charges (see subsection 8 "Special Provisions" of this tariff.)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume in Mcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47
Cancelling
Original SHEET No. 47

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

4. **Net Monthly Bill**

The Net Monthly Bill shall be equal to the sum of the Base Charge, the Transportation Administration Fee, and applicable Distribution Charge and Non-Commodity Component, and any applicable (T) Electronic Flow Measurement ("EFM") facilities charges (see subsection 8 "Special Provisions" of this tariff.)

5. **Nominated Volume**

Definition: "Nominated Volume" or "Nomination" – The level of daily volume inMcf as requested by the customer to be transported and delivered by the Company. Such volume nominated by the Customer shall include an allowance for the Company's system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6. The volumes delivered by the Customer to the Company for redelivery to the Customer's facilities will be reduced to cover the related system Lost and Unaccounted gas quantities.

Such nomination request shall be made by the customer to the Company on a periodic basis prior to the nomination deadline of the respective interstate transporter. Such nomination may be adjusted prospectively from time to time during the billing period as may become necessary. However, the Company retains the right to limit the number of nomination adjustments during the billing period.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 47A

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(N)

6. **Imbalances**

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas qunatities.

Imbalance = $[\,Mcf_{Customer} \times (1 - L\&U\%)\,] - Mcf_{Company}$

Where:

1. "$Mcf_{Customer}$" are the total volumes that the customer had delivered to the Company's facilities.
2. "$Mcf_{Company}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.
3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-1). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and may be billed at $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff.

If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

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ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47A
Cancelling
Original SHEET No. 47A

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

6. **Imbalances**

The Company will calculate, on a monthly basis, the customer's Imbalance resulting from the differences that occur between the volume that the customer had delivered into the Company's facilities and the volume the Company delivered to the customer's facilities plus an allowance for system Lost and Unaccounted gas quantities.

Imbalance = $[\,Mcf_{Customer} \times (1 - L\&U\%)\,] - Mcf_{Company}$

Where:

1. "$Mcf_{Customer}$" are the total volumes that the customer had delivered to the Company's facilities.
2. "$Mcf_{Company}$" are the volumes the Company delivered into customer's facilities, however, the Company will adjust the Imbalance, if at the Company's request, the customer did not take deliveries of the volumes the customer had delivered to the Company's facilities.
3. "L&U%" is the system Lost and Unaccounted gas percentage as stated in the Company's current Transportation and Carriage tariff Sheet No. 6.

The Imbalance volumes will be resolved by use of the following procedure:

a) If the Imbalance is negative and Imbalance volumes were approved by the Company, then the customer will be billed for the Imbalance volumes at a rate equal to 110% of the Company's sales rate (G-1). However, if the Imbalance volumes were not approved by the Company, then the Imbalance volumes shall be deemed as an overrun and may be billed at $15.00 per Mcf. The Company has no obligation to provide gas supply to a customer electing service under this tariff.

If the Imbalance is positive, then the Company will purchase the Imbalance volumes in excess of "parked" volumes from the customer at the rates described in the following "Cash out" method in item (b).

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 47B

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(M)

b) "Cash out" Method

Imbalance volumes		Cash-out Price
First[1] 5% of $Mcf_{Customer}$	@	100% of Index Price [2]
Next[1] 5% of $Mcf_{Customer}$	@	90% of Index Price [2]
Over[1] 10% of $Mcf_{Customer}$	@	80% of Index Price [2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty (s) assessed by the pipeline (s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "$MCF_{Company}$", on a monthly basis at 10¢/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

ISSUED: October 2, 1995

EFFECTIVE: November 1, 1995

Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47B
Cancelling
Original SHEET No. 47B

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

b) "Cash out" Method

Imbalance volumes		Cash-out Price
First[1] 5% of $Mcf_{Customer}$	@	100% of Index Price [2]
Next[1] 5% of $Mcf_{Customer}$	@	90% of Index Price [2]
Over[1] 10% of $Mcf_{Customer}$	@	80% of Index Price [2]

[1] Not to exceed the Imbalance volumes

[2] The index price will equal the effective "Cash out" index price in effect for the transporting pipeline or as filed with the Commission by the Company.

c) Customer will be reimbursed for all pipeline transportation commodity charges applying to cash out volumes. However, the reimbursement will not exceed pipeline transportation commodity charges the Company would have incurred to transport the "Cash Out" volumes.

d) In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the pipeline(s) resulting from the customer's failure to match volumes that the customer had delivered to the Company's facilities with volumes the Company delivered into customer's facilities.

e) Customer may, by written agreement with the Company, arrange to "park" positive imbalance volumes, up to 10% of "$MCF_{Company}$", on a monthly basis at .10/MCF per month. The parking service will be provided on a "best efforts" basis by the Company. Parked volumes will be deemed "first through the meter" delivered to the Customer in the month following delivery to the Company on the Customer's account.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 47C

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(M)

7. Curtailment

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God; strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

8. Special Provisions

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Firm Carriage Service Rate T-4. Electronic flow measurement ("EFM") equipment, acceptable to the Company, is required to be installed, maintained, and operated to obtain transportation service. The customer is responsible for providing the electric and communication support services related to the EFM equipment. Provided, however, EFM equipment is not requried for customers whose requirements are less than 100 MCF/day. Customers required to install EFM may elect the optional monthly EFM facilities charge(First Revised Sheet No. 51).

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

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel.

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47C
Cancelling
Original SHEET No. 47C

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(T)

7. Curtailment

All curtailments or interruptions shall be in accordance with and subject to the Company's "Curtailment Order" as contained in Section 33 of its Rules and Regulations as filed with and approved by the Public Service Commission and for any causes due to force majeure (which includes acts of God; strikes, lockouts, civil commotion, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, etc.); and for any other necessary or expedient reason at the discretion of the Company.

8. Special Provisions

It will be the responsibility of the customer to pay all costs for additional facilities and/or equipment which will be required as a result of receiving service under this Firm Carriage Service Rate T-4. Electronic flow measurement ("EFM") equipment is required to be installed, maintained, and operated by the Company to obtain transportation service. The customer is responsible for providing the electric and communications support services related to the EFM equipment. Customers required to install EFM may elect the optional monthly EFM facilities charges (Sheet No. 51). EFM equipment is not required for customers whose contractual requirements with the Company are less than 100 Mcf/day; however, such customers may, at their option, elect to install EFM equipment under the same provisions set forth above. (T)

(D)

No gas delivered under this rate schedule and applicable contract shall be available for resale to anyone other than an end-user for use as a motor vehicle fuel.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
Original SHEET No. 47D

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

9. Terms and Conditions

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

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

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

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

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

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

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

ISSUED: October 2, 1995 EFFECTIVE: November 1, 1995

(Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 47D
Cancelling
Original SHEET No. 47D

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service (T)
Rate T-4

9. Terms and Conditions

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

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

c) It shall be the customer's responsibility to make all necessary arrangements, including obtaining any regulatory approval required, to deliver gas under this Firm Carriage Service Rate to the facilities of the Company. (T)

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

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

f) In the event the customer loses its gas supply, it may be allowed a reasonable time in which to secure replacement volumes (up to the contract daily carriage quantity), subject to provisions of Section 5 of this tariff.

A "reasonable time" will be, except when precluded by operational constraints, matched to the make-up grace period by the respective interstate pipeline transporter.

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

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4

(N)

10. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

11. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the otherwise applicable rate on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request.

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

Proposed

WESTERN KENTUCKY GAS COMPANY

Firm Carriage Service
Rate T-4 (T)

10. Late Payment Charge

A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received shall first be applied to the bill for service rendered. Additional penalty charges shall not be assessed on unpaid penalty charges.

11. Alternative Fuel Responsive Flex Provision

Notwithstanding any other provision of this tariff, the Company may, periodically, flex the applicable Distribution Charge on a customer specific basis if, a customer presents sufficient reliable and persuasive information to satisfactorily prove to the Company that alternative fuel, usable by the customer's facility, is readily available, in both advantageous price and adequate quantity, to completely or materially displace the gas service that would otherwise be facilitated by this tariff. The customer shall submit the appropriate information by affidavit on a form on file with the Commission and provided by the Company. The Company may require additional information to evaluate the merit of the flex request. (T)

Pursuant to this Section, the Company may flex the otherwise applicable transportation rate to allow the delivered cost of gas to approximate the customer's total cost, including handling and storage charges, of available alternative fuel. The minimum flexed rate shall be the non-commodity component of the customer's otherwise applicable rate.

The Company will not flex for volumes which, if delivered, would exceed either (1) the current operable alternative fuel fired capability of the customer's facilities, or (2) the energy equivalent of the quantity of alternative fuel available to the customer, whichever is less. The Company reserves the right to confirm, to its satisfaction, the customer's alternative fuel capability and the reasonableness of the represented price and quantity of available alternative fuel.

Present

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original Sheet No. 49

WESTERN KENTUCKY GAS COMPANY

Reserved for Future Use

ISSUED: November 19, 1998 EFFECTIVE: December 20, 1998

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised Sheet No. 49
Cancelling
Orginal Sheet No. 49

WESTERN KENTUCKY GAS COMPANY

Alternate Receipt Point Service (N)
Rate T-5

1. Applicable
Entire service area of the Company to any customer, subject to limitations noted below, for that portion of the customer's Rate T-2 transportation or carriage service (Rate T-3 or Rate T-4) requirements.

2. Availability of Service
   a) Available, subject to restrictions noted below, to any customer utilizing transportation or carriage services, on an individual service at the same premise, who has purchased its own supply of natural gas and requests delivery to the Company at a receipt point other than the Company's interconnection with the pipeline, or supplier immediately upstream of customer's premises, or the receipt point designated as the primary receipt point in such customer's contract with the Company.
   b) The alternate receipt point through which service is requested must be physically accessible via the Company's existing pipeline system upstream of the delivery point to the customer's facilities.
   c) The Company shall determine the portions of its system to which access may be granted to a specific Alternate Receipt Point.
   d) Access to certain alternate receipt points may be limited or restricted altogether by the Company.
   e) Availability of service is contingent upon the Company's determination that such service is available through existing facilities.
   f) The Company may decline to initiate service to a customer under this tariff, if in the Company's judgment, the performance of such service would be contrary to good operating practice or would have a detrimental impact on other customers serviced by the Company.

3. Net Monthly Rate
In addition to any and all charges assessed by other parties, and in addition to the charges applicable to Customer associated with their Rate T-2 transportation or Rate T-4 carriage service requirements, the following supplemental administrative charge will be applied during months in which volumes are received and transported from the Alternate Receipt Point:

   a) Administrative Charge @ $50.00 per month

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Original Sheet No. 50

WESTERN KENTUCKY GAS COMPANY

Reserved for Future Use

ISSUED: November 19, 1998 EFFECTIVE: December 20, 1998

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised Sheet No. 50
Cancelling
Original Sheet No. 50

WESTERN KENTUCKY GAS COMPANY

Alternate Receipt Point Service (N)
Rate T-5

The administrative fee is waived if, during the month, the Alternate Receipt Point represents the only point of receipt utilized by the customer.

4. Imbalances
   a) Volumes delivered by the Company under the Alternate Receipt Point service may be subjected to imbalance restrictions additional to those specified in the transportation (Rate T-2) or carriage (Rate T-3 or Rate T-4) tariffs.
   b) Banking or Parking allowances for volumes delivered under the Alternate Receipt Point service may be limited or restricted altogether, at the Company's judgment.

5. Terms and Conditions
   a) Volumes under the Alternate Receipt Point service are received for redelivery by the Company on a strictly interruptible basis.
   b) The Company is not responsible for any costs incurred by the customer in its arrangement for gas supply or capacity to the Alternate Receipt Point.
   c) Specific details relating to volume, receipt point(s) and similar matters shall be covered by a separate written contract or amendment with the customer.
   d) Other than provisions referenced herein, or as more specifically set forth in the contract or amendment with the customer, all provisions of the customer's transportation (Rate T-2) or carriage (Rate T-3 or Rate T-4) tariffs shall apply.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. No. 20
First Revised SHEET No. 51
Cancelling
(First Substitute) Original SHEET No. 51

WESTERN KENTUCKY GAS COMPANY

Special Charges

Turn on new service with meter set *	$28.00	(I)
Turn on service (shut–in test required) *	18.00	(I)
Turn on service (meter read only required) *	10.00	(I)
Reconnect delinquent service	no charge	
Reconnect service temporarily off at customers request	25.00	(I)
Termination or field collection charge	5.00	(I)
Special meter reading charge	no charge	
Meter test charge	20.00	
Returned check charge	15.00	(I)
Optional Facilities Charge for Electronic Flow Measurement ("EFM") equipment –		
– Class 1 EFM equipment (less than $7,500, including installation cost)	105.00 per mo.	(N)
– Class 2 EFM equipment (more than $7,500, including installation cost)	210.00 per mo.	(N)

* Waived for qualified low income applicants ("LIHEAP participants")

ISSUED: October 2, 1995

EFFECTIVE: November 1, 1995

Issued by Authority of an Order of the Public Service Commission in Case No. 95-010 dated October 20, 1995.)

ISSUED BY: Lee Allen Everett Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 51
Cancelling
First Revised SHEET No. 51

WESTERN KENTUCKY GAS COMPANY

Special Charges

Service	After Hours	Regular	
Meter Set*	$35.00	$28.00	(N)
Turn-on*	25.00	20.00	(N,I)
Read	14.00	12.00	(N)
Reconnect Delinquent Service	40.00	34.00	(N,I)
Seasonal Charge	73.00	65.00	(N)
Special Meter Reading Charge	N/A	No Charge	
Meter Test Charge	N/A	20.00	
Returned Check Charge	N/A	23.00	(I)
Late Payment Charge (Rate G-1 only)		5%	(N)

Optional Facilities Charge for Electronic Flow Measurement ("EFM") equipment
- Class 1 EFM equipment (less than $7,500, including installation costs) 105.00 per mo.
- Class 2 EFM equipment (more than $7,500, including installation costs) 245.00 per mo. (N)

* Waived for qualified low income applicants ("LIHEAP participants")

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. NO. 20
Original SHEET No. 62
Cancelling
P.S.C. NO. 19
Original SHEET Nos. 1–R thru 19–R
First Revised SHEET Nos. 2–R, 15–R, 18–R

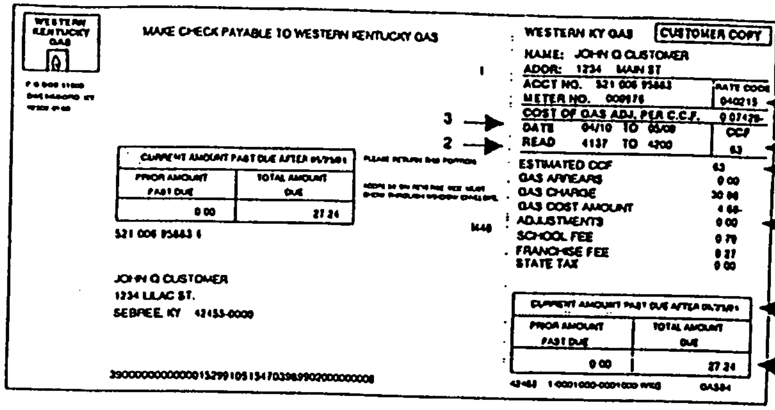
WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

4. **Billings**

a) The following is an example of the monthly bills sent to the Company's residential customers:



1. CLASS OF SERVICE (PLEASE SEE SHEET NO. 7)
2. PRESENT AND LAST PRECEDING METER READING
3. DATE OF PRESENT READING
4. NUMBER OF UNITS CONSUMED
5. METER CONSTANT IF ANY - NOT APPLICABLE TO RESIDENTIAL SERVICE
6. NET AMOUNT FOR SERVICE RENDERED
7. ANY ADJUSTMENTS
8. GROSS AMOUNT OF BILL - NOT APPLICABLE TO RESIDENTIAL SERVICE
9. DATE AFTER WHICH A PENALTY MAY APPLY
10. INDICATES AN ESTIMATED OR CALCULATED BILL

NOTE: LARGE VOLUME COMMERCIAL AND INDUSTRIAL BILLING WILL DISPLAY THE ABOVE INFORMATION, BUT MAY BE PRESENTED IN A DIFFERENT FORMAT.

ISSUED: September 4, 1992 EFFECTIVE: March 4, 1993

ISSUED BY: *Alley S. Lovell* Vice President – Rates & Regulatory Affairs

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Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 62
Cancelling
Original SHEET No. 62

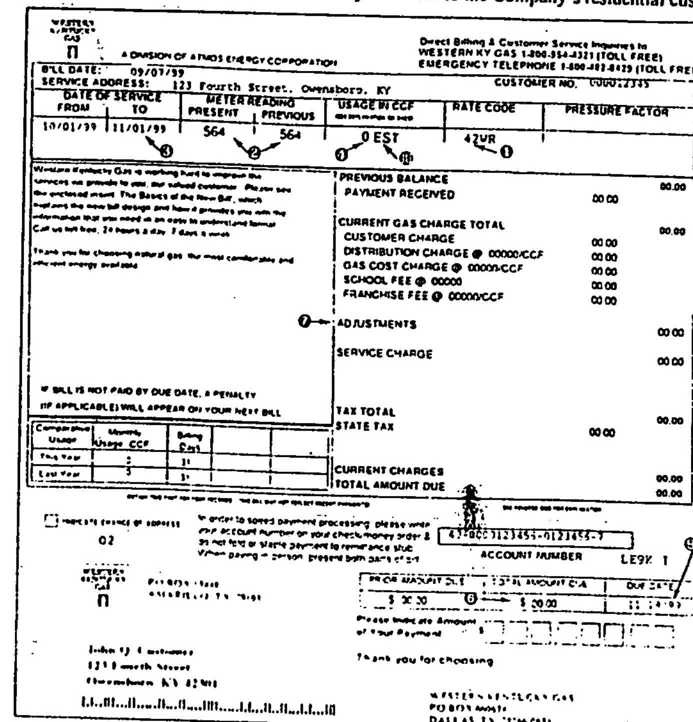
WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

4. **Billings**

a) The following is an example of the monthly bills sent to the Company's residential customers:



1. Class of Service (Please See Sheet No. 7)
2. Present and Last Preceding Meter Reading
3. Date of Present Reading
4. Number of Units Consumed
5. Meter Constant If Any - Not Applicable to Residential Service
6. Net Amount for Service Rendered
7. Any Adjustments
8. Gross Amount of Bill - Not Applicable to Residential Service
9. Date After Which a Penalty May Apply
10. Indicates an Estimated or Calculated Bill

NOTE: Large Volume Commercial and Industrial Billing Will Display the Above Information, but May be Presented in a Different Format.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C,T)

e) The Company will issue to every customer from whom a deposit is collected a receipt of deposit. The receipt will show the name of the customer, location of the service or customer account number, date, and amount of deposit. If the deposit amount changes, the Company will issue a new receipt of deposit to the customer.

f) Except for Winter Hardship Reconnections (as provided by Section 12 of these Rules and Regulations) customer service may be refused or discontinued if payment of requested deposit is not made.

g) Interest will accrue on all deposits at a rate prescribed by law, beginning on the date of deposit. Interest accrued will be refunded to the customer or credited to the customer's bill on an annual basis, except that the Company will not be required to refund or credit interest on deposits if the customer's bill is delinquent on the anniversary of the deposit date. If interest is paid or credited to the customer's bill prior to twelve (12) months from the date of deposit, the payment or credit shall be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill with any remainder refunded to the customer.

When a deposit is required from a customer it will be held for twelve (12) months, or until service is discontinued, unless one of the following has occurred: (a) service has been terminated for non–payment of services or (b) the customer has been late on two (2) or more payments in the last twelve (12) months.

6. Special Charges

The Company may make special nonrecurring charges, approved by the Commission, to recover customer–specific costs incurred to benefit specific customers. Listed below are the special charges included in the company's tariff and a short description of the related service performed or action taken by the Company. See the Special Charges, Sheet No. 51 for the amount of the charge.

a) Turn–on charge. A turn–on charge may be assessed for a new service turn on, seasonal turn on, or temporary service. A turn–on charge shall not be made for initial installation of service where a tap fee is applicable.

ISSUED: September 4, 1992 EFFECTIVE: March 4, 1993

ISSUED BY: Mary S. Lovell Vice President -- Rates & Regulatory Affairs

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Proposed

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

c) The Company will issue to every customer from whom a deposit is collected a receipt of deposit. The receipt will show the name of the customer, location of the service or customer, account number, date, and amount of deposit. If the deposit amount changes, the Company will issue a new receipt of deposit to the customer.

f) Except for Winter Hardship Reconnections (as provided by Section 12 of these Rules and Regulations) customer service may be refused or discontinued if payment of requested deposit is not made.

g) Interest will accrue on all deposits at a rate prescribed by law, beginning on the date of deposit. Interest accrued will be refunded to the customer or credited to the customer's bill on an annual basis, except that the Company will not be required to refund or credit interest on deposits if the customer's bill is delinquent on the anniversary of the deposit date. If interest is paid or credited to the customer's bill prior to twelve (12) months from the date of deposits, the payment or credit shall be on a prorated basis. Upon termination of service, the deposit, any principal amounts, and interest earned and owing will be credited to the final bill with any remainder refunded to the customer.

When a deposit is required from a customer it will be held for twelve (12) months, or until service is discontinued, unless one of the following has occurred: (a) service has been terminated for non-payment of services or (b) the customer has been late on two (2) or more payments in the last twelve (12) months.

6. Special Charges

The Company may make special nonrecurring charges, approved by the Commission, to recover customer-specific costs incurred to benefit specific customers. Listed below are the special charges included in the Company's tariff and a short description of the related service performed or action taken by the Company. See the Special Charges, Sheet No. 51 for the amount of the charge.

a) Meter Set. A meter set charge may be assessed for a new service or re-set, or temporary service. (N)

b) Turn On. A turn on charge may be assessed for connecting service which has been terminated or idle at a given premises for reasons other than nonpayment of bills or violation of the Company or Commission regulations. (T)

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. NO. 20
Original SHEET No. 66
(First Substitute)
Cancelling
P.S.C. NO. 19
Original SHEET Nos. 1-R thru 19-R
First Revised SHEET Nos. 2-R, 15-R, 18-R

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C, T)

b) Reconnect charge. A reconnect charge may be assessed to reconnect a service which has been terminated for nonpayment of bills or violation of the Company rules or Commission regulations. Customers qualifying for service reconnection under Section 12 of these Rules and Regulations shall be exempt from reconnect charges. A reconnect charge may be assessed when the customer's service has been disconnected at his request and at any time subsequently within twelve (12) months is reconnected at the same or any other premises.

c) Termination or field collection charge. A charge may be assessed when a Company representative makes a trip to the premises of a customer for the purpose of terminating service. The charge may be assessed if the Company representative actually terminates service or if, in the course of the trip, the customer pays the delinquent bill to avoid termination. The charge may also be made if the Company representative agrees to delay termination based on the customer's agreement to pay the delinquent bill by a specific date. The Company may make a field collection charge only once in any billing period.

d) Special meter reading charge. This charge may be assessed when a customer requests that a meter be reread and the second reading shows that the original reading was correct. No charge shall be assessed if the original reading was incorrect. This charge may also be assessed when a customer who reads his own meter fails to read the meter for three (3) consecutive months, and it is necessary for a Company representative to make a trip to read the meter.

(No such charge may be assessed until the amount of the charge is approved or otherwise accepted by the Commission.)

e) Meter resetting charge. A charge may be assessed for resetting a meter if the meter has been removed at the customer's request.

(No such charge may be assessed until the amount of the charge is approved or otherwise accepted by the Commission.)

f) Meter test charge. This charge may be assessed if a customer requests the meter be tested pursuant to Section 13 and 807 KAR 5:006 section 18, and the tests show the meter is not more than two (2) percent fast. No charge shall be made if the test shows the meter is more than two (2) percent fast.

ISSUED: September 4, 1992 EFFECTIVE: March 4, 1993

ISSUED BY: Mary S. Lovell Vice President – Rates & Regulatory Affairs

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Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 66
Cancelling
Original SHEET No. 66

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

c) Read. A read charge may be assessed for the establishment of new service where only a meter read is required. (N)

d) Reconnect Delinquent Service. A reconnect delinquent service charge may be assessed to reconnect a service which has been terminated for nonpayment of bills or violation of the Company or Commission regulations. Customers qualifying for service reconnection under Section 12 of these Rules and Regulations shall be exempt from reconnect charges. (T)

e) Seasonal Charge. A seasonal charge may be assessed when the customer's service has been disconnected at his request and at any time subsequently within (12) months is reconnected at the same or any other premises. (N)

f) After Hours Charge. An additional charge shall be applied to any special service activity, including reconnects for delinquent service, initiated at the customer's request outside normal business hours such as at night, on weekends or holidays. The Company shall advise the customer of the applicable after hours charge upon initiation of the service request and offer the customer the alternative to perform the requested activity during normal business hours, including reconnects for delinquent service, as a means to avoid the after hours charge. (N)

g) Special Meter Reading Charge. This charge may be assessed when a customer requests that a meter be reread and the second reading shows that the original reading was correct. No charge shall be assessed if the original reading was incorrect. This charge may also be assessed when a customer who reads his own meter fails to read the meter for three (3) consecutive months, and it is necessary for a Company representative to make a trip to read the meter.

(No such charge may be assessed until the amount of the charge is approved or otherwise accepted by the Commission).

h) Meter Resetting Charge. A charge may be assessed for resetting a meter if the meter has been removed at the customer's request.

i) Meter Test Charge. This charge may be assessed if a customer requests the meter be tested pursuant to Section 13 and 807 KAR 5:006, section 18, and the tests show the meter is not more than two (2) percent fast. No charge shall be made if the test shows the meter is more than two (2) percent fast.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. NO. 20
Original SHEET No. 67
Cancelling
P.S.C. NO. 19
Original SHEET Nos. 1–R thru 19–R
First Revised SHEET Nos. 2–R,15–R,18–R

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C,T)

g) Returned check charge. A returned check charge may be assessed if a check accepted for payment of a Company bill is not honored by the customer's financial institution.

h) Late payment penalty. A penalty may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received will first be applied to the bill for services rendered. Additional penalty charges will not be assessed on unpaid penalty charges.

7. Customer Complaints to the Company

Upon complaint to the Company by a customer at the Company's office, by telephone, or in writing the Company will make a prompt and complete investigation and advise the complainant of its findings. If a written complaint or a complaint made in person at the Company's office is not resolved, the Company will provide written notice to the complainant of his right to file a complaint with the Commission, and will provide him with the address and telephone number of the Commission. If a telephone complaint is not resolved, the Company will provide at least oral notice to the complainant of his right to file a complaint with the Commission and the address and telephone number of the Commission.

8. Bill Adjustments

a) If upon periodic test, request test, or complaint test a meter in service is found to be more than two (2) percent fast, additional tests shall be made to determine the average error of the meter. The test will be made in accordance with Commission regulations applicable to the type of meter involved.

ISSUED: September 4, 1992

EFFECTIVE: March 4, 1993

ISSUED BY: Mary S. Lovell

Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 67
Cancelling
Original SHEET No. 67

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

j) Returned Check Charge. A returned check charge may be assessed if a check accepted for payment of a Company bill is not honored by the customer's financial institution.

k) Late Payment Charge. A late payment charge may be assessed if a customer fails to pay a bill for services by the due date shown on the customer's bill. The penalty may be assessed only once on any bill for rendered services. Any payment received will first be applied to the bill for services rendered. Additional penalty charges will not be assessed on unpaid penalty charges.

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Upon complaint to the Company by a customer at the Company's office, by telephone, or in writing, the Company will make a prompt and complete investigation and advise the complainant of its findings. If a written complaint or a complaint made in person at the Company's office is not resolved, the Company will provide written notice to the complainant of his right to file a complaint with the Commission, and will provide him with the address and telephone number of the Commission. If a telephone complaint is not resolved, the Company will provide at least oral notice to the complainant of his right to file a complaint with the Commission and the address and telephone number of the Commission.

8. Bill Adjustments

a) If upon periodic test, request test, or complaint test, a meter in service is found to be more than two (2) percent fast, additional tests shall be made to determine the average error of the meter. The test will be made in accordance with Commission regulations applicable to the type of meter involved.

ISSUED: June 23, 1999

EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter

Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. NO. 20
Original SHEET No. 78
Cancelling
P.S.C. NO. 19
Original SHEET Nos. 1–R thru 19–R
First Revised SHEET Nos. 2–R,15–R,18–R

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C, T)

e) The customer's service line extending from the outlet of the meter shall be installed and maintained by the customer at his expense.

f) The customer shall notify the Company promptly of any leaks in the transmission line or equipment, also, of any hazards or damages to same.

g) Customers may be required to send in monthly meter readings to the Company on suitable forms provided by the Company.

19. Owners Consent

In case the customer is not the owner of the premises where service is to be provided, it will be the customer's responsibility to obtain from the property owner or owners the necessary consent to install and maintain in or on said premises all such piping and other equipment as are required or necessary for supplying gas service to the customer whether the piping and equipment be the property of the customer or the Company.

The Company will not require a prospective customer to obtain easements or rights–of–way on property not owned by the prospective customer as a condition for providing service. The cost of obtaining easements or rights–of–way will be included in the total per foot cost of an extension, and will be apportioned according to Section 28 in these Rules and Regulations.

20. Customer's Equipment and Installation

a) The customer shall furnish, install and maintain at his expense the necessary customer's service line extending from the Company's service connection at the curb or property line to the building or place of utilization of the gas.

b) The installation of the customer's service line shall be made in accordance with the requirement of the constituted authorities and the Company's specifications covering location, installation, kind and size of pipe, type of pipe coating or wrapping and method of connecting the joints of pipe. The location shall be the point of easiest access to the Company from its facilities and the Company shall be consulted and its approval obtained before the installation is made.

ISSUED: September 4, 1992 EFFECTIVE: March 4, 1993

ISSUED BY: Alan S. Lark Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 78
Cancelling
Original SHEET No. 78

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C,T)

e) The customer's piping extending from the outlet of the meter shall be installed and maintained by the customer at his expense.

f) The customer shall notify the Company promptly of any leaks in the transmission line or equipment, also, of any hazards or damages to same.

g) Customers may be required to send in monthly meter readings to the Company on suitable forms provided by the Company.

19. Owners Consent

In case the customer is not the owner of the premises where service is to be provided, it will be the customer's responsibility to obtain from the property owner or owners the necessary consent to install and maintain in or on said premises all such piping and other equipment as are required or necessary for supplying gas service to the customer whether the piping and equipment be the property of the customer or the Company.

The Company will not require a prospective customer to obtain easements or rights-of-way on property not owned by the prospective customer as a condition for providing service. The cost of obtaining easements or rights-of-way will be included in the total per foot cost of an extension, and will be apportioned according to Section 28 in these Rules and Regulations.

20. Customer's Equipment and Installation

a) The customer shall furnish, install and maintain at his expense the necessary customer's service line extending from the Company's service connection at the curb or property line to the building or place of utilization of the gas.

b) The installation of the customer's service line shall be made in accordance with the requirement of the constituted authorities and the Company's specifications covering locations, installation, kind and size of pipe, type of pipe coating or wrapping, and method of connecting the joints of pipe. The location shall be the point of easiest access to the Company from its facilities and the Company shall be consulted and its approval obtained before the installation is made.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. NO. 20
Original SHEET No. 82
Cancelling
P.S.C. NO. 19
Original SHEET Nos. 1–R thru 19–R
First Revised SHEET Nos. 2–R,15–R,18–R

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(T)

27. Point of Delivery of Gas

The point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of the Company's service connection into the customer's service line or pipe or at the outlet of the meter, whichever is nearest the delivery main of the Company.

28. Distribution Main Extensions

a) The Company will extend without charge an existing distribution main one hundred (100) feet for each single customer provided the following criteria is met:

1) The existing main is of sufficient capacity to properly supply the additional customer(s);

2) Provided that the customer(s) contracts to use gas on a continuous basis for one (1) year or more; and

3) Provided the potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

b) Whenever an extension exceeds one hundred (100) feet per customer, the Company will enter into an agreement with the customer(s) or subscriber(s). The agreement will provide for the extension on a cost per foot basis with the additional amount to be deposited with the Company by the customer(s) or subscriber(s). The agreement will contain provisions for a proportionate and equitable refund in the event other customers are connected to the extension within a ten (10) year period. Refunds shall be made only after the customer(s) has used gas service for a minimum continuous period of one (1) year. The Company reserves the right to determine the length of the extension, to specify the pipe size and location of the extension, and to construct the extension in accordance with its standard practices. Title to all extensions covered by agreements shall be and remain in the Company and in no case shall the amount of any refunds exceed the original deposit. Any further or lateral extension shall be treated as a new and separate extension.

ISSUED: September 4, 1992 EFFECTIVE: March 4, 1993

ISSUED BY: Alley S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
First Revised SHEET No. 82
Cancelling
Original SHEET No. 82

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(T)

27. Point of Delivery of Gas

The point of delivery of gas supplied by the Company shall be at the point where the gas passes from the pipes of the Company's service connection in to the customer's service line or pipe or at the outlet of the meter, whichever is nearest the delivery main of the Company.

28. Distribution Main Extensions

a) The Company will extend an existing distribution main up to one hundred (100) feet for each single customer provided the following criteria is met:

1) The existing main is of sufficient capacity to properly supply the additional customer(s);

2) Provided that the customer(s) contracts to use gas on a continuous basis for one (1) year or more; and,

3) Provided the potential consumption and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible.

b) Whenever an extension exceeds one hundred (100) feet per customer, the Company will enter into an agreement with the customer(s) or subscriber(s). The agreement will provide for the extension on a cost per foot basis with the additional amount to be deposited with the Company by the customer(s) or subscriber(s). The agreement will contain provisions for a proportionate and equitable refund in the event other customers are connected to the extension within a ten (10) year period. Refunds shall be made only after the customer(s) has used gas service for a minimum continuous period of one (1) year. The Company reserves the right to determine the length of the extension, to specify the pipe size and location of the extension, and to construct the extension in accordance with its standard practices. Title to all extensions covered by agreements shall be and remain in the Company and in no case shall the amount of any refunds exceed the original deposit. Any further or lateral extension shall be treated as a new and separate extension.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(T)

33. Curtailment Order

In cases of impairment of gas supply or partial or total interruptions and when it appears that the Company, is or will be, unable to supply the requirements of all of its customers in any system or segment thereof, the Company shall curtail gas service to its customers in the manner set forth below.

a) Definitions:

Residential – Service to customers for residential purposes including housing complexes and apartments.

Commercial – Service to customers engaged primarily in the sale of goods or services including institutions and local and federal agencies for uses other than those involving manufacturing.

Industrial – Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product, including the generation of electric power for sale.

Summer Period – The seven consecutive monthly billing periods of April through October.

Winter Period – The five consecutive monthly billing periods of November through March.

Base Period Volumes – Monthly base period volumes will be specified to each customer's contract with the Company.

Maximum Seasonal Volumes – Maximum Summer Period volumes shall be the assigned Base Period Volumes for the Summer Period; maximum Winter Period Volumes shall be the assigned Base Period volumes for the Winter Period.

Adjusted Seasonal Volumes – A customers maximum seasonal volumes as adjusted from time to time to reflect curtailment in accordance with the Company's priorities of curtailment.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of the Public Service Commission in Case No. 92-558 dated December 22, 1993)

ISSUED BY: *Mark S. Lovell* Vice President – Rates & Regulatory Affairs

Proposed

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

33. Curtailment Order

In cases of impairment of gas supply or distribution system capacity, or partial or total interruptions and when it appears that the Company is, or will be, unable to supply the requirements of all of its customers in any system or segment thereof, the Company shall curtail gas service to its customers in the manner set forth below. (T)

a) Definitions:

Residential – Service to customers for residential purposes including housing complexes and apartments.

Commercial – Service to customers engaged primarily in the sale of goods or services including institutions and local and federal agencies for uses other than those involving manufacturing.

Industrial – Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product, including the generation of electric power for sale.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. NO. 20
First Revised SHEET No. 86
Cancelling
Original SHEET No. 86

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

b) Priorities of Curtailment:

Sales Service

The Company may curtail or discontinue sales service in whole or in part on a daily, monthly or seasonal basis in any purchase zone in accordance with the following priorities, starting with Priority 8 and proceeding in descending numerical order.

High Priority

Priority 1. Residential, and services essential to the public health where no alternate fuel exists (Rate G–1).

Priority 2. Small commercials less than 50 Mcf per day (Rate G–1).

Priority 3. Large commercials over 50 Mcf per day not included under lower priorities (Rates G–1, LVS–1).

Priority 4. Industrials served under Rate G–1 or LVS–1.

Low Priority

Priority 5. Customers served under Rates G–2 or LVS–2 other than boilers included in Priority 6.

Priority 6. Boiler loads shall be curtailed in the following order (Rates G–2 or LVS–2).

a– Boilers over 3,000 Mcf per day.
b– Boilers between 1,500 Mcf and 3,000 Mcf per day.
c– Boilers between 300 Mcf and 1,500 Mcf per day.

Priority 7. Imbalance sales service under Rate T–3.

Priority 8. Flex sales transactions.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of the Public Service Commission in Case No. 92–558 dated December 22, 1993)

ISSUED BY: Neil S Lnell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 86
Cancelling
First Revised SHEET No. 86

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations

(C)

b) Priorities of Curtailment:

Sales Service

The Company may curtail or discontinue sales service in whole or in part on a daily, monthly or seasonal basis in any purchase zone in accordance with the following priorities, starting with Priority 8 and proceeding in descending numerical order.

High Priority

Priority 1. Residential and services essential to the public health where no alternate fuel exists (Rate G-1)

Priority 2. Small commercials less than 50 Mcf per day (Rate G-1).

Priority 3. Large commercials over 50 Mcf per day not included under lower priorities (Rates G-1, LVS-1)

Priority 4. Industrials served under Rate G-1 or LVS-1.

Low Priority

Priority 5. Customers served under Rates G-2 or LVS-2 other than boilers included in Priority 6.

Priority 6. Boiler loads shall be curtailed in the following order (Rates G-2 or LVS-2).

A - Boilers over 3,000 Mcf per day.
B - Boilers between 1,500 Mcf and 3,000 Mcf per day.
C - Boilers between 300 Mcf and 1,500 Mcf per day.

Priority 7. Imbalance sales service under Rate T-3 and Rate T-4.

Priority 8. Flex sales transactions.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

Present

For Entire Service Area
P.S.C. NO. 20
First Revised SHEET No. 87
Cancelling
Original SHEET No. 87

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations (T)

c) Penalties:

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

If, at the end of any seasonal period, a Buyer exceeds its Adjusted Seasonal Volumes for that period, the Buyer shall pay a penalty of $15 per Mcf for all volumes taken in excess of 102% of its adjusted seasonal volume. The penalty is to be in addition to the regular applicable rate, but no such penalty shall be payable for any season in which the excess volume is less than 100 Mcf. The Company, at its sole discretion, may reduce the Buyer's Adjusted Seasonal Volume in the succeeding seasonal period by an amount equal to the excess volume taken.

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

d) Discontinuance of Service

The Company shall have the right, after reasonable notice to discontinue the gas supply of any customer that fails to comply with a valid curtailment order.

ISSUED: March 29, 1993 EFFECTIVE: December 22, 1993

(Issued by Authority of the Public Service Commission in Case No. 92-558 date December 22, 1993)

ISSUED BY: Mark S. Lovell Vice President – Rates & Regulatory Affairs

Proposed

FOR ENTIRE SERVICE AREA
P.S.C. NO. 20
Second Revised SHEET No. 87
Cancelling
First Revised SHEET No. 87

WESTERN KENTUCKY GAS COMPANY

Rules and Regulations (T)

c) Penalty for Unauthorized Overruns

In the event a customer fails in part or in whole to comply with a Company Curtailment Order either as to time or volume of gas used or uses a greater quantity of gas than its allowed volume under terms of the Curtailment Order, the Company may, at its sole discretion, apply a penalty rate of up to $15.00 per Mcf.

In addition to other tariff penalty provisions, the customer shall be responsible for any penalty(s) assessed by the interstate pipeline(s) or suppliers resulting from the customer's failure to comply with terms of a Company Curtailment Order.

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

d) Discontinuance of Service

The Company shall have the right, after reasonable notice to discontinue the gas supply of any customer that fails to comply with a valid curtailment order.

ISSUED: June 23, 1999 EFFECTIVE: December 15, 1999

ISSUED BY: William J. Senter Vice President – Rates & Regulatory Affairs

RECEIVED

NOV 2 2 1999

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
THE APPLICATION OF WESTERN	)	Case No. 99-070
KENTUCKY GAS COMPANY	)	
FOR AN ADJUSTMENT OF RATES	)	

ATTORNEY GENERAL'S RESPONSE
TO WESTERN'S DATA REQUEST
TO THE ATTORNEY GENERAL

Comes now the Attorney General, through his Office of Rate Intervention, and submits his Response to the data request of the Western Kentucky Gas Company.

Respectfully submitted,

A.B. CHANDLER III
ATTORNEY GENERAL

David Edward Spenard

David Edward Spenard
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601-8204
(502) 696.5457

CERTIFICATE OF SERVICE AND FILING

Counsel certifies that an original and fifteen (15) photocopies of the foregoing Attorney General's Response to Western's Data Request to the Attorney General were served and filed by hand delivery to the Hon. Helen C. Helton, Executive Director, Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to William J. Senter, Western Kentucky Gas, 2401 New Hartford Road, Owensboro, KY 42303 1312, Mark R. Hutchinson, Sheffer, Hutchinson & Kinney, 115 East Second Street, Owensboro, KY 42303, John N. Hughes, 124 West Todd Street, Frankfort, KY 40601, Douglas Walther, Atmos Energy Corporation, P.0. Box 650205, Dallas, TX 75265, Keith Tiggelaar, WBI Southern, Inc., P.O. Box 5601, Bixmark, ND 58506 5601, and Robert M. Watt, Jr., J. Mel Camenisch, Jr., 201 E. Main Street, Suite 1000, Lexington, KY 40507-1380, all on this 22nd day of November 1999.

David Edward Spenard

Assistant Attorney General

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Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
Request for Information by
Western Kentucky Gas Company

1. Please provide the syllabi from Dr. Weaver's last two years of teaching at James Madison University.

Answer: Attached

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
FALL 1996

1. Finance 488: Advanced Financial Policy

2. Prerequisite: Finance 365.

3. Texts:

Cases to be purchased from the instructor.

Reference text: Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, Seventh Edition. (Dryden Press, 1994).

Finance 488 Notes: These will be available the third week of classes.

4. Topics to be covered:

1.	Financial Analysis	7.	Lease vs. Buy
2.	Derivatives and SWAPS	8.	International Finance
3.	Capital Structure	9.	Investment Analysis
4.	Cost of Equity	10.	Valuation of a Business
5.	Cost of Capital	11.	Small Business Finance
6.	Capital Budgeting	12.	Resume preparation and the job search.

5. Purpose of Project or Case:

A. Demonstrate a knowledge of the process required to solve the type of problem presented in the project or case.
B. Develop skills using financial-analytical tools.
C. Demonstrate a mastery in the use of the tools by:
   1. recognizing the information and data required; and
   2. making reasonable assumptions when data is not available.
D. Demonstrate the ability to make "informed judgements" from the information obtained in the analysis.

6. Daily Participation:

Class participation counts 20% of the course grade. This portion of your grade will consist of your one-page case write-ups and your participation in class discussion. You get credit for discussion of projects, cases, or other materials; contributing to the presentation by asking insightful questions; or by answering questions asked by another student.

7. One-page Written Reports:

The assigned projects and cases must be written and handed-in. A general outline for the one-page write-ups is shown on the next page.

I. A statement indicating the problem that needs to be addressed.
II. The recommended quantitative analytical method used to resolve the problem.
III. A brief paragraph describing the analytical method.
IV. A brief listing of the data requirements of the analytical method (no more than the five most important items.)

V. A listing of the three most important qualitative facts in the case.

8. Team Presentations:

Case presentations will be assigned to teams. Each team is responsible for two cases -- one as a consulting team and the other as a management team.

9. Role of the Consulting Team and the Management Team:

The consulting team is responsible for presenting and using a methodology for solving the problems that are addressed in the assigned case. The objective is to assure that the class members are knowledgeable about the application and use of the methodology.

The role of the management team is to ask questions and to make suggestions during the presentation. Their role is to assure that the consulting team's presentation is correct and to add reinforcement to the use and application of the methodology conveyed by the case.

10. Class Appraisal of Presentations:

The consulting and management presentations will be graded using both peer and instructor appraisal. The peer appraisal forms will be supplied at a later date. The instructors grade will be based on his questioning the class members in the audience to determine their level of understanding of the material that is being presented.

11. Attendance:

Class attendance is expected. Your final average will be lowered one letter grade for each absence in excess of two for each unexcused absence.

12. Appraisal:

One-page write-ups & Class Participation	20%
Presentations & Reports	40%
Assessment Test	20%
Final Exam	20%

13. Grading Scale:

A - 91-100%
B - 81-90%
C - 71-80%
D - 61-70%
F - 60% or below

14. Office Hours:

Tuesday:	9:00-11:30 and 3:00-4:30 pm
Wednesday:	9:30-10:30
Thursday:	9:00-11:00

Occasionally I will not be available during these hours because of meetings. It is best to make an appointment or use e-mail for questions or discussion.

15. E-mail address: WEAVERCG
Office: Showker 215
Telephone: (540) 568-3080

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
Fall 1996

1. Finance 645: Financial Theory and Analysis

2. Prerequisite: Finance 545 or equivalent. Accounting 673 is recommended.

3. Texts:

   Darden Graduate School of Business Administration cases purchased through the instructor. (These will be available around mid-semester.)

   Eugene F. Brigham and Louis C. Gapenski, <u>Financial Management, Theory and Practice, Seventh Edition</u>. (Dryden Press, 1994).

   Finance 645 Lecture Notes. These can be purchased from the COB Print Shop.

4. Topics Covered:

   a. Financial Analysis
   b. Cash Flow Analysis
   c. Industry Characteristics
   d. Cash Budgeting
   e. Accounts Rec. Management
   f. Inventory Management
   g. Accounts Payable Management
   h. Short Financing
   i. Cost of Equity
   j. Weighted Avg. Cost of Capital
   k. Capital Budgeting
   l. Risk & Capital Budgeting

5. Course Delivery: Projects and Cases

6. Written Reports:

   The assigned projects and cases must be written and handed-in. A <u>general</u> outline for the write-ups is shown below. This outline normally must be modified so that it is applicable to a particular case or project.

   I. Problem or objective statement.

   II. Economic environment if applicable.

   III. Method of analysis and description of the financial tools being used.

   IV. The analysis. Place detailed exhibits in the back of the report as appendixes.

   V. Conclusions.

7. **Purpose of Project or Case:**

   A. Demonstrate a knowledge of the process required to solve the type of problem presented in the project or case.

   B. Develop skills using financial-analytical tools.

   C. Demonstrate a mastery in the use of the tools by:
      1. recognizing the information and data required; and
      2. making reasonable assumptions when data is not available.

   D. Demonstrate the ability to make "informed judgements" from the information obtained in the analysis.

8. **Class Participation:**

   Class participation counts 10% of the course grade. You get credit for discussion of projects, cases, or other materials; contributing to the presentation by asking insightful questions; or by answering questions asked by another student. It is your responsibility to assure that the instructor knows your name.

9. **Appraisal:**

Class Participation	10%
Written Reports	35%
Mid-term Exam	25%
Final Exam	30%

10. **Grading Scale:**

   A - 91-100%
   B - 81-90%
   C - 71-80%
   F - 70 or below

11. **Office Hours:**

Monday:	9:30-11:30
Tuesday:	9:30-11:30 & 14:00-16:00
Wednesday:	9:30-11:30

   Occasionally I will not be available during these hours.

12. E-mail address: WEAVERCK
    Telephone: (540) 568-3080

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
SPRING 1997

1. Finance 488: Advanced Financial Policy

2. Prerequisite: Finance 365.

3. Texts:

Cases to be purchased from the COB Copy Center (these will be available after 1/14/97).

Reference text: Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, Seventh Edition. (Dryden Press, 1994).

4. Topics to be covered:

1.	Financial Analysis	7.	International Finance
2.	Capital Budgeting	8.	Investment Analysis
3.	Capital Structure	9.	Lease vs. Buy
4.	Cost of Capital	10.	Small Business Finance
5.	Cost of Equity	11.	Resume preparation and the job search
6.	Derivatives and SWAPS	12.	Valuation of a Business

5. Purpose of Project or Case:

A. Demonstrate a knowledge of the process required to solve the type of problem presented in the project or case.
B. Develop skills using financial-analytical tools.
C. Demonstrate a mastery in the use of the tools by:
   1. recognizing the information and data required; and
   2. making reasonable assumptions when data is not available.
D. Demonstrate the ability to make "informed judgements" from the information obtained in the analysis.

6. Team Presentations:

Case presentations will be assigned to teams. Each team is responsible for two cases -- one as a consulting team and the other as a management team.

7. Role of the Consulting Team and the Management Team:

The consulting team is responsible for presenting and using a methodology for solving the problems that are addressed in the assigned case. The objective is to assure that the class members are knowledgeable about the application and use of the methodology.

The role of the management team is to ask questions and to make suggestions during the presentation. Their role is to assure that the consulting team's presentation is correct and to add reinforcement to the use and application of the methodology conveyed by the case.

8. Class Participation:

Class participation counts 20% of the course grade. This portion of your grade will consist of one-page case outlines and participation in class discussion. Credit is given for contributing to the presentation by asking insightful questions or by answering questions.

9. One-page Outlines:

An outline, which is to be turned-in on the day of the case presentation by each student in the class other than the management and consulting team members, for the one-page reports is shown below. No outlines will be accepted late.

I. Problem Statement - a statement or question that indicates the problem that needs to be addressed in a decision statement.

II. Analytical Method - the recommended analytical tool used to provide information for making a decision.

III. Analytical Method Description - a brief paragraph describing the analytical method.

IV. Data Requirements - a listing of the data required to implement the analytical method (no more than the five most important items.)

V. Qualitative Facts - a listing of the three most important qualitative facts that must be considered in the decision recommendation that resolves the problem.

10. Class Appraisal of Presentations:

The presentations and class participation grades will be assigned by the instructor. The presentations are expected to be professional, informative, accurate, and demonstrate expertise in the topic being examined. The class participation grades will be based on questions asked by students and by the instructors questioning the class members in the audience to determine their level of understanding of the material that is being presented.

11. Attendance: Class attendance is expected. Your final average will be lowered one letter grade for each absence in excess of two for each unexcused absence.

12. Appraisal:

One-page write-ups & Class Participation	20%
Presentations & Reports	40%
Assessment Test	20%
Final Exam	20%

13. Grading Scale:

A - 91-100%
B - 81-90%
C - 71-80%
D - 61-70%
F - 60% or below

14. Office Hours:

Monday:	9:00-11:30
Tuesday:	1:30- 3:00
Wednesday:	9:30-10:30

Occasionally I will not be available during these hours because of meetings. It is best to make an appointment or use e-mail for questions or discussion.

15. E-mail address: WEAVERCG
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Telephone: (540) 568-3080

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
Spring 1997

1. **Finance 655: Advanced Topics in Financial Management**

Financial theory and analytical techniques are applied to business problems in a case environment. The objective is to determine optimum decisions based upon an integration of financial, accounting, economic, and behavioral factors.

2. **Prerequisite: Finance 645.**

3. **Texts:**

Cases that are purchased through the instructor.
Packet purchased from COB Print Shop.
Text: Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, 8th Edition. (The Dryden Press, 1997).

4. **Topics to be Covered:**

SWAPS
Valuation
Capital Structure
Dividend Policy
Venture Capital
Bankruptcy and Reorganization
Mergers and Acquisitions
The creation and destruction of value

5. **General Analytical Procedure:** (not all steps can be done for each case)

A. Determine the problem or topic to be analyzed.
B. Examine Economic Data for period of case.
C. Do a financial and cash flow analysis to determine the financial condition of the company being analyzed.
D. Construct a pro-forma statement that will reflect and provide information about the scenario being examined.
E. Use pro-forma statement to do sensitivity analysis showing different alternative decisions.
F. Do a financial and cash flow analysis on the pro-forma results to obtain information about each alternative.
G. Attempt to estimate the qualitative results of the alternative decisions on the firm. (Value; financial flexibility, risk, control, employees, customers, suppliers, etc.)
H. Make the decision.

6. **Team presentations:**

Each team is responsible for two cases and one article. One of the cases will be presented as a consulting team and the other will be prepared to question the presentation as a management team. The article will be prepared as a presentation.

7. **Role of the Consulting Team and the Management Team:**

The consulting team is responsible for presenting the case. The role of the management team is to ask questions and to make suggestions during the presentation. The intended result of this dialogue is to enhance the class's understanding of the material that is presented. The teams should prepare the case independently of one another.

The Management Team's questions and comments should be directed toward: clarifying the analytical method being used; identifying and questioning the assumptions that are being made in the analysis; helping focus on the implications of the results on owners, management, employees, suppliers, customers, the community or other stakeholders; etc.

8. Case Presentation Outline:

The assigned cases must be outlined and handed-in by their respective consulting and management teams. A suggested guide for the outline that can generally be used is given below.

Suggested Outline for Cases

I. Problem or objective statement:
   A. Phrased as a question, or;
   B. Major financial task that needs to be addressed.

II. Economic environment at time of case that relates to the problem or objective should be considered. You should be aware of how the economic conditions will effect the topic or problem undergoing examination. For example, if it appears the economy is entering a recession, that should be considered in the revenue forecast. Only consider those economic data that are pertinent to the analysis.

III. Method of Analysis:
   A. Description of new analytical financial tools that are being used.
   B. Explanation how the quantitative tools will be applied. The presentation should provide sufficient explanation so that the class is trained in the use of the tools.
   C. Description of the qualitative considerations.

IV. Analysis:
   A. Describe the results of the implementation of the analytical tools.
   B. Address both the quantitative and qualitative issues.

V. Conclusion: Be certain to address the problem statement or objective set forth in item I above and support your conclusion with the results of your analysis.

9. Class participant responsibility:

Each class participant must turn-in a one-page report for each case which contains the following information:

I. A statement indicating the problem that needs to be addressed.
II. The recommended quantitative analytical method used to resolve the problem.
III. A brief paragraph describing the analytical method.
IV. A brief listing of the data requirements of the analytical method (no more than 5 of the most important items).
V. A listing of three most important qualitative facts in the case.

9. Appraisal:

Cases and Article Presentations @15% each	45%
Written Case Outline @ 10% each	20%
Class Participant Reports	10%
Class Discussion Participation	5%
Take-home Final	20%

10. Grading Scale:

A - 91-100%
B - 81-90%
C - 71-80%
F - 70 or below

11. Office Hours: Monday & Thursday: 9:30-11:30

12. Telephone Number: JMU - (540) 568-3080
Home - (540) 433-9288

13. E-Mail Address: WEAVERCK

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
FALL 1997

1. Finance 488: Advanced Financial Policy

2. Prerequisite: Finance 365.

3. Texts:

Cases to be purchased from the COB Copy Center (these will be available after 5/8/97).

Reference text: Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, Eighth Edition. (Dryden Press, 1997). This text is not required. You may use the same text used in your Finance 365 course.

4. Topics to be covered:

   1. Financial Analysis
   2. Capital Budgeting
   3. Capital Structure
   4. Cost of Capital
   5. Cost of Equity
   6. Derivatives and SWAPS
   7. International Finance
   8. Investment Analysis
   9. Lease vs. Buy
   10. Small Business Finance
   11. Valuation of a Business

5. Purpose of Project or Case:

   A. Demonstrate a knowledge of the process required to solve the type of problem presented in the project or case.

   B. Develop skills using financial-analytical tools.

   C. Demonstrate a mastery in the use of the tools by:
      1. recognizing the information and data required; and
      2. making reasonable assumptions when data is not available.

   D. Demonstrate the ability to make "informed judgements" from the information obtained in the analysis.

6. Team Presentations:

Case presentations will be assigned to teams. Each team is responsible for presenting two cases. The instructor will call on students in the class to elaborate point made in the presentation.

7. Class Participation:

Class participation counts 20% of the course grade. This portion of your grade will consist of one-page case outlines and participation in class discussion.

8. One-page Outlines:

An outline for the one-page reports, which is to be turned-in on the day indicated in the syllabus, is shown below. A team performing a presentation will hand in a hard copy of the presentation outline and visual aids. NO Papers will be accepted late.

I.	Problem Statement -	a statement or question that indicates the problem that needs to be addressed in a decision statement.
II.	Analytical Method -	the recommended analytical tool used to provide information for making a decision and a brief description of that tool.
III.	Data Requirements -	a listing of the data required to implement the analytical method (no more than the five most important items.)
IV.	Qualitative Facts -	a listing of the three most important qualitative facts that must be considered in the decision recommendation that resolves the problem.

9. Class Appraisal of Presentations:

The presentations and class participation grades will be assigned by the instructor. The presentations are expected to be professional, informative, accurate, and demonstrate expertise in the topic being examined. The class participation grades will be based on questions asked by students and by the instructors questioning the class members in the audience to determine their level of understanding of the material that is being presented.

10.	Attendance:	Class attendance is expected. Your final average will be lowered one letter grade for each absence in excess of TWO for each unexcused absence. The possibility of having an absence excused is slim to none.	
11.	Appraisal:	One-page write-ups & Class Participation	20%
		Presentations & Reports	30%
		Mid-term Exam	20%
		Final Exam	30%
12.	Grading Scale:	A - 91-100%	D - 61-70%
		B - 81-90%	F - 60% or below
		C - 71-80%	
13.	Office Hours:	Monday:	1:00-2:00
		Tuesday:	9:30- 1:30
14.	E-mail address:	WEAVERCG	
	Office:	Showker 344	
	Telephone:	(540) 568-3080	

Finance 365 - Intermediate Finance
FALL SEMESTER 1997

PREREQUISITE: Finance 345

INSTRUCTOR: Dr. Carl Weaver, Showker 444 — E-mail address: **FAC_WEAVER**, Phone: 568-3080

OFFICE HOURS:
Tu-Th 10:00-11:30
Tu-Th 15:00-16:00
Other hours by **appointment.**

TEXTS:

1. Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, 7th Edition, (The Dryden Press) 1994.
2. Dukes Duplicates Lecture Notes
3. The recommended calculator is the Hewlett-Packard 12-C or 17-B.

SEAT CHART: A seat chart will be prepared on Tuesday, September 6. For the remainder of the semester, always sit in the same seat as the one you selected on that date.

ATTENDANCE: Attendance is required for the satisfactory completion of this course. Any absence in excess of two classes will result in your grade being lowered by one letter grade for each additional absence. As a general rule, there will be no exceptions to this policy.

TIME COMMITMENT: There will numerous projects that you must complete. This is a "hands on" course. Each project will require approximately six to eight hours for its completion. This time estimate assumes that you don't waste a lot of time getting started. Some projects will take more than eight hours; others, less. If you are not able to devote this time to this course - drop it!

TEAMS: You will be on a different team for each project. Sometimes you may be on a team of one - yourself. The team configuration is determined by your student number and the letter which designates the project team configuration to be used. On a project's due date, each student must turn-in a confidential performance appraisal. No projects will be accepted late. Failure to turn in a project will result in that team's participants receiving an "F" for the course.

MATERIAL SOURCES: On each report, all direct or close quotations and data sources should be footnoted.

PROJECT COMPLETION REQUIREMENT: All projects must be completed and turned-in at the beginning of class on the scheduled due dates. In addition, a confidential performance appraisal must also be turned-in by each student. Failure to complete a project, report, or paper will cause each team member to receive a course grade of "F," regardless of the point weighting assigned to that project.

APPRAISAL:

Cases, Quizzes, Class Participation, & Presentations.	40%
Mid-term Exam.	30%
Comprehensive Final. . . .	30%

Grade Scale:

A	91 - 100%
B	81 - 90%
C	71 - 80%
D	61 - 70%
F	below 61%

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
FALL 1997

1. **Finance 645: Financial Theory and Analysis**

2. **Prerequisite: Finance 545 or equivalent. Accounting 673 is recommended.**

3. **Texts:**

Cases purchased through the COB Copy Center on the second floor of Showker Hall are required and will be available by next Monday.

Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, Eighth Edition. (Dryden Press, 1997). This text will be used as a reference book. There will be suggested reading assignments from this book. If you use the seventh edition or another text, cross reference the reading assignment and review the related material prior to the class.

4. **Course Objectives:**

To understand how to perform a financial and cash flow analysis of an enterprise (1,2,3,8,9,10)
To construct pro-forma financial statements (1,5,10)
To understand the concepts of risk and return (1,2,3,4,8)
To determine a firm's cost of capital (1,2,3,6,8,9)
To use various asset acquisition evaluation methods (3,4,6,9)

5. **Topics Covered:**

a. Financial Analysis
b. Cash Flow Analysis
c. Industry Characteristics
d. Cash Budgeting
e. Working capital management
f. Cost of Equity
g. Weighted Avg. Cost of Capital
h. Capital Budgeting
I. Risk & Capital Budgeting
j. Pro-forma statement construction

6. **Purpose of Projects or Cases**:

a. Demonstrate a knowledge of the process required to solve the type of problem presented in the project or case.

b. Develop skills using financial and analytical tools.

c. Demonstrate a mastery in the use of the tools by:
   1. Recognizing the information and data required and
   2. Making reasonable assumptions when data is not available.

d. Demonstrating the ability to make "informed judgements" from the information obtained in the analysis.

7. **Team Presentations:**

Case presentations will be assigned to teams. Each team is responsible for two cases -- one as a consulting team and the other as a management team.

8. **Role of the Consulting Team and the Management Team:**

The consulting team is responsible for presenting and using a methodology for solving the problems that are addressed in the assigned case. The objective is to assure that the class members are knowledgeable about the application and use of the methodology.

The role of the management team is to ask questions and to make suggestions during the presentation. Their role is to assure that the consulting team's presentation is correct and to add reinforcement to the use and application of the methodology conveyed by the case.

9. **General Analytical Procedure for case analysis by the consulting and management teams**:

   a. Determine the problem or topic to be analyzed.
   b. Assess how the economic environment at the time of the case that relates to the problem to be solved. For example, if it appears the economy is entering a recession, that should be considered in the revenue forecast. Only consider those economic data that are pertinent to the analysis.
   c. Analyze the financial impact of possible decisions. The analysis often takes the form of a pro-forma statement for each scenario.
   d. Evaluate the impact of the scenario. This evaluation ;should incorporate financial impacts (as measured by NPV, IRR, etc) and should also examine qualitative issues.
   e. Consider the underlaying assumptions in the development of each scenario. The assumptions often have to be made given limited information. Are these assumptions reasonable?
   f. Make a decision.

10. **Class Appraisal of Presentations:**

The consulting and management presentations will be graded using both peer and instructor appraisal. The peer appraisal forms will be supplied at a later date. The instructors grade will be based on his questioning the class members in the audience to determine their level of understanding of the material that is being presented. The peer appraisal should be done based upon your assessment of your ability to answer questions developed from the case presentation.

11. **Class Participation:**

Class participation counts 20% of the course grade. This portion of your grade will consist of your one-page case write-ups and your participation in class discussion. You get credit for discussion of projects, cases, or other materials; contributing to the presentation by asking insightful questions; or by answering questions asked by another student.

12. **One-page Written Reports:** The assigned projects and cases must be written-up and handed-in. A general outline for the one-page write-ups is shown on the next page.

a. A statement indicating the problem that needs to be addressed.
b. The recommended quantitative analytical method used to resolve the problem and a brief paragraph describing the analytical method.
c. A brief listing of the data requirements of the analytical method (no more than the five most important items.)
d. A listing of the three most important qualitative facts in the case.

13. **Appraisal:**

Class Participation and one page case reports	20%
Presentations and Written Reports	25%
Mid-term Exam	25%
Final Exam	30%

15. **Grading Scale:**

A - 91-100%
B - 81-90%
C - 71-80%
F - 70 or below

16. **Office Hours:**

Monday:	1:00-2:00
Tuesday:	9:30-1:30

Occasionally I will not be available during these hours. The preferred method of contact is by e-mail.

17.. **E-mail address:** WEAVERCG
Office: Showker 344
Telephone: Office (540) 568-3080
Home (540) 833-1461

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
Spring 1998

1. Finance 488: Advanced Financial Policy

2. Prerequisite: Finance 365.

3. Texts and materials:

Cases to be purchased from the COB Copy Center.

Hand-out notes to be purchased from the COB Copy Center.

Reference text: Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, Eighth Edition. (Dryden Press, 1997). This text is not required. You may use the same text used in your Finance 365 course.

4. Topics to be covered:

1.	Financial Analysis	7.	International Finance
2.	Capital Budgeting	8.	Investment Analysis
3.	Capital Structure	9.	Lease vs. Buy
4.	Cost of Capital	10.	Small Business Finance
5.	Cost of Equity	11.	Valuation of a Business
6.	Derivatives and SWAPS		

5. Purpose of Project or Case:

A. Demonstrate a knowledge of the process required to solve the type of problem presented in the project or case.

B. Develop skills using financial-analytical tools.

C. Demonstrate a mastery in the use of the tools by:
   1. recognizing the information and data required; and
   2. making reasonable assumptions when data is not available.

D. Demonstrate the ability to make "informed judgements" from the information obtained in the analysis.

6. Case Presentations:

Case presentations will be assigned to student teams. Each team is responsible for presenting two cases. Students not making a case presentation are required to hand-in a one-page report on the case.

7. Class Participation:

Class participation counts 20% of the course grade. This portion of your grade will consist of one-page case outlines and participation in class discussion on case materials.

8. One-page Reports:

The one-page reports are required to be in outline form. A team performing a presentation will hand in a hard copy of the presentation and visual aids rather than the outline. NO Papers will be accepted late.

I. Problem Statement - a brief and concise statement or question that indicates the problem that needs to be addressed in a decision statement.

II. Analytical Method - the recommended analytical tool used to provide information for making a decision. A brief description of that tool in three or four sentences should be included.

III. Data Requirements - a listing of the data required and contained in the case that are needed to implement the analytical method.

IV. Qualitative Facts - a listing of the three most important qualitative facts from the case that must be considered in the decision recommendation that resolves the problem.

9. Appraisal of Presentations: The presentations and class participation grades will be assigned by the instructor using the following criteria:

"A" presentation -

- Professional presentation that contains NO errors.
- Visual aids in color constructed using power point or other current technology.
- Presenters appear to have a high degree of expertise in the case subject matter.
- Presenters are "self-starters" in researching case material from text and other sources and have relied on a minimal "hand-holding" from me or other instructors. (Treat this as if you have been given an assignment by your employer.)
- Presenters provide the class a hand-out where appropriate to help follow the presentation and to assist in their development of expertise in the subject matter.

"B" presentation -

- Presentation contains one error, or
- One of the above "A" criteria items is not in compliance.

"C" presentation-

- Presentation contains two errors, or
- Some combination two of the items required for an "A" presentation is missing.

"D" presentation -

- Some combination of three of the items required for an "A" is lacking.

"F" presentation -

- Some combination of four of the items required for an "A" is lacking.
- An "F" presentation score will be recorded as a 40.

10.	Attendance:	Class attendance is expected. Your final average will be lowered one letter grade for each absence in excess of TWO for each unexcused absence. An attendance sheet will be used and the honor system will be in effect concerning signing the sheet. The possibility of having an absence excused is slim to none.	
11.	Appraisal:	One-page write-ups & Class Participation	20%
		Presentations & Reports	30%
		Mid-term Exam	20%
		Final Exam	30%
12.	Grading Scale:	A - 91-100%	D - 61-70%
		B - 81-90%	F - 60% or below
		C - 71-80%	
13.	Office Hours:	Tuesday:	3:00 -4:00
		Wednesday:	10:00 - 12:00
		Thursday:	9:30 - 10:30
14.	E-mail address:	WEAVERCG	
	Office:	Showker 344	
	Telephone:	(540) 568-3080	

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
Spring 1998

1. **Finance 655: Advanced Topics in Financial Management**

Financial theory and analytical techniques are applied to business problems in a case environment. The objective is to determine optimum decisions based upon an integration of financial, accounting, economic, and behavioral factors.

2. **Prerequisite: Finance 645.**

3. **Texts:**

Cases that are purchased through the instructor.
Packet purchased from COB Print Shop.
Text: Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, 8th Edition. (The Dryden Press, 1997).

4. **Topics to be Covered:**

SWAPS
Valuation
Capital Structure
Dividend Policy
Venture Capital
Bankruptcy and Reorganization
Mergers and Acquisitions
The creation and destruction of value

5. **General Analytical Procedure:** (not all steps can be done for each case)

A. Determine the problem or topic to be analyzed.
B. Examine Economic Data for period of case.
C. Do a financial and cash flow analysis to determine the financial condition of the company being analyzed.
D. Construct a pro-forma statement that will reflect and provide information about the scenario being examined.
E. Use pro-forma statement to do sensitivity analysis showing different alternative decisions.
F. Do a financial and cash flow analysis on the pro-forma results to obtain information about each alternative.
G. Attempt to estimate the qualitative results of the alternative decisions on the firm. (Value; financial flexibility, risk, control, employees, customers, suppliers, etc.)
H. Make the decision.

6. **Team presentations:**

Each team is responsible for two cases and one article. One of the cases will be presented as a consulting team and the other will be prepared to question the presentation as a management team. The article will be prepared as a presentation.

7. **Role of the Consulting Team and the Management Team:**

The consulting team is responsible for presenting the case. The role of the management team is to ask questions and to make suggestions during the presentation. The intended result of this dialogue is to enhance the class's understanding of the material that is presented. The teams should prepare the case independently of one another.

The Management Team's questions and comments should be directed toward: clarifying the analytical method being used; identifying and questioning the assumptions that are being made in the analysis; helping focus on the implications of the results on owners, management, employees, suppliers, customers, the community or other stakeholders; etc.

8. Case Presentation Outline:

The assigned cases must be outlined and handed-in by their respective consulting and management teams. A suggested guide for the outline that can generally be used is given below.

Suggested Outline for Cases

I. Problem or objective statement:
  A. Phrased as a question, or;
  B. Major financial task that needs to be addressed.

II. Economic environment at time of case that relates to the problem or objective should be considered. You should be aware of how the economic conditions will effect the topic or problem undergoing examination. For example, if it appears the economy is entering a recession, that should be considered in the revenue forecast. Only consider those economic data that are pertinent to the analysis.

III. Method of Analysis:
  A. Description of new analytical financial tools that are being used.
  B. Explanation how the quantitative tools will be applied. The presentation should provide sufficient explanation so that the class is trained in the use of the tools.
  C. Description of the qualitative considerations.

IV. Analysis:
  A. Describe the results of the implementation of the analytical tools.
  B. Address both the quantitative and qualitative issues.

V. Conclusion: Be certain to address the problem statement or objective set forth in item I above and support your conclusion with the results of your analysis.

9. Class participant responsibility:

Each class participant must turn-in a one-page report for each case which contains the following information:

I. A statement indicating the problem that needs to be addressed.
II. The recommended quantitative analytical method used to resolve the problem.
III. A brief paragraph describing the analytical method.
IV. A brief listing of the data requirements of the analytical method (no more than 5 of the most important items).
V. A listing of three most important qualitative facts in the case.

9. Appraisal:

Cases and Article Presentations @15% each	45%
Written Case Outline @ 10% each	20%
Class Participant Reports	10%
Class Discussion Participation	5%
Take-home Final	20%

10. Grading Scale:

A - 91-100%
B - 81-90%
C - 71-80%
F - 70 or below

11. Office Hours: Monday & Thursday: 9:30-11:30

12. Telephone Number: JMU - (540) 568-3080
Home - (540) 433-9288

13. E-Mail Address: WEAVERCK

JAMES MADISON UNIVERSITY
DEPARTMENT OF FINANCE & BUSINESS LAW
SUMMER 1998

1. Finance 488: Advanced Financial Policy

2. Prerequisite: Finance 365.

3. Texts:

Cases to be purchased from the COB Copy Center (these will be available after 5/8/97).

Reference text: Eugene F. Brigham and Louis C. Gapenski, Financial Management, Theory and Practice, Eighth Edition. (Dryden Press, 1997). This text is not required. You may use the same text used in your Finance 365 course.

4. Topics to be covered:

1.	Financial Analysis	7.	International Finance
2.	Capital Budgeting	8.	Investment Analysis
3.	Capital Structure	9.	Lease vs. Buy
4.	Cost of Capital	10.	Small Business Finance
5.	Cost of Equity	11.	Valuation of a Business
6.	Derivatives and SWAPS		

5. Purpose of Project or Case:

A. Demonstrate a knowledge of the process required to solve the type of problem presented in the project or case.

B. Develop skills using financial-analytical tools.

C. Demonstrate a mastery in the use of the tools by:
   1. recognizing the information and data required; and
   2. making reasonable assumptions when data is not available.

D. Demonstrate the ability to make "informed judgements" from the information obtained in the analysis.

6. Team Presentations:

Case presentations will be assigned to teams. Each team is responsible for presenting one case. The instructor will call on students in the class to elaborate point made in the presentation.

7. Class Participation:

Class participation counts 15 % of the course grade. This portion of your grade will consist of one-page case outlines and participation in class discussion.

8. One-page Outlines:

An outline for the one-page reports, which is to be turned-in on the day indicated in the syllabus, is shown below. A team performing a presentation will hand in a hard copy of the presentation outline and visual aids. NO Papers will be accepted late.

I. Problem Statement - a statement or question that indicates the problem that needs to be addressed in a decision statement.

II. Analytical Method - the recommended analytical tool used to provide information for making a decision and a brief description of that tool.

III. Data Requirements - a listing of the data required to implement the analytical method (no more than the five most important items.)

IV. Qualitative Facts - a listing of the three most important qualitative facts that must be considered in the decision recommendation that resolves the problem.

9. Class Appraisal of Presentations:

The presentations and class participation grades will be assigned by the instructor. The presentations are expected to be professional, informative, accurate, and demonstrate expertise in the topic being examined. The class participation grades will be based on questions asked by students and by the instructors questioning the class members in the audience to determine their level of understanding of the material that is being presented.

10. Attendance: Class attendance is expected. Your final average will be lowered one letter grade for each absence in excess of ONE for each unexcused absence. You are expected to attend all of the classes in this session. No absences will be excused except under EXTREME circumstances.

11. Appraisal:

One-page write-ups & Class Participation	15%
Presentations & Reports	25%
Four Weekly Exams	60%

12. Grading Scale: A - 91-100% D - 61-70%
B - 81-90% F - 60% or below
C - 71-80%

13. Office Hours: Monday: 1:00-230
Tuesday: 1:00-2:30

14. E-mail address: weavercg@jmu.edu
Telephone: (540) 568-3080
Office: Showker 344

15. Class Citizenship: Take care of your personal business prior to class. Any student who, in the instructor's opinion, demonstrates disrespect to other students

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
Request for Information by
Western Kentucky Gas Company

2. Please provide the list of textbooks that Dr. Weaver used in the last five years of teaching finance.

Answer:

Fundamentals of Corporate Finance, Stephen A. Ross, Randolph W. Westerfield, and Bradford D. Jordan, McGraw-Hill, 1998.

Financial Management, Theory and Practice, Eugene F. Brigham, Louis C. Gapenski, and Michael C. Ehrhardt*, The Dryden Press, 9th Edition - 1999
8th Edition - 1997
7th Edition - 1995

*Ehrhardt became a co-author with the 9th edition.

Fundamentals of Financial Management, Eugene F. Brigham and Joel F. Houston, The Dryden Press, 7th edition, 1995.

Darden Case Bibliography, 1995-96, 1996,97, 1997-98. Individual cases were purchased from Darden Educational Materials Services for class use.

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
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3. Refer to Schedules 24 and 25 of Dr. Weaver's Direct Testimony. Is the market return using the Value Line data that Dr. Weaver uses calculated using a geometric average or an arithmetic average? If the Market Return is a geometric average, please cite sources from referred journals that prescribe the use of a geometric average when calculating a market return.

Answer: A geometric mean was used to determine a one year growth rate from the August 27 Appreciation Potential which was 65%.

The calculation was: $[(1.65)^{1/4} - 1]$ = annual rate.

This assumes that price appreciation growth occurs at a compound rate which is a correct assumption when considering growth over a period of years. A good discussion of this can be found in an investment management text book by Henry Latane and Donald L. Tuddle. This book dates from the late 1960's or early 1970. I no longer have it in my possession. Ibbotsen at one time discussed the proper use of a geometric mean to determine a growth rate versus an arithmetic mean to determine a descriptor of a population of data in the SBBI Handbook.

Commonwealth of Kentucky
Before the Public Service Commission
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Responses by Carl G. K. Weaver to
Request for Information by
Western Kentucky Gas Company

4. Please refer to Schedules 24 and 25 of Dr. Weaver's Direct Testimony. Please provide the work papers and source documents used to calculate the Standard & Poor's Market Return.

Answer: The 16.1% S&P return was used as the return on the index from FY 99 to FY 98. This was used as being higher the 15.8% forecast for its growth over the next five years. Data for the index return was compiled by I/B/E/S and reported by Compact Disclosure. This data is provided in the printouts of source data supplied to the Commission to their request in question 19.

Commonwealth of Kentucky
Before the Public Service Commission
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Responses by Carl G. K. Weaver to
Request for Information by
Western Kentucky Gas Company

5. Refer to page 10, lines 13-17 of Dr. Weaver's Direct Testimony. He states:

> "...I next examined the market service area that is reported by Value Line for the fifteen remaining companies. I eliminated AGL Resources, Peoples Energy Corporation, and Washington Gas Light because the service are for these companies are concentrated in Atlanta, Chicago, and Washington, D.C. - all urban areas, far different from the service area of Western Kentucky."

a. Is it Dr. Weaver's opinion that a gas distribution company which has its service area concentrated in St. Louis, MO. Is comparable to Western Kentucky? Please explain.

b. Did Dr. Weaver choose to include New Jersey Resources because its service territory is concentrated in ;Monmouth and Ocean Counties, New Jersey?

c. In Dr. Weaver's opinion, which company has the larger geographic service territory, AGL Resources or New Jersey Resources?

Answer:

A. Laclede was selected because, according to Value Line, "Laclede Gas company is a regulated utility that distributes natural gas in eastern Missouri (population, 2 million), including the city of St. Louis, St. Louis County, and parts of 8 other counties." In choosing companies to use to obtain data, I eliminated companies whose territories were strictly in an urban area. This company was not eliminated because its territory included "parts of 8 counties."

B. New Jersey Resources serves a "central and southern New Jersey territory that is undergoing a shift from rural to suburban and from seasonal to year-round residences." (Value Line, September 24, 1999) I am aware of the rural nature of southern New Jersey having spent two years there during my military service. The selection criteria that I used are shown on page 10 of my Direct Testimony.

C. I did not consider the size of the geographic territory that was served. However, I did consider whether it was nearly 100% urban or not.

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SET I

6. With respect to the rate base adjustments:

   a. Why did Mr. Morgan not use the updated capital budget submitted in response to KPSC DR 4-2 (formerly KPSC DR 3-58) as the baseline capital budget for his adjustments?

   b. What is the basis for Mr. Morgan's adjustment to "0" of all System Maintenance - Retirements and System Improvements - Public Works Reimbursements, given, for example, Western's response to KPSC DR 2-21b and KPSC DR 3-43c?

   c. Why was an overhead factor applied to the projected forfeitures, given Western's response to KPSC DR 2-21 and KPSC DR 3-43?

   d. Why did Mr. Morgan use a ratio of 16% for Div 02 Shared Services Plant Allocations, when he consistently used 16.75% in all of his other calculations?

   e. Aside from the issues referenced in a. through d. above, is Mr. Morgan aware of any unspecified adjustments that would further reduce rate base by $300,000?

<u>Response</u>

a. The detailed information was not available to calculate the plant in service balance based upon the 92 percent ratio instead of the 94 percent ratio.

b. Since there were no account numbers assigned to System Maintenance-Retirements and System Improvements-Public Works Reimbursements, the amounts in those accounts were spread over the other accounts in each category (System Improvements or System Maintenance) that had projected capital expenditures associated with them during the forecast period on a pro rated basis.

Response 6 (cont'd.)

c. At time of testing the spreadsheet, the attempt was to follow the Company's method as closely as possible to ensure that similar amounts would result. Due to an oversight, the Company's error was not changed.

d. At the time of preparing the spreadsheet, the workpapers in Volume 10, Tab 15 of the Company's filing was followed. In order to ensure similar amounts resulted from the calculation, the 16 percent was used as indicated on the workpapers. Due to an oversight, the 16 percent was not changed.

e. No.

Responsible Witness: Lafayette K. Morgan, Jr.

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7. Please provide support for the use of the 92% adjustment factor applied to Western's capital budget.

Response

Please see the attached schedule.

Responsible Witness: Lafayette K. Morgan, Jr.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 190
Witness: David H. Doggette

Data Request:

190. With reference to the discussion in Mr. Doggette's testimony relative to the control and monitoring of capital expenditures:

   a. Please explain whether the spending on any capital projects is affected when other capital projects exceed their approved funding levels. If so, please explain fully how spending on capital projects is interrelated.

   b. In instances where projects are delayed during a given fiscal year, are the approved funds available for use on other projects? If so, is there is a separate approval process for the shifting of funds? Please explain.

   c. Please explain the decrease in the capital budget between FY 1997 and FY 1998.

Response:

a. Western manages the capital budget on a project basis. However, the capital budget is developed beforehand when all particulars of a project may not be known. Western also works towards managing within the overall fiscal year capital budget.

b. When projects are delayed, they must be budgeted again in the fiscal year in which they are anticipated to occur. If it is deemed prudent to utilize capital funds for other projects, those projects are submitted through the approval process.

c. It should be noted at this point that a revision to the table shown on page 8 of the testimony of David H. Doggette is necessary. The capital budget amounts shown for the 1994-1997 fiscal years include overheads. The amounts stated for 1998 do not include the applicable overhead amounts. The table is revised and restated to show overheads included for all years on Schedule AG DR1 190 attached.

   The FY 1997 to FY 1998 decrease in capital budget is related to non-recurring projects, highway relocation projects, computer purchases, vehicle purchases, and reduced non-direct charges. Refer to page 8 of the testimony of David H. Doggette. Also refer to KPSC DR1-28, pages 18 through 28 and AG IDR 225.

SCHEDULE AG DR1-190

Revised - Western's Historical Capital Expenditures

Fiscal Year	Actual Dollars	Budgeted Dollars	Over/(Under) Budget, $'s	Variance (%)
1998	$ 11,459,605	$ 10,194,434	$ 1,265,171	12.4%
1997	$ 15,085,222	$ 16,595,351	$ (1,510,129)	-9.1%
1996	$ 14,253,519	$ 17,770,374	$ (3,516,855)	-19.8%
1995	$ 15,458,055	$ 16,592,170	$ (1,134,115)	-6.8%
1994	$ 10,872,491	$ 11,453,427	$ (580,936)	-5.1%

67,128,892 72,605,756

.92

Total Actual $ 1994 - 1998 67,128,892 = .92

Total Budgeted $ 1994 - 1998 72,605,756

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8. Based upon the information in the table below:

Fiscal Year	Capital Budget	Actual Spending	Percent Spent
1990	$ 7,339,009	$ 7,155,701	97.5
1991	8,594,319	7,454,806	86.7
1992	10,129,578	9,870,231	97.4
1993	9,323,533	9,864,309	105.8
1994	11,453,427	10,872,491	94.9
1995	16,592,171	15,458,057	93.2
1996	17,770,373	14,254,212	80.2
1997	16,595,360	15,085,222	90.9
1998	10,194,434	11,459,605	112.4
	$107,992,204	$101,474,634	
	1990-1998 Average Percentage Spent		95.5

a. Does Mr. Morgan agree that the average annual percentage of capital spent versus budget from 1990 to 1998 (that is, an average of the annual percentages) is 95.5%7[sic]?

b. Does Mr. Motion [sic] agree that the years 1995, 1996 and 1997 represent both the highest level of annual direct capital budgets and direct capital expenditures, between S14 [sic] and $18 million, incurred by Western between 1990-19987 [sic]?

c. Does Mr. Morgan agree that the range of actual and budgeted expenditures between 1990-1998, excluding 1995-1997, is between $7 and $12 million?

d. Does Mr. Morgan agree that the percentage of actual annual capital expenditures versus annual capital budget is lowest in the years 1995, 1996 and 1997, with the exception of 1991?

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Data Request 8 (cont'd.)

e. Does Mr. Morgan agree that when the years 1995, 1996 and 1997 are removed from the calculation of the average annual percentage of actual annual capital expenditures versus annual capital budget (an average of the annual percentages), the result is an average of 99.1%?

f. Does Mr. Morgan agree that direct capital budgets for Western from 1999 to 2001 are between $7 million and $12 million, and not between $14 million and $18 million?

g. Based upon the response to the [sic] a through f above, is it not more likely that Western's percentage of actual annual capital expenditures to budget would more likely approximate 99.1% than 92%?

Response

a. Based on an average of the annual percentages from 1990 to 1998, the result is 95.4 percent. The average based on actual total expenditures and budgets is 93.9 percent.

b. The years 1995, 1996 and 1997 represent the highest level of total capital expenditures for 1990 through 1998. I have not reviewed the detailed data to be able to state that these are highest level of "direct" capital expenditures.

c. Yes.

Responsible Witness: Lafayette K. Morgan, Jr.

Response 8 (cont'd.)

d. Yes.

e. Based on an average of the annual percentages, the result is 99.1 percent.

f. The total capital budgets for 1999 to 2001 are between \$7 million and \$12 million.

g. No. There is no correlation between the expenditure level and the percentage spent.

Responsible Witness: Lafayette K. Morgan, Jr.

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9. Does Ms. [sic] Morgan disagree that Western's average annual capital budget from 1999-2003 is approximately 88.6% of the average annual capital budget for 1990-19987 [sic]?

Response

Based upon the data I have, the 1999-2003 average budget is 80.6 percent of the average budget for 1990-1998.

Responsible Witness: Lafayette K. Morgan, Jr.

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10. With respect to the adjustment made to overheads:

a. In general, is it likely that the addition of one typically sized capital project in a given year is likely to significantly increase Western's overhead costs?

b. In general, is it likely that the deletion of one typically sized capital project in a given year is likely to significantly decrease Western's overhead costs?

c. Does Mr. Morgan generally agree that the nature of overhead costs, including executive, engineering, supervisory and clerical costs, is that they are more fixed components of costs and, therefore, are generally less avoidable than the capital projects to which they are applied?

d. If the answer to c. above is yes, given the more fixed nature of overhead costs, why is it not reasonable that the percentage of overheads to direct costs would increase as direct costs decline?

e. If the answer to c. above is no, please explain.

f. Does Mr. Morgan agree that Western's capital overheads ranged from $4.1 million to $5.6 million from 1996 to 1998, but are forecasted by Western to range from $2.9 million to $3.5 million during 1999 to 20037 [sic]?

g. Does Mr. Morgan agree that Western is projecting a decline in its capital overheads from 1996-1998 to 1999-2003?

<u>Response</u>

a.,b.&c. Generally, the nature of overhead costs is that they are fixed and less avoidable than direct capital expenditures. In general, the addition or deletion of one typical size project is not likely to significantly change overhead costs.

Response 10 (cont'd.)

d. The actual overhead amounts have declined from 1996 to 1999. Given that overheads are more fixed than direct construction expenditures, overheads as a percentage of direct construction expenditures will decrease as construction expenditures increase. This decrease should be reflected in the budget. For instance, if the FY 1999 overheads are held constant, they represent 43 percent of the 2003 budgeted direct capital expenditures. The assumption for holding the overhead constant is reasonable given the Company is projecting that its O&M will remain flat. These overheads are similar to O&M expenses, and in many cases, they represent a portion of O&M expenses charged to construction.

e. N/A.

f. Yes.

g. Yes, but the overheads are based upon a 50 percent ratio which overstates the overheads.

Responsible Witness: Lafayette K. Morgan, Jr.

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11. With respect to the "structures and improvements" adjustment:

a. To what types of projects does Mr. Morgan intend to apply: buildings and offices, or remedial work applicable to piping systems providing for public safety and reliable service?

b. If the answer to a. above includes remedial work applicable to piping systems, how does he rationalize this with Western's response to AG DR 2-5?

c. Did Mr. Morgan intend to eliminate the incremental increase in spending above 1999 levels on all specific projects associated with remedial work on piping systems providing for public safety and reliable service?

d. Western's average annual expenditure in system maintenance and improvements in its 1990-1998 [sic] was $4,011,505. If related spending in 1999 was reduced to $2,926,403 due to a planned one-time reduction in such expenditures due to the transition to new systems, including the Oracle financial project, is it not reasonable that Western would plan to increase its spending on such projects in subsequent years after the transition?

Response

a.-d.) The adjustment to structures and improvements was to remove the additional expenditures associated with the 36.25 percent factor. From the data Western has provided, Western has included a level of structures and improvement based on the base approach and is also adding additional expenditures for certain projects. Western has not provided any data that show that the additional expenditures are not covered by the "baseline" expenditures.

Responsible Witness: Lafayette K. Morgan, Jr.

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12. Western's response to Supplemental Response to KPSC DR 1-6 includes the net effects of the United Cities merger with Atmos.

   a. With respect to the adjustment for merger and integration expenses, does Mr. Morgan deny that Western's ratepayers will benefit from this merger?

   b. Does Mr. Morgan agree that Western's allocation of Shared Services expenses declined from about 22% prior to the merger to about 18% after the merger?

   c. Given Western's return during the test year, what is the savings the shareholders "enjoy" if the Company does not earn a reasonable return?

<u>Response</u>

   a. No.

   b. Yes.

   c. The benefits are not limited to one period. Atmos Management has acknowledged that there are long term benefits to be achieved from the merger.

<u>Responsible Witness</u>: Lafayette K. Morgan, Jr.

13. With respect to Mr. Morgan's lawsuit settlement adjustment:

    a. Does Mr. Morgan agree that annual liability insurance premiums may vary with the annual retention (the deductible)?

    b. Does Mr. Morgan agree that liability insurance premiums are a recoverable expense?

<u>Response</u>

a. Yes.

b. Yes.

Responsible Witness: Lafayette K. Morgan, Jr.

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14. With respect to the pension expense adjustment:

a. Is Western's pension credit a source of cash Western can apply to its daily operations in providing service to its customers?

b. If Western's annual net periodic pension cost becomes positive does Mr. Morgan believe that Western is or is not obligated to contribute cash to the pension plan?

c. If Western's annual net periodic pension cost were a $27 million credit due to the performance of plan assets, would Mr. Morgan recommend that no annual operating expenses be recognized in the setting of Western's rates?

Response

a. No. However, if rates are based upon a level of pension expense that is higher than the actual expense, the Company will receive a windfall.

b. Yes.

c. The recommended level of operating expenses would be on the SFAS 87 pension expense amount.

Responsible Witness: Lafayette K. Morgan, Jr.

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15. On schedule LKM-17, did Mr. Morgan intend to apply depreciation expense at 100% ignoring Western's standard practice of capitalizing 4.55% of depreciation?

Response

It is not my intention to ignore the portion of depreciation expense capitalized.

Responsible Witness: Lafayette K. Morgan, Jr.

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16. Provide all workpapers and supporting documents not previously provided.

Response

There were no other workpapers.

/2781/lkm/datareq/ag_response.wpd

Responsible Witness: Lafayette K. Morgan, Jr.

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17. Reference pages 8-9 of Mr. Galligan's testimony and his reference to excerpts from Bonbright's Principles of Public Utility Rates, pages 347-348. Does that reference provide specific opinions on how to allocate "distribution costs?" If yes, provide the excerpts regarding those comments.

Response

It is Mr. Galligan's recommendation that, in a strict sense, Professor Bonbright believes the referenced costs are unallocable in a marginal cost study, but they must, somehow, be allocated in an average cost study. This allocation should be on the basis of cost causality. After discussing the controversy of several allocation methods, the author does not endorse any particular method. Mr. Galligan is out of the country and will update this response, if necessary, after reviewing the Bonbright text.

Responsible Witness: Richard A. Galligan

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18. Please provide the workpapers associated with Mr. Galligan's cost of service study summarized in RAG-1.

Response

Please see the attached workpapers.

Prepared by: Jerome D. Mierzwa

Responsible Witness: Richad A. Galligan

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE OF RETURN AT PRESENT RATES
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.	Cost Item	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)
1	Total Operating Margins	44,842,983	24,208,630	10,071,538	1,234,217	3,880,223	5,448,375
2							
3	O & M Expense	23,121,835	13,019,693	5,765,974	447,291	1,232,167	2,656,709
4							
5	Deprec. & Amortization	6,486,839	3,117,681	1,484,459	176,974	507,583	1,200,144
6							
7	Property & Other Taxes	1,908,720	917,290	438,898	53,314	149,093	350,127
8							
9	Interest	4,754,687	2,438,450	1,143,065	116,930	322,474	733,767
10							
11	Pre-Tax Expenses	36,272,081	19,493,114	8,832,396	794,509	2,211,316	4,940,746
12							
13	Taxable Income	8,570,902	4,715,516	1,239,142	439,708	1,668,907	507,629
14							
15	Income Taxes	3,459,430	1,903,300	500,149	177,477	673,612	204,892
16							
17	Return	9,866,159	5,250,666	1,882,058	379,161	1,317,769	1,036,504
18							
19	Rate Base	124,468,624	63,833,971	29,923,254	3,061,015	8,441,759	19,208,626
20							
21	Rate Of Return	7.93%	8.23%	6.29%	12.39%	15.61%	5.40%

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE CLASS COMPARISONS

Line No. Description	Firm Residential (a)	Firm Commercial (b)	Firm Industrial (c)	Interr. & Carriage (d)	Large Int. & Carr. (e)
1 Average Annual Use Per Customer	86.2	371.2	7,414.7	53,027.2	1,000,011.3
2 Winter Season as a % of Annual Use	73.8%	70.2%	58.9%	46.7%	45.2%
3 Class Load Factor Average Day / Design Day	20.7%	21.1%	32.4%	36.2%	56.8%

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE BASE - SEPTEMBER 30, 1998

Line No.	Item	Total	Gas Cost	Storage	Distribution	Transmission	Production	Notes
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Gas Plant	$203,141,249	$114,003	$5,518,920	$167,199,269	$29,373,900	$935,157	[1]
2	In Progress	17,179,026	10,307	467,270	14,140,056	2,484,087	77,306	[2]
3	Storage Cushion	1,694,833		1,694,833				[3]
4	Acquisition Adjustment	0	0	0	0	0	0	[1]
5	Material & Supplies	887,889		0	843,495	44,394		[7]
6	Gas Stored Underground	8,704,155		8,704,155				[4]
7	Prepayments	430,296	258	11,704	354,177	62,221	1,936	[1]
8	Prepaid Gas Purchases	166,569	166,569					[4]
9	Cash Requirements	2,890,229	44,510	58,094	2,678,954	108,095	576	[5]
10								
11		235,094,246	335,647	16,454,976	185,215,951	32,072,697	1,014,975	
12								
13	Deduct:							
14	Reserves:							
15	Deprec. & Amort.	94,938,460	6,772	3,764,514	74,025,104	16,307,871	834,198	[2]
16	Deferred Income Taxes	10,125,213	6,075	275,406	8,334,063	1,464,106	45,563	[1]
17	Customer Advances Const.	5,562,323			5,284,207	278,116		[6]
18								
19		110,625,996	12,847	4,039,920	87,643,374	18,050,093	879,761	
20								
21								
22	Rate Base	124,468,251	322,801	12,415,055	97,572,577	14,022,604	135,214	

Notes [1] Allocated By Gross Plant Percentage, See Sheet 1
[2] Identified Where Possible, Residual Allocated By Gross Plant Percentage, See Sheet 1
[3] Per Books
[4] Working Gas, test year average
[5] One Eighth O & M, Spread By O & M Percentage, Not Including Cost Of Gas, See Sheet 1
[6] 95% Distribution, 5% Transmission
[7] Fuel Stock To Storage Function; Balance, 95% Distribution, 5% Transmission

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE BASE - CLASSIFICATION

Line No.	Item	Total	Customer	Demand	Commodity	Direct	Notes
		(a)	(b)	(c)	(d)	(e)	(f)
1	Gas Cost	$322,801		$156,232	$166,569		[1]
2							
3	Storage	12,415,055		6,207,528	6,207,527		[2]
4							
5	Distribution	97,572,577	50,357,207	23,573,535	21,631,840	2,009,995	[3]
6							
7	Transmission	14,022,604		14,022,604			[4]
8							
9	Production	135,214		135,214			[4]
10							
11							
12	Total Rate Base	124,468,251	50,357,207	44,095,113	28,005,936	2,009,995	

Notes [1] Prepaid Gas Purchases Are All Commodity, Remainder All Demand
[2] 50% Demand, 50% Commodity
[3] Based On Distribution Plant Accounts, See Sheet 2
[4] 100 % Demand

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of RATE BASE to Classes of Service

Line No.	Item	Alloc. Factor [2]	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Gas Cost	A&P/Gas	$156,232	$92,333	$48,338	$8,499	$4,109	$2,953
2		Sales	166,569	94,212	50,087	10,794	10,144	1,332
3			322,801	186,545	98,425	19,293	14,253	4,285
4								
5	Storage	Design-B	6,207,528	3,817,009	1,989,513	312,859	32,900	55,247
6		Winter	6,207,527	2,139,114	1,081,351	219,746	700,209	2,067,107
7			12,415,055	5,956,123	3,070,864	532,605	733,109	2,122,354
8	Distribution [1]							
9	Mains	Vol-A	21,631,840	5,762,722	3,063,069	741,972	2,980,868	9,083,210
10		Design-A	21,635,790	8,751,677	4,562,988	718,308	2,587,641	5,015,176
11								
12	Services	Cust-D	28,023,786	19,913,702	8,110,084	0	0	0
13								
14	Meters	Cust-M	11,874,229	8,149,283	3,318,847	260,046	146,053	0
15								
16	Other	Cust-C	10,459,552	6,836,363	3,374,251	40,792	115,055	93,090
17		Design-A	1,937,756	783,822	408,673	64,334	231,756	449,172
18								
19	Direct - Other	Cust-E	2,009,995	0	0	25,326	1,097,859	886,810
20								
21	Total Distribution		97,572,950	50,197,569	22,837,913	1,850,778	7,159,232	15,527,458
22								
23	Transmission	A&P	14,022,604	7,422,164	3,878,652	652,051	530,054	1,539,682
24								
25	Production	A&P	135,214	71,569	37,400	6,287	5,111	14,847
26								
27	Total Rate Base		124,468,624	63,833,971	29,923,254	3,061,015	8,441,759	19,208,626

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
GAS COST - CLASSIFICATION

Line No.	Item	Total	Customer	Demand	Commodity	Direct	Notes
		(a)	(b)	(c)	(d)	(e)	(f)
1	Purchased Exp.	24,333			24,333		[1]
2							
3	Admin. & General	332,431		332,431			[2]
4							
5	Depre. & Amortization	378	0	183	195	0	[3][2]
6							
7	Property & Other Taxes	1,145	0	554	591	0	[3][5]
8							
9	Return	32,183	0	15,577	16,606	0	[3][6]
10							
11	Income Taxes	13,467	0	6,518	6,949	0	[3][4]
12							
13							
14	Revenue Requirement	403,937	0	355,263	48,674	0	

Notes
[1] Total From Sheet 4
[2] Allocated To Functions On Sheet 1
[3] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[4] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1
[5] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[6] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of GAS COSTS to Classes of Service

Line No.	Item	Alloc. Factor	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Purchased Exp.	Vol·A	24,333	6,482	3,446	835	3,353	10,217
2								
3	Admin. & General	A&P/Gas	332,431	196,467	102,854	18,084	8,743	6,283
4								
5								
6	Depre. & Amortization	Rb·Dem	183	87	45	7	14	30
7		Rb·Com	195	68	35	7	22	63
8								
9	Property & Other Taxes	Rb·Dem	554	263	137	22	43	89
10		Rb·Com	591	207	105	21	66	192
11								
12	Return	Rb·Dem	15,577	7,397	3,860	623	1,198	2,499
13		Rb·Com	16,606	5,818	2,948	601	1,851	5,388
14								
15	Income Taxes	Rb·Dem	6,518	3,095	1,615	261	501	1,046
16		Rb·Com	6,949	2,435	1,233	251	774	2,256
17								
18								
19	Revenue Requirement		403,937	222,319	116,278	20,712	16,565	28,063

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
STORAGE - CLASSIFICATION

Line No.	Item	Total	Customer	Demand	Commodity	Direct	Notes
		(a)	(b)	(c)	(d)	(e)	(f)
1	Accts. 818 & 819	$72,474			$72,474		[1][3]
2							
3	All Other Accounts	242,575		121,288	121,287		[2][3]
4							
5	Lp Expenses	2		2			[3]
6							
7	Admin. & General	149,008		74,504	74,504		[2][5]
8							
9	Depre. & Amortization	217,604	0	108,802	108,802	0	[4][5]
10							
11	Property & Other Taxes	51,917	0	25,959	25,958	0	[4][6]
12							
13	Return	1,237,781	0	618,891	618,890	0	[4][7]
14							
15	Income Taxes	516,405	0	258,203	258,202	0	[4][8]
16							
17							
18	Revenue Requirement	2,487,766	0	1,207,649	1,280,117	0	

Notes [1] Compressor Station Expense Fuel Accounts, 100 % Commodity
[2] 50 % Demand, 50% Commodity
[3] Total From Sheet 4
[4] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[5] Allocated To Functions On Sheet 1
[6] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[7] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3
[8] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of STORAGE COSTS to Classes of Service

Line No.	Item	Alloc. Factor	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Accts. 818 & 819	Winter	$72,474	$24,975	$12,625	$2,566	$8,175	$24,133
2								
3	All Other Accounts	Design-B	121,288	74,580	38,873	6,113	643	1,079
4		Winter	121,287	41,796	21,128	4,294	13,681	40,388
5								
6	Lp Expenses	Design-B	2	1	1	0	0	0
7								
8	Admin. & General	Design-B	74,504	45,813	23,879	3,755	395	662
9		Winter	74,504	25,674	12,979	2,637	8,404	24,810
10								
11	Depr. & Amortization	Rb-Dem	108,802	51,665	26,958	4,348	8,368	17,463
12		Rb-Com	108,802	38,122	19,313	3,935	12,125	35,307
13								
14	Property & Other Taxes	Rb-Dem	25,959	12,327	6,432	1,037	1,997	4,166
15		Rb-Com	25,958	9,095	4,608	939	2,893	8,424
16								
17	Return	Rb-Dem	618,891	293,880	153,344	24,735	47,602	99,330
18		Rb-Com	618,890	216,844	109,856	22,384	68,971	200,835
19								
20	Income Taxes	Rb-Dem	258,203	122,608	63,976	10,320	19,860	41,439
21		Rb-Com	258,202	90,468	45,832	9,339	28,775	83,788
22								
23								
24	Revenue Requirement		2,487,766	1,047,848	539,804	96,402	221,889	581,824

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
DISTRIBUTION - CLASSIFICATION

Line No.	Item	Total	Customer	Demand	Commodity	Direct	Notes
		(a)	(b)	(c)	(d)	(e)	(f)
1	Accts. 876 & 890	$290,520				$290,520	[1][5]
2	98% Of Accts. 901 - 910	5,789,626	5,789,626				[2][5]
3	64% of Accts. 911 - 916	52,154			52,154		[3][5]
4	Admin. & General	6,882,115	2,294,038	2,294,038	2,294,039		[4][8]
5	98% Of Accts. 878,879, 880,892,893,894	2,292,526	2,292,526				[5]
6	Other Accts. 870 Through 894	6,126,196	3,203,796	1,522,155	1,400,244		[6][5]
7	Depre. & Amortization	5,624,201	2,902,650	1,358,807	1,246,885	115,859	[7][8]
8	Property & Other Taxes	1,571,067	810,827	379,570	348,306	32,364	[7][9]
9	Return	9,727,986	5,020,614	2,350,281	2,156,694	200,397	[7][10]
10	Income Taxes	4,060,280	2,095,510	980,964	900,164	83,642	[7][11]
11	Revenue Requirement	42,416,671	24,409,588	8,885,815	8,398,486	722,782	

Notes
[1] O/M - Meas. And Reg. Station Accounts - Industrial, Direct Assigned
[2] Customer Accounts Expenses, 100 % Customer
[3] Sales Expenses Accounts, 100 % Commodity
[4] 1/3 To Each: Customer, Demand, Commodity
[5] Total From Sheet 4
[6] Used Plant Allocator, Sheet 4
[7] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[8] Allocated To Functions On Sheet 1
[9] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[10] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3
[11] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of DISTRIBUTION COSTS to Classes of Service

Line No.	Item	Alloc. Factor	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Accts. 876 & 890 Direct	Cust-E	$290,520	$0	$0	$3,661	$158,682	$128,177
2								
3	98% Of Accts. 901 - 910	Cust-B	5,789,626	3,813,627	1,882,208	56,738	31,843	5,210
4								
5	64% Of Accts. 911 - 916	Vol-A	52,154	13,894	7,385	1,789	7,187	21,899
6								
7	Admin. & General	Cust-A	2,294,038	2,037,565	251,427	2,982	1,835	229
8		Vol-A	2,294,039	611,132	324,836	78,686	316,119	963,266
9		Design-A	2,294,038	927,938	483,813	76,162	274,367	531,758
10								
11	98% Of Accts 878,879,							
12	880,892,893,894	Cust-B	2,292,526	1,510,087	745,300	22,467	12,609	2,063
13								
14	Other Accts 870 Through	Cust-B	3,203,796	2,110,341	1,041,554	31,397	17,621	2,883
15	894	Design-A	1,522,155	615,712	321,023	50,536	182,050	352,834
		Rb-Com	1,400,244	490,611	248,551	50,644	156,048	454,389
16								
17	Depre. & Amortization	Rb-Cus	2,902,650	1,639,516	720,376	42,047	130,718	369,993
18		Rb-Dem	1,358,807	645,230	336,675	54,307	104,512	218,083
19		Rb-Dir	115,859	0	0	1,460	63,282	51,117
		Rb-Com	1,246,885	436,878	221,329	45,098	138,958	404,623
20								
21	Property & Other Taxes	Rb-Cus	810,827	457,983	201,230	11,745	36,515	103,354
22		Rb-Dem	379,570	180,239	94,047	15,170	29,195	60,919
23		Rb-Dir	32,364	0	0	408	17,677	14,279
		Rb-Com	348,306	122,038	61,826	12,598	38,817	113,028
24								
25	Return	Rb-Cus	5,020,614	2,835,814	1,246,010	72,727	226,099	639,964
26		Rb-Dem	2,350,281	1,116,031	582,335	93,933	180,772	377,210
27		Rb-Dir	200,397	0	0	2,525	109,457	88,415
		Rb-Com	2,156,694	755,652	382,825	78,004	240,350	699,862
28								
29	Income Taxes	Rb-Cus	2,095,510	1,183,615	520,061	30,355	94,369	267,110
30		Rb-Dem	980,964	465,811	243,056	39,206	75,451	157,440
31		Rb-Dir	83,642	0	0	1,054	45,685	36,903
		Rb-Com	900,164	315,395	159,784	32,557	100,318	292,110
32								
33								
34	Revenue Requirement		42,416,671	22,285,109	10,075,651	908,256	2,790,536	6,357,119

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
TRANSMISSION - CLASSIFICATION

Line No.	Item	Total (a)	Customer (b)	Demand (c)	Commodity (d)	Direct (e)	Notes (f)	Check
1	Accts. 850 - 867	$392,071		$392,071			[1]	$392,071
2								
3	2% Of Accts. 878,879,							
4	880,892,893,894	46,786	46,786				[1]	46,786
5								
6	Admin. & General	277,322		277,322			[4]	277,322
7								
8	36% Of Accts. 911 - 916	29,336			29,336		[1]	29,336
9								
10	2% Of Accts. 901 - 910	118,156	118,156				[1]	118,156
11								
12	Depre. & Amortization	641,822	0	641,822	0	0	[2][3]	641,822
13								
14	Property & Other Taxes	276,001	0	276,001	0	0	[2][4]	276,001
15								
16	Return	1,398,054	0	1,398,054	0	0	[2][5]	1,398,054
17								
18	Income Taxes	583,740	0	583,740	0	0	[2][6]	583,740
19								
20								
21	Revenue Requirement	3,763,288	164,942	3,569,010	29,336	0		3,763,288

Notes
[1] Total From Sheet 4
[2] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[3] Allocated To Functions On Sheet 1
[4] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[5] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3
[6] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of TRANSMISSION COSTS to Classes of Service

Line No.	Item	Alloc. Factor	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Accts 850-865	A&P	$392,071	$207,523	$108,447	$18,231	$14,820	$43,050
2								
3	2% Of Accts 878,879,							
4	880,892,893,894	Cust-B	46,786	30,818	15,210	459	257	42
5								
6	Admin. & General	A&P	277,322	146,787	76,707	12,895	10,483	30,450
7								
8	36% Of Accts. 911 - 916	Vol-A	29,336	7,815	4,154	1,006	4,043	12,318
9								
10	2% Of Accts. 901 - 910	Cust-B	118,156	77,829	38,412	1,158	650	107
11								
12	Depre. & Amortization	Rb-Dem	641,822	304,769	159,026	25,652	49,366	103,010
13								
14	Property & Other Taxes	Rb-Dem	276,001	131,059	68,385	11,031	21,229	44,297
15								
16	Return	Rb-Dem	1,398,054	663,866	346,399	55,876	107,531	224,382
17								
18	Income Taxes	Rb-Dem	583,740	277,189	144,635	23,330	44,898	93,688
19								
20								
21	Revenue Requirement		3,763,288	1,847,655	961,375	149,637	253,277	551,343

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
PRODUCTION - CLASSIFICATION

Line No.	Item	Total	Customer	Demand	Commodity	Direct	Notes
		(a)	(b)	(c)	(d)	(e)	(f)
1	Accts 750-798	$2,854		$2,854			[1]
2							
3	Admin. & General	1,350		$1,350			[3]
4							
5	Depre. & Amortization	2,834	0	2,834	0	0	[2][3]
6							
7	Property & Other Taxes	8,590	0	8,590	0	0	[2][4]
8							
9	Return	13,481	0	13,481	0	0	[2][5]
10							
11	Income Taxes	5,697	0	5,697	0	0	[2][6]
12							
13							
14	Revenue Requirement	34,806	0	34,806	0	0	

NOTES
[1] Total From Sheet 4
[2] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[3] Allocated To Functions On Sheet 1
[4] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[5] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3
[6] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of PRODUCTION COSTS to Classes of Service

Line No.	Item	Alloc. Factor	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Accts 750-798	A&P	$2,854	$1,511	$789	$133	$108	$313
2								
3	Admin. & General	A&P	1,350	715	373	63	51	148
4								
5	Depre. & Amortization	Rb-Dem	2,834	1,346	702	113	218	455
6								
7	Property & Other Taxes	Rb-Dem	8,590	4,079	2,128	343	661	1,379
8								
9	Return	Rb-Dem	13,481	6,401	3,340	539	1,037	2,164
10								
11	Income Taxes	Rb-Dem	5,697	2,705	1,412	228	438	914
12								
13								
14	Revenue Requirement		34,806	16,757	8,744	1,419	2,513	5,373

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Derivation of COST ALLOCATORS at Normalized Volumes

Line No.	Item	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.	Cost Allocator
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Annual Volume-Mcf							
2	Total	50,014,309	13,324,639	7,083,095	1,712,796	6,893,542	21,000,237	
3		1.0000	0.2664	0.1416	0.0343	0.1378	0.4199	Vol-A
4	Regular Sales	23,558,414	13,324,639	7,083,095	1,526,449	1,435,663	188,568	
5		1.0000	0.5656	0.3007	0.0648	0.0609	0.0080	Sales
6	LVS Sales	629,986	0	0	2,931	328,819	298,236	
7		1.0000	0.0000	0.0000	0.0047	0.5219	0.4734	LVS
8	Total Sales	24,188,400	13,324,639	7,083,095	1,529,380	1,764,482	486,804	
9		1.0000	0.5509	0.2928	0.0632	0.0730	0.0201	TotSales
10	Sales & Stand-by [1]	25,732,793	13,324,639	7,083,095	1,712,796	2,336,335	1,275,928	
11		1.0000	0.5178	0.2752	0.0666	0.0908	0.0496	W/Gas
12								
13	Winter Period-Mcf [2]							
14	Total	28,532,291	9,831,002	4,971,215	1,009,350	3,220,127	9,500,597	
15		1.0000	0.3446	0.1742	0.0354	0.1128	0.3330	Winter
16								
17	Design Day-Mcf [3]							
18	G-1	287,219	176,618	92,063	14,477	1,519	2,542	
19	G-2/T-3/T-4	149,370				50,681	98,689	
20	Total	436,589	176,618	92,063	14,477	52,200	101,231	
21	Not Curtailed	1.0000	0.4045	0.2109	0.0332	0.1196	0.2318	Design-A
22	Curtailed	1.0000	0.6149	0.3205	0.0504	0.0053	0.0089	Design-B
23								
24	No. Of Customers							
25	12 Month Average	174,127	154,661	19,084	231	130	21	
26	Percent	1.0000	0.8882	0.1096	0.0013	0.0008	0.0001	Cust-A
27	Wt., R/C/I=1:4:10 [4]	1.0000	0.6587	0.3251	0.0098	0.0055	0.0009	Cust-B
28	Wt., 1:4:4:20:100	1.0000	0.6536	0.3226	0.0039	0.0110	0.0089	Cust-C
29								
30	Excl. Industrial	173,745	154,661	19,084				
31	Wt., 1:3.3	1.0000	0.7106	0.2894				Cust-D
32								
33	Large Customers [5]	154		0	3	130	21	
34	Weighted, 1:1:5	1.0000		0.0000	0.0126	0.5462	0.4412	Cust-E
35								
36	Meter Investment		154,661	19,084	231	130		
37	Wt., 1:3.3:21.4	1.0000	0.6863	0.2795	0.0219	0.0123		Cust-M
38								
39	Average & Peak [6]	1.0000	0.5293	0.2766	0.0465	0.0378	0.1098	A&P
40	Avg & Peak for Gas [7]	1.0000	0.5910	0.3094	0.0544	0.0263	0.0189	A&P/Gas
41	Load Factor [8]	0.2455						

Notes [1] Total sales volumes plus transportation volumes with sales stand-by rights
[2] November Through March
[3] Daily Contract Demands For Rate 1 Industrial, G-2 And Large G-2 Customers And Estimated Design Day Use For Other Customers
[4] Number of Customers are weighted: Residential/Commercial/Industrial = 1/4/10
[5] G-1 Customers With 240 Mcf Daily Contract Demand Plus G-2 & Large G-2 Customers
[6] Vol-A Times Load Factor Plus Design-B Times One Minus Load Factor
[7] W/Gas Times Load Factor Plus Design-B Times One Minus Load Factor
[8] Normalized Annual Sales & Standby Volumes Divided By Annualized Design Day System Requirements

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Derivation of COST ALLOCATORS from Rate Base

Line No.	Cost Component	Cost Allocator	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer		$71,989,408	$40,662,070	$17,866,251	$1,042,810	$3,241,976	$9,176,300
2		Rb-Cus	1.00000	0.56483	0.24818	0.01449	0.04503	0.12747
3								
4	Demand		44,095,125	20,938,575	10,925,564	1,762,338	3,391,571	7,077,077
5		Rb-Dem	1.00000	0.47485	0.24777	0.03997	0.07691	0.16050
6								
7	Commodity		6,374,096	2,233,326	1,131,438	230,540	710,353	2,068,439
8		Rb-Com	1.00000	0.35038	0.17751	0.03617	0.11144	0.32451
9								
10	Direct		2,009,995	0	0	25,326	1,097,859	886,810
11		Rb-Dir	1.00000	0.00000	0.00000	0.01260	0.54620	0.44120
12								
13								
14	TOTAL		124,468,624	63,833,971	29,923,254	3,061,015	8,441,759	19,208,626
15								
16		Rb-Total	1.00000	0.51285	0.24041	0.02459	0.06782	0.15433

WESTERN KENTUCKY GAS COMPANY
BILL FREQUENCY ANALYSIS
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		RESIDENTIAL				FIRM COMMERCIAL				FIRM INDUSTRIAL			
		Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue
1	FIRM BILLS	1,855,928		$5.10	$9,465,233	229,012		$13.60	$3,114,563	2,770		$13.60	$37,672
2	Transport. Bills	0				0		45.00		108		45.00	4,860
	ParkingFees												178
3	Sales: 1-300		13,324,639	1.0615	14,144,104		5,819,317	1.0615	6,177,205		443,296	1.0615	470,559
4	Sales: 301-15000		0	0.5585	0		1,263,778	0.5585	705,820		1,083,153	0.5585	604,941
5	Trans: 1-300						0	1.0615	0		17,016	1.0615	18,062
6	Trans: 301-15000						0	0.5585	0		166,400	0.5585	92,934
7	LVS: 1-300							1.0615			372	1.0615	395
8	LVS: 301-15000							0.5585			2,559	0.5585	1,429
9													
10	Total		13,324,639		$23,609,337		7,083,095		$9,997,588		1,712,796		$1,231,030
11													
12						INTERRUPTIBLE CUSTOMERS				LARGE INTERRUPTIBLE CUSTOMERS			
13						Number Of			Total	Number Of			Total
14						Bills	Mcf	Rate	Revenue	Bills	Mcf	Rate	Revenue
15	Bills					1,555		$150.00	$233,250	251		$150.00	$37,650
16	Transport. Bills					1,121		$45.00	$50,445	239		$45.00	$10,755
17	Parking Fees												52,474
18	Firm Sales: 1-300						36,188	1.0615	38,414		3,000	1.0615	3,185
19	Firm Sales: 301-15000						140,672	0.5585	78,565		12,028	0.5585	6,718
20	Firm Sales: Over 15000						2,108	0.4085	861		0	0.4085	0
21	Firm Trans: 1-300						8,939	1.0615	9,489		4,500	1.0615	4,777
22	Firm Trans: 301-15000						95,700	0.5585	53,448		238,829	0.5585	133,386
23	Firm Trans: Over 15000						0	0.4085	0		78,311	0.4085	31,990
24	Firm LVS: 1-300						2,700	1.0615	2,866		3,900	1.0615	4,140
25	Firm LVS: 301-15000						68,715	0.5585	38,377		13,815	0.5585	7,716
26	Firm LVS: Over 15000						6,711	0.4085	2,741		0	0.4085	0
27	T-4: 1-300						136,605	1.0615	145,006		32,100	1.0615	34,074
28	T-4: 301-15000						1,760,007	0.5585	982,964		919,996	0.5585	513,818
29	T-4: Over 15000						7,076	0.4085	2,891		524,473	0.4085	214,247
30	Interrupt Sales: 1-15000						982,994	0.4936	485,206		116,691	0.4936	57,599
31	Interrupt Sales: Over 15000						129,546	0.3436	44,512		22,939	0.3436	7,882
32	Interrupt Transport: 1-15000						459,426	0.4936	226,773		327,138	0.4936	161,475
33	Interrupt Transport: Over 15000						7,788	0.3436	2,676		140,346	0.3436	48,223
34	Interrupt LVS: 1-15000						145,693	0.4936	71,914		161,050	0.4936	79,494
35	Interrupt LVS: Over 15000						105,000	0.3436	36,078		119,471	0.3436	41,050
36	Carriage:1-15000						2,324,362	0.4936	1,147,305		1,852,647	0.4936	914,467
37	Carriage:Over 15000						26,074	0.3436	8,959		3,467,803	0.3436	1,191,537
38	T-4 Overrun 0-300						11,639	1.1677	13,591		0	1.1677	0
39	T-4 Overrun 301-15000						23,390	0.6144	14,371		2,020	0.6144	1,241
40	T-3 Overrun 0-15000						109,126	0.5430	59,255		31,890	0.5430	17,316
41	Special Contracts						303,083	various	71,976		12,927,290	various	1,855,349
42													
43	CLASS TOTAL						6,893,542		$3,821,933		21,000,237		$5,430,563
44													
45	GRAND TOTAL										50,014,309		$44,090,451

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Monthly Customer Cost

Line No.	Customer Cost	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)
1	O &M Expense	$14,035,448	$9,580,267	$3,974,111	$118,862	$223,497	$138,711
2							
3	Depreciation & Amortization	3,018,509	1,639,516	720,376	43,507	194,000	421,110
4							
5	Property & Other Taxes	843,191	457,983	201,230	12,153	54,192	117,633
6							
7	Income Taxes	2,179,152	1,183,615	520,061	31,409	140,054	304,013
8							
9	Return	5,221,011	2,835,814	1,246,010	75,252	335,556	728,379
10							
11							
12	Total	25,297,311	15,697,195	6,661,788	281,183	947,299	1,709,846
13							
14							
15	Number Of Customers	174,127	154,661	19,084	231	130	21
16							
17	Customer Cost Per Customer						
18	Per Month	$12.11	$8.46	$29.09	$101.44	$607.24	$6,785.10

WESTERN KENTUCKY GAS COMPANY
FUNCTIONAL ALLOCATIONS

Line No.		Total (a)	Gas Cost (b)	Storage (c)	Distribution (d)	Transmission (e)	Production (f)	Sub Total (g)	Intangible (h)	General Plant (i)	Div 02 Gross Plant (j)
	RATE BASE ITEMS										
1	Gas Plant [1]	203,141,249	100,000	4,884,111	147,989,309	25,999,146	830,133	179,802,699	128,182	16,646,897	6,563,471
2	Gross Plant Pct. (Grsplt%)		0.06%	2.72%	82.31%	14.46%	0.45%	100.00%			
3	Other Alloc By Grsplt%		14,003	634,809	19,209,960	3,374,754	105,024	23,338,550			
4	With Alloc By Grsplt%	203,141,249	114,003	5,518,920	167,199,269	29,373,900	935,157	203,141,249			
5	In Progress	2,196,907	1,318	59,756	1,808,274	317,673	9,886	2,196,907			
6	With Alloc By Grsplt%	17,179,026	10,307	467,270	14,140,056	2,484,087	77,306	17,179,026			14,982,119
7	Reserve For Depreciation	94,938,460	0	3,457,534	64,735,565	14,675,910	783,411	83,652,420	119,853	8,242,541	2,923,646
8	With Alloc By Grsplt%	94,938,460	6,772	3,764,514	74,025,104	16,307,871	834,198	94,938,460			
9											
10	Net Rate Base	124,468,251	322,801	12,415,055	97,572,577	14,022,604	135,214				
11	Rate Base Percentage	100.00%	0.26%	9.97%	78.39%	11.27%	0.11%				
11	EXPENSES										
12	Deprec. & Amort. Expense	6,486,839	0	200,474	5,105,830	550,756	0	5,857,060	0	629,779	
13	With Alloc By Grsplt%	6,486,839	378	217,604	5,624,201	641,822	2,834	6,486,839		0	
14	Admin.& General Expense [2]	7,642,226	332,431	149,008	6,882,115	277,322	1,350				
15	Other Non-Gas O&M	15,479,609	24,333	315,051	14,551,022	586,349	2,854				
16	Operation & Maintenance	23,121,835	356,764	464,059	21,433,137	863,671	4,204				
17	O&M Percentage	100.00%	1.54%	2.01%	92.69%	3.74%	0.02%				

[1] Excluding Acquisition Adjustment, moved $3,189,471 of additions to 6 and 8 inch mains from distribution to transmission

[2] Administrative And General Expenses Allocated To Functions In Proportion To Other Non-Gas O&M Except That Gas Supply Department Expenses Are Allocated Directly To Gas Cost

Line No.		Category	Total (a)	Customer (b)	Demand (c)	Commodity (d)	Direct (e)
	ACCT.	DISTRIBUTION PLANT ACCOUNT					
1	374.10	Land- T.B.	58,433	13,229	45,204		
2	374.20	Land- Other	44,872	10,159	34,713		
3	374.30	Rights-Of-Way	2,784	630	2,154		
4	375.10	Structures & Impr.	106,376	24,084	82,292		
5	375.03	Improvements	7,518	1,702	5,816		
6	375.20	Land Rights	46,591	10,548	36,043		
7	376.00	Mains (adj. Per sheet 1)	65,628,322	0	32,814,161	32,814,161	
8	378.10	Meas. & Reg General	1,881,560	425,985	1,455,575		
9	379.30	Meas & Reg Other	1,650,884	373,760	1,277,124		
10	380.00	Services	42,501,668	42,501,668			
11	381.00	Meters	18,009,721	18,009,721			
12	381.20	Gauges	109,765				109,765
13	382.00	Meter Installations	10,938,730	10,938,730			
14	383.00	House Regulators Service	3,428,992	3,428,992			
15	383.20	House Regulators Relief	481,544	481,544			
16	384.00	House Reg. Installations	154,276	154,276			
17	385.00	Meas & Reg Indust.	2,937,272				2,937,272
18							
19							
20	TOTAL DISTRIBUTION PLANT		147,989,308	76,375,028	35,753,082	32,814,161	3,047,037
21		Percent Of Total	100.00%	51.61%	24.16%	22.17%	2.06%
22							
23	PERCENT OF TOTAL CLASSIFICATION IN ACCOUNTS:						
24							
25	376.00	Mains		0.00%	91.78%	100.00%	
26	380.00	Services		55.65%	0.00%		
27	381.00	Meters		23.58%	0.00%		
28		All Others		20.77%	8.22%		100.00%
29							
30		Total		100.00%	100.00%	100.00%	100.00%
31							
32							
33	RATE BASE - CLASSIFICATION PERCENTAGE						
34							
35		Gas Cost	100.00%	0.00%	48.40%	51.60%	0.00%
36		Storage	100.00%	0.00%	50.00%	50.00%	0.00%
37		Distribution	100.00%	51.61%	24.16%	22.17%	2.06%
38		Transmission	100.00%	0.00%	100.00%	0.00%	0.00%
39		Production	100.00%	0.00%	100.00%	0.00%	0.00%
40							
41		Total Rate Base	100.00%	40.46%	35.43%	22.50%	1.61%

WESTERN KENTUCKY GAS COMPANY
12 MONTH AVERAGES

Sum of Ending Balance	Month						
Account	October-97	November-97	December-97	January-98	February-98	March-98	April-98
1540 Cur Asset-Plnt Matls & Op	1,030,998.16	1,004,680.71	912,053.72	856,270.93	961,167.10	922,488.23	806,611.13
1550 Current Assets-Merchandis	22,723.44	21,230.17	21,813.88	20,757.12	20,643.51	19,234.44	17,074.27
1630 Cur Asset-Stores Expense	446,663.48	453,178.21	422,761.79	421,714.19	410,284.83	409,081.80	388,664.37
1640 Cur Asset-U/G Stored Gas	11,776,167.85	13,232,086.28	12,937,192.86	10,002,571.05	7,921,546.78	5,671,434.03	3,568,139.93
1660 Cur Asset-Prepayments	1,589,760.84	625,862.16	607,162.36	594,752.65	556,270.82	538,953.24	475,813.08
within 166 prepaid gas all.	1,172,398.13	82,643.27	82,643.27	82,643.27	82,643.27	82,643.27	82,643.27

	May-98	June-98	July-98	August-98	September-98	Grand Total	Average
1540 Cur Asset-Plnt Matls & Op	845,724.40	875,035.97	836,239.81	818,908.08	784,493.39	10,654,671.63	887,889.30
1550 Current Assets-Merchandis	16,266.93	15,275.01	15,160.36	13,458.85	13,072.94	216,710.92	18,059.24
1630 Cur Asset-Stores Expense	400,293.09	419,922.52	432,573.00	434,889.62	451,226.71	5,091,253.61	424,271.13
1640 Cur Asset-U/G Stored Gas	5,691,691.84	5,691,236.36	7,199,700.77	9,414,382.47	11,343,705.04	104,449,855.26	8,704,154.61
1660 Cur Asset-Prepayments	440,996.96	427,618.52	566,568.99	522,256.14	216,366.92	7,162,382.68	596,865.22
within 166 prepaid gas all.	82,643.27	82,643.27	82,643.27	82,643.27	0	1,998,830.83	166,569.24

within 166 prepaid gas	October-97	November-97	December-97	January-98	February-98	March-98	April-98
tenn alliance	617,824.98	192,804.34	192,804.34	192,804.34	192,804.34	192,804.34	192,804.34

WESTERN KENTUCKY GAS COMPANY
MISCELLANEOUS INPUTS

line no.	O&M To Functions - Detail	Per Books (a)	Adjustments (b)	Total (c)
1	Gas Cost: 807	24,333		24,333
2	Lp: 717 Through 742	2		2
3	Production: 750 Through 798	2,854		2,854
4	Storage: 818 & 819	72,474		72,474
5	Storage: Other Accounts	242,575		242,575
6	Transmission	392,071		392,071
7	Distribution: 878,879,880,892,893,894	2,339,312		2,339,312
8	Distribution: 876 & 890	290,520		290,520
9	Distribution: Other Accounts	6,126,196		6,126,196
10	Customer Accts & Services: 901 - 910	4,975,189	932,593	5,907,782
11	Sales Expenses: 911 - 916	81,490		81,490
12	A&G Expenses	7,642,226		7,642,226
13				
14	Total Non-Gas O&M And A&G	22,189,242		23,121,835
15				
16				
17				
18	Plant Allocator (From Sheet 7)			
19	Demand	0.7736		
20	Customer	0.2264		
21				
22	Interest Expense	4,754,687		
23				
24	Combined Income Tax Rate	0.403625		
25	Income Taxes	5,179,589		
26				
27	Property & Other Taxes	1,908,720		
28				
29				
30	Proposed after tax return on Rate Base			
31	Equity return	6.15%		
32	Debt return	3.82%		
33	Proposed Rate Of Return On Rate Base	9.97%		
34				
35				
36	Pretax return on Rate Base			
37	Equity return	10.31%		
38	Debt return	3.82%		
39	Total return	14.13%		
40				
41	General Office Allocation Percent	16.66%		

WESTERN KENTUCKY GAS COMPANY
TOTALS FROM PAGES 6 THROUGH 15 OF STUDY

Line No.	Classification	(a) Total	(b) Customer	(c) Monthly Demand	(d) Commodity	(e) Direct	(f) Check
1	O & M	23,121,835	13,744,928	5,018,015	4,068,371	290,520	23,121,835
2	Depreciation & Amort	6,486,839	2,902,650	2,112,448	1,355,882	115,859	6,486,839
3	Property & Other Taxes	1,908,720	810,827	690,674	374,855	32,364	1,908,720
4	Return	12,409,485	5,020,614	4,396,284	2,792,190	200,397	12,409,485
5	Income Taxes	5,179,589	2,095,510	1,835,122	1,165,315	83,642	5,179,589
6	Revenue Requirement	49,106,468	24,574,529	14,052,543	9,756,613	722,782	49,106,468
7							
8							
9							
10							
11							
12			Firm	Firm	Firm	Interr. &	Large
13	Allocation To Classes	Total	Residential	Commercial	Industrial	Carriage	Int. & Carr.
14							
15	O & M	23,121,835	13,019,693	5,765,974	447,291	1,232,167	2,656,709
16	Depreciation & Amort	6,486,839	3,117,681	1,484,459	176,974	507,583	1,200,144
17	Property & Other Taxes	1,908,720	917,290	438,898	53,314	149,093	350,127
18	Return	12,409,485	5,901,704	2,830,918	351,946	984,868	2,340,048
19	Income Taxes	5,179,589	2,463,321	1,181,604	146,900	411,070	976,694
20	Revenue Requirement	49,106,468	25,419,689	11,701,852	1,176,425	3,284,780	7,523,721

WESTERN KENTUCKY GAS COMPANY
REVENUE AT PRESENT AND PROPOSED RATES

Line No.	Cost Item	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)
1							
2	Revenue:						
3							
4	Gas Operating Margins	$44,090,451	$23,609,337	$9,997,588	$1,231,030	$3,821,933	$5,430,563
5							
6	EFM Revenue	77,805	0	0	2,310	57,750	17,745
7							
8	Other Revenue	674,727	599,293	73,950	877	540	67
9							
10	Total Operating Margins	44,842,983	24,208,630	10,071,538	1,234,217	3,880,223	5,448,375

WESTERN KENTUCKY GAS COMPANY
DISTRIBUTION MAINS STUDY
Test Year Ended September 30, 1998

Line No.	(1) Size	(2) X	(3) W Feet	(4) W*X	(5) W*Y $	(6) Y $ Per Foot	(7) X-avgX	(8) W(X-avgX)	(9) Y-avgY	(10) W(Y-avgY)	(11) (8)*(9)	(12) (8)*(7) (I)
1	<2"	1	784,916	784,916	1,734,239	2.2095	(4.67)	(3,662,941)	(1.73)	(1,356,127)	6,328,592	17,093,726
2	2"	2	10,528,812	21,057,624	32,944,091	3.1289	(3.67)	(38,605,644)	(0.81)	(8,509,876)	31,202,879	141,554,028
3	3"	3	431,511	1,294,533	850,463	1.9709	(2.67)	(1,150,696)	(1.97)	(848,479)	2,262,611	3,068,523
4	4"	4	3,373,749	13,494,996	21,648,330	6.4167	(1.67)	(5,622,915)	2.48	8,365,228	(13,942,047)	9,371,525
5	5"	5	6,015	30,075	6,396	1.0633	(0.67)	(4,010)	(2.87)	(17,286)	11,524	2,673
6	6"	6	661,535	3,969,210	4,542,356	6.8664	0.33	220,512	2.93	1,937,765	645,922	73,504
7	8"	8	96,603	772,824	778,745	8.0613	2.33	225,407	4.12	398,400	929,601	525,950
8	10"	10	12,265	122,650	78,531	6.4029	4.33	53,148	2.47	30,241	131,046	230,309
9	12"	12	6	72	157	26.1667	6.33	38	22.23	133	845	241
10												
11	Total	51.00	15,895,412	41,526,900	62,583,308		0.00	(48,547,101)	26.85	0	27,570,972	171,920,479
12												
13	Average	5.67				3.9372						
14												
15												

Line No.	(13) Size	(14) Ycalc A+B*X	(15) Y-Ycalc	(16) W*(15)^2	(17) W*(9)^2
19					
20	<2"	2.06	0.15	18,163	2,343,028
21	2"	3.22	(0.09)	93,405	6,878,078
22	3"	4.39	(2.42)	2,522,995	1,668,363
23	4"	5.55	0.86	2,506,706	20,741,628
24	5"	6.72	(5.66)	192,502	49,678
25	6"	7.89	(1.02)	688,155	5,676,091
26	8"	10.22	(2.16)	449,295	1,643,042
27	10"	12.55	(6.15)	463,385	74,565
28	12"	14.88	11.29	764	2,965
29					
30	Total	67.48	(5.19)	6,935,370	39,077,438
31					
32	TOT. >2"		4,581,684	$27,904,978	6.0906
33	@ 2" PRICE		4,581,684	$14,335,845	3.1289
34	Difference		4,581,684	$13,569,133	2.9616
35					
36	0-Intercept		15,895,412	$14,171,506	0.8915

(18)
Calculated From
Column Totals

Y = A + B*X
B = [(3)*(11)-(9)*(8)]/[(3)*(12)-(8)^2]
A = (5)/(3)-B*[(4)/(3)]
R^2 = 1-[(16)/(17)*[9-1]/[9-2]

B = 1.1658

A = 0.8915

R^2 = 0.7972

	Minimum System	
Demand	$13,569,133	21.68%
Customer	$49,014,175	78.32%
	Regression Minimum	
Demand	$48,411,802	77.36%
Customer	$14,171,506	22.64%

WESTERN KENTUCKY GAS COMPANY
METER ANALYSIS
September 1998

Line No.	Meters	Type	Number	Investment	Invest/Meter
	(a)	(b)	(c)	(d)	(e)
1	Group A	Meters with Capacity of 250			
2		CFH or Less (Class 1)	178,703	$12,771,575.58	$71.47
3					
4	Group B	Meters with Capacity of Greater			
5		Than 250 CFH and Less Than or			
6		Equal to 450 CFH (Class 2)	5,412	$783,564.00	$144.78
7					
8	Group C	Meters with Capacity of			
9		Greater Than 450 CFH			
10		(Class 3)	1,335	$972,082.36	$728.15
11		(Class 4)	682	$627,292.63	$919.78
12		(Class 5)	483	$284,647.21	$589.33
13		(Class 6)	356	$389,827.03	$1,095.02
14		(Class 7)	287	$163,227.72	$568.74
15		(Class 8)	195	$264,219.70	$1,354.97
16		(Class 9)	733	$1,119,758.42	$1,527.64
17					
18		(Classes 3 - 9)	4,071	$3,821,055.07	$938.60
19					
20	Total		188,186	$17,376,194.65	$92.34
21					
22					
23					
24					
25	Number of Customers:				
26					
27		Residential			154,661
28		Commercial			19,084
29		Industrial & Interr. < 1,000 Contract Demand			352
30		Sub-total			174,097
31		Industrial & Interr. > 1,000 Contract Demand			30
32					
33		Total			174,127

34
35
36
37
38 Assumptions
39
40 1. All Residential Meters are in Group A
41 2. All Industrial Meters are in Group C
42 3. The average value for Industrial Meters is based on Class 9 Meters
43 4. Commercial Meters fall into all three Groups
44 5. Customers with Daily Contract Demands in excess of 1,000 do not have
45 meter investment in Account 381
46 6. Meters in Inventory are in proportion to Meters in use

^WESTERN KENTUCKY GAS COMPANY
METER ANALYSIS
September 1994

Analysis:	(a)	(b)	(c)	(d)
Meters		188,186		
Net Customers		174,097		
Ratio of Meters to Customers		108.09%		

Meter Allocation:

	Total	Residential	Commercial	Indus/Inter.
Net Customers	174,097	154,661	19,084	352
Meters				
Group A	178,703	167,173	11,530	
Group B	5,412		5,412	
Group C	4,071		3,691	380
Total	188,186	167,173	20,633	380

Meters - Gross Plant Value:

	Total Meters	Total Investment	Invest. Per Meter
Group A	178,703	$12,771,575.58	$71.47
Group B	5,412	$783,564.00	$144.78
Group C -Comm.	3,691	$3,240,551.87	$877.96
Group C -Ind./Inter.	380	$580,503.20	$1,527.64
Total	188,186	$17,376,194.65	$92.34

Gross Plant Value Allocation:

	Total	Residential	Commercial	Industrial
Group A	$12,771,903.41	$11,947,854.31	$824,049.10	
Group B	$783,549.36		$783,549.36	
Group C -Comm.	$3,240,550.36		$3,240,550.36	
Group C -Ind./Inter.	$580,503.20			$580,503.20
Total	$17,376,506.33	$11,947,854.31	$4,848,148.82	$580,503.20
Meters	188,186	167,173	20,633	380
Investment/Meter		$71.47	$234.97	$1,527.64
Relative Investment		1.0	3.3	21.4

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE TO
WESTERN KENTUCKY GAS CO. DATA REQUESTS
SET I

19. Reference pages 25-26, lines 26-2 [sic] of Galligan's testimony. Does Mr. Galligan suggest that a sharing ratio other than 90%:10% would more effectively provide an incentive to the Company to maximize its flexible rates? Explain.

Response

Any ratio higher than 10/100 would increase incentives to maximize flexible rate revenue. For example, the current 100/100 ratio (no recovery of discounted rate revenue between rate cases) provides a greater incentive than Western's proposed 10/100 (90 percent recovery) ratio.

Responsible Witness: Richard A. Galligan

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE TO
WESTERN KENTUCKY GAS CO. DATA REQUESTS
SET I

20. Reference page 27, lines 5-10. Does Mr. Galligan agree that in addition to costs associated with facilities required by the Commission's customer extension rules the return on the investment or margin generated by the extension would also impact the economics of the extension?

Response

The term "impact the economics" is not uniquely defined. Mr. Galligan agrees that costs and revenues are part of a rational investment analysis.

Responsible Witness: Richard A. Galligan

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE TO
WESTERN KENTUCKY GAS CO. DATA REQUESTS
SET I

21. Provide copies of testimony filed by Mr. Estomin in rate proceedings for the last two years.

Response

Attached are: (1) Dr. Estomin's Direct Testimony in Case No. 99-176 (Delta Gas Company) before the Kentucky PSC, and (2) Dr. Estomin's Direct and Surrebuttal Testimonies in Docket No. 96-116 (Bangor Hydro Electric Company) before the Maine PUC. Testimony in Docket No. 97-580 (Central Maine Power Company) before the Maine PUC was presented live and as a consequence no prefiled document exists. Transcripts for that proceeding are not available.

Responsible Witness: Steven L. Estomin

BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

RE: BANGOR HYDRO-ELECTRIC COMPANY PROPOSED INCREASE IN RATES	)))	DOCKET NO. 97-116

DIRECT TESTIMONY

OF

STEVEN L. ESTOMIN, PH.D.

ON BEHALF OF THE

MAINE PUBLIC UTILITIES COMMISSION STAFF

AUGUST 8, 1997

EXETER
Associates, Inc.
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

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BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

RE: BANGOR HYDRO-ELECTRIC COMPANY PROPOSED INCREASE IN RATES	)))	DOCKET NO. 97-116

DIRECT TESTIMONY OF STEVEN L. ESTOMIN

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven L. Estomin. By business address is Exeter Associates, Inc., 12510 Prosperity Drive, Suite 350, Silver Spring, Maryland, 20904. Exeter is an economics consulting firm specializing in public utility regulation, energy studies, and telecommunications.

Q. WHAT IS YOUR POSITION WITH EXETER ASSOCIATES, INC.?

A. I am a vice president and principal in the firm and my title is Senior Economist. My responsibilities include conducting and presenting economic and econometric analyses, performing econometric forecasting, and providing other professional services predominantly related to regulated industries.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND BACKGROUND.

A. I received a Bachelor of Arts degree with a major in economics in 1975, a Master of Arts degree in economics in 1978, and a Ph.D. in economics in 1986, all from the University of Maryland. My areas of specialization in graduate school were industrial organization, econometrics, and environmental economics.

I joined Exeter Associates, Inc. in 1981 as an economist and have been involved with economic analysis related to regulated industry since that time. A detailed statement of my qualifications is included as an appendix to this testimony.

Q. HAVE YOU TESTIFIED AS AN EXPERT WITNESS IN OTHER REGULATORY PROCEEDINGS?

A. Yes. I have testified before the utility commissions in Maryland, Vermont, New Mexico, New Jersey, Illinois, Rhode Island, and the District of Columbia on issues related to load forecasting, weather normalization, production planning, statistical analysis and other issues. I have also testified in U.S. District Court and before the Federal Energy Regulatory Commission on issues related to statistical estimation. In addition, I have previously testified before the Maine Public Utilities Commission on the issue of load forecasting in Docket Nos. 92-101 (Maine Public Service Company), 91-010 (Bangor Hydro-Electric Company), and 90-076 (Central Maine Power Company).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was requested by the Maine Public Utilities Commission Staff (Staff) to analyze Bangor Hydro-Electric Company's rate year sales forecast. In conducting this analysis, I made several modifications and adjustments to the Company's forecast and developed an alternative forecast to that prepared by the Company and used by Bangor Hydro-Electric to develop its revenue requirement filing.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. The Staff's projection of mWh sales for the 12 months ending February 1999 is approximately ___ percent higher than the projection relied upon by Bangor Hydro-Electric in its filing. A comparison between BHE's forecast and the Staff's forecast is shown in the table below.

Forecasted Sales For Year Ending February 1999 (Thousands of mWh)			
Class	BHE	Staff Division	Difference
Residential	537.2	565.2	28.0
Commercial	517.8	540.9	23.1
Industrial	167.0	174.2	7.2
Paper Mills	265.0	265.0	0.0
HoltraChem	227.8	227.8	0.0
Wholesale	4.5	4.5	0.0
Streetlighting	8.9	8.9	0.0
Total Sales	1,728.2	1,786.5	58.3
Total less HoltraChem and Paper Mills	1,235.4	1,293.7	58.3

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The next section of my testimony describes and critiques the overall approach used by BHE to develop its energy sales forecast and provides a summary of the forecast relied upon by the Company. Following that section are sections addressing the residential and commercial/ industrial forecasts. Those sections are followed by a brief section addressing forecasted sales to the remaining customer classes. The final section of my testimony contains a summary of the Staff's sales forecast, a detailed comparison with the Company's forecast, and a quantification of the impact of the alternative forecast on the Company's rate increase request.

Q. IS YOUR TESTIMONY ACCOMPANIED BY ANY SCHEDULES?

A. Yes. Schedules___(SLE-1) through (SLE-4) are attached. Schedule___(SLE-1) shows the underlying theory associated with the development of the residential and commercial/ industrial econometric sales equations that I relied upon to forecast sales to those customer classes. Schedules___(SLE-2) and (SLE-3) show the econometric equation estimations, and related information, for the residential and commercial/industrial classes, respectively. Schedule ___(SLE-4) shows forecasting assumptions relied upon to develop the residential and commercial/industrial sales projections.

Q. HOW DOES STAFF'S FORECAST OF RATE YEAR SALES COMPARE TO 1996 ACTUAL SALES LEVELS?

A. The table below shows actual 1996 sales, projected sales for 1997 (which include three months actual) and rate year sales. Also included in this table are the annual rates of growth by sales class.

BANGOR HYDRO-ELECTRIC COMPANY

Actual and Forecasted Sales (MWH), Growth Rate (%) from Prior Year

	1996[1]	1997[2]	Year Ending February 1999[3]
Residential	536,490	543,578	565,205
		+1.3	+3.4
Commercial	508,363	522,782	540,904
		+2.8	+3.0
Industrial	164,172	168,469	174,218
		2.6	+2.9
Paper Mills	260,042	264,928	265,000
		+1.9	0.0
HoltraChem	227,841	227,841	227,841
		0.0	0.0
Wholesale	4,468	4,500	4,500
		+0.7	0.0
Lighting	8,944	9,087	8,928
		+1.6	-1.5
Total	1,710,339	1,741,185	1,787,282
		+1.8	+2.3
Total Less HoltraChem and Paper Mills	1,222,456	1,248,416	1,294,441
		+2.1	+3.2

[1] Actual.
[2] Three months actual, nine months forecasted.
[3] Average annual growth rates from 1997.

II. OVERVIEW AND CRITIQUE OF BHE'S SALES FORECAST

Q. WHAT IS THE GENERAL METHOD USED BY BHE TO FORECAST RATE YEAR SALES?

A. In very general terms, the Company uses two broad approaches. One method, which can be described as a combination of econometric, time-trending, and engineering approaches, is used to project residential and commercial/industrial sales. The second method, used for all other categories of sales, is essentially judgmental whereby projections of sales for the rate year are based on recent historical levels of sales adjusted for known and anticipated changes. The categories of sales projected using the second approach are sales to paper mills, sales to HoltraChem, lighting sales and wholesale sales.

Q. IS THE LEVEL OF SECTORAL DISAGGREGATION EMPLOYED BY THE COMPANY APPROPRIATE?

A. In forecasting sales, it is useful to disaggregate sales to customer classes to permit the forecaster to capture important differences in the way that different customer groups respond to changes in the factors that affect sales levels. For example, industrial customers respond to changes in weather conditions differently than do residential customers. The company has separately addressed residential sales and grouped together commercial and industrial sales excluding paper mills and HoltraChem. Given the relatively small size of this sales category, approximately 13 percent of total sales in 1996, combining industrial sales with commercial sales for purposes of projecting rate year sales levels does not appear to be problematic.

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE METHOD BY WHICH BHE PROJECTED RESIDENTIAL SALES.

A. Residential sales were projected using a combination of econometric modeling, time trend analysis, and engineering estimates related to electricity used for electric space heating. To develop the forecast of residential sales, the following steps were employed:

Step 1: The Company econometrically estimated the relationship between residential sales per customer and weather conditions over the period from the first quarter of 1984 through the first quarter of 1997.

Step 2: Based on the econometric results, BHE estimated weather-normal per-customer sales for the historical period by inserting the 30-year average for heating degree days and 22-year average for cooling degree days into the estimated econometric equation.

Step 3: From the weather-normalized, historical quarterly per-customer sales estimates, the Company generated a four-quarter moving average series starting in the first quarter of 1989 and fit the series with a time trend line.

Step 4: The time-trend was extrapolated to generate projected, weather-normalized, 4-quarter moving average, per-customer sales.

Step 5: The projected figures generated in Step 4 were seasonalized by adjusting the quarterly moving average values by the average differences among calendar quarters.

Step 6: The figures obtained in Step 5 were adjusted to reflect differential growth among the calender quarters.

Step 7: The per-customer projections obtained in Step 6 were adjusted to subtract estimated energy use reductions (on a per-customer basis) resulting from Company-sponsored demand-side management programs.

Step 8: The per customer residential sales (projected) were multiplied by projections of the number of residential customers to obtain projected residential sales.

Step 9: The projected sales figures obtained in Step 8 were adjusted to reflect anticipated increases in electric space heating sales (1,160 mWh per year) and the attainment of electric water heater standards.

Q. IS THE METHOD BY WHICH THE COMPANY ECONOMETRICALLY ESTIMATED THE HISTORICAL RELATIONSHIP BETWEEN WEATHER AND PER CUSTOMER RESIDENTIAL SALES REASONABLE?

A. I have several serious problems with the econometric approach used by the Company to weather-normalize residential sales. Mr. Cooper, the Company's sales forecasting witness, explains in his direct testimony that the Company did not rely on an econometric approach to forecasting sales directly because Mr. Cooper was unable to produce satisfactory econometric results. (Direct Testimony of Roger D. Cooper, page 27, line 18, through page 29, line 14.) Mr. Cooper hypothesizes that the fundamental reason underlying the inadequacy of the econometric approach is an omitted variable in the equation. He then uses an econometric approach to weather-normalize per-customer residential sales. If the equation relied upon is not adequate to reasonably estimate the historical relationships for purposes of forecasting, there is no reason to expect that it is capable of reasonably estimating the relationship between weather and sales.

Q. DO YOU HAVE ANY SPECIFIC CONCERNS ABOUT THE ECONOMETRIC EQUATION THAT WAS RELIED ON BY THE COMPANY TO WEATHER-NORMALIZE PER-CUSTOMER RESIDENTIAL SALES?

A. Yes. My concerns relate to the structure of the residential sales equation and the manner in which consumer response to changes in income and price are represented.

The econometric equation used by BHE to weather-normalize sales is linear with the dependent variable specified as average monthly kWh sales during the calendar quarter (adjusted for DSM savings) divided by the average number of residential customers. The dependent variable is regressed on a constant term, an electricity price term, weather, and income. Price and income are specified in real, i.e., constant dollar, terms using the national all-items Consumer Price Index, or CPI. The price term is an eight-quarter moving average price. Consequently, the price term used in one quarter is composed of prices in effect for the current quarter and the prior seven calendar quarters.

The fundamental problem associated with this construction is that the model is unable to differentiate between short-term and long-term effects on usage. Residential consumers are unable to fully respond to changes in causal factors such as income or the price of electricity immediately. The reason for this is that electricity usage is dependent on the stock of electricity consuming appliances. Consumers can respond the changes in causal factors by modifying the intensity of use of the appliance stock and also by modifying the stock itself. Modification of the intensity of use of the appliance stock can occur quickly; modifications to the stock of appliances, such as purchasing a more energy-efficient appliance in response to an electricity price increase, occur only gradually as existing appliances wear out and require replacement.

The equation relied upon by BHE to weather-normalize residential sales does not allow for gradual adjustment to changes in the causal factors. All consumer response to a change in income is represented as occurring in the contemporaneous calendar quarter; consumer response to changes in price in the model is only marginally better. Because the electricity price variable is specified as an eight-quarter rolling average, the model will accommodate consumer response to changes in price over a two-year period. This specification remains problematic, however, because full consumer response to changes in the price of electricity occur over a longer time period than two years given the relatively long useful life of major electricity-consuming appliances such as water heaters, stoves, washers and dryers, and refrigerators. Furthermore, the consumer response to changes in price that occurred two years prior is identical to the consumer response to changes in price in the contemporaneous calendar quarter. This is not a reasonable reflection of the manner in which consumers respond to price changes. In particular, we would expect recent changes in price to have a greater impact on current usage than earlier changes in price.

Q. HOW DOES THIS PROBLEM AFFECT THE WEATHER VARIABLE?

A. As is the case with the other causal variables in the BHE residential equation, consumer response to changes in weather, i.e., heating and cooling degree days, is represented as instantaneous. This is a reasonable representation of the manner in which consumers respond to weather conditions. Because general weather conditions, that is, cold winters and warm summers, are fully anticipated, the stock of appliances reflects expectations regarding the general climate. Daily fluctuations in weather are responded to by changes in the intensity in the use of the stock of space conditioning equipment, which is a short-run effect. Consequently, it is appropriate that the weather variables be represented as having only short-run impacts, which is consistent with BHE's residential equation.

Q. SINCE THE PURPOSE OF THE EQUATION IS TO WEATHER NORMALIZE SALES, IS THE REASONABLENESS OF THE WEATHER VARIABLE SUFFICIENT TO ENSURE REASONABLE RESULTS?

A. No. The equation relied upon is misspecified due to the manner in which the price and income variables operate. Additionally, Mr. Cooper suggests that there are likely to be omitted variables. Both conditions result in biased estimates of the equation parameters, i.e., the estimated coefficients, on each of the equation regressors.

Q. IF THE RESIDENTIAL ECONOMETRIC EQUATION WERE APPROPRIATELY SPECIFIED TO YIELD UNBIASED RESULTS, WOULD THE REMAINDER OF THE METHODOLOGY USED BY BHE TO PROJECT RATE YEAR SALES BE APPROPRIATE?

A. If one assumes that the future will look like the past, then the time-trending approach used by the Company would represent a reasonable alternative to a more rigorous procedure. In particular, one needs to assume that not only will the responses of consumers to changes in the causal factors be the same in the future as in the past, one also needs to assume that the changes in the causal factors in the future will be like the changes in the causal factors in the past. Specifically, changes in real per capita personal income and changes in price will be similar to the changes in these variables that have occurred during the historical estimation period.

Q. IS THE ASSUMPTION THAT CHANGES IN THE CAUSAL VARIABLES IN THE FUTURE WILL BE SIMILAR TO CHANGES IN THE CAUSAL VARIABLES IN THE PAST APPROPRIATE?

A. No. We know, for example, that the Company has requested a rate increase which will affect sales during the rate year. Additionally, real per capita personal income is expected to increase at an average annual rate of about 2 percent over the next several years. This differs from the historical rate of 1.8 percent over the full estimation period relied upon by the Company (1984 through the first quarter of 1997).

Q. WHAT IS THE METHOD RELIED ON BY THE COMPANY TO FORECAST COMMERCIAL AND INDUSTRIAL SALES.

A. The Company employs a methodology similar to that employed for the residential sector, and the same problems exist for the same set of reasons. Specifically, the structure of the equation can accommodate only short-term effects and cannot accommodate gradual response to changes in long-run factors such as price. Consequently, the commercial equation is misspecified, as is the residential equation, and the results are biased, as are the results of the residential equation.

Q. ARE THERE ANY ADDITIONAL PROBLEMS THAT YOU HAVE IDENTIFIED WITH RESPECT TO THE METHOD EMPLOYED BY THE COMPANY TO PROJECT COMMERCIAL AND INDUSTRIAL SALES?

A. Yes. An adjustment is made to the projected sales figures to capture sales reductions due to the implementation of national energy efficiency standards applicable to lighting. For each calendar quarter in the forecast period, projected sales are reduced by approximately 0.7 percent (additive) to reflect the increasing saturation of higher-efficiency lighting as the existing stock of less energy-efficient lighting requires replacement. Full saturation is assumed to occur over a five-year period. It is noted that only fifty percent of the engineering estimate of reduced energy consumption associated with the implementation of the new efficiency standard is used for purposes of adjusting sales to implicitly recognize the fact that some customers have already installed the new energy-efficient lights and presumably to also take into account the expectation that less than the full engineering estimate of energy savings will materialize for a variety of reasons. Because weather-normalized sales are extrapolated from an econometric equation estimated over a historical period in which other efficiency standards have been implemented, which are in no way explicitly recognized through the formulation of the equation or dealt with through adjustment to the historical data itself, the adjustment for energy sales reductions associated with this one energy efficiency improvement may result in double counting potential savings.

Q. WHY MIGHT THE ENERGY SAVINGS BY DOUBLE COUNTED?

A. The econometric algorithm captures trends in the movement of the dependent variable determined by a variety of factors not explicitly recognized in the equation. For example, the increasing use of personal computers is not explicitly reflected in the regressors used to estimate either residential sales or commercial sales yet the effects of increasing personal computer use are captured through the estimated parameters on other regressors in the equation, such as price or income. This is one of the strong points of the econometric approach as compared to an engineering end-use approach; if the important factors affecting electricity use are correctly incorporated into the equation to be estimated, the effect of other less important, or unquantifiable, factors will also be captured. This relieves the forecaster from having to identify a virtually limitless array of influences affecting electricity consumption. Because other appliance efficiency standards have gone into effect since the 1980s, the degree to which the effect of new standards are already incorporated into the estimated parameters is unclear. What is clear, however, is that the effects of the implementation of energy efficiency standards are at least partially imbedded in the parameter estimates. To the extent that the forecasted sales levels are adjusted to account for one particular standard, the adjustment may result in the impact being accounted for twice: once through the estimated parameters and a second time through the ad hoc adjustment.

Q. YOU INDICATED THAT CERTAIN ENERGY EFFICIENCY STANDARDS HAVE PREVIOUSLY BEEN IMPLEMENTED THAT ARE NOT EXPLICITLY ACCOUNTED FOR BUT ARE REFLECTED TO AN INDETERMINATE DEGREE IN THE ESTIMATED PARAMETERS. COULD YOU PLEASE PROVIDE SOME EXAMPLES?

A. Yes. Numerous standards were established under the National Appliance Energy Conservation Act of 1987 and the Energy Policy Act of 1992. Standards for improved energy efficiency of clothes washers and dryers and dishwashers became effective in 1988; standards for air conditioners went into effect between 1990 and 1993, depending on the kind of air conditioner purchased; standards for heating equipment and for fluorescent lamp ballasts were implemented in 1990; other standards for air conditioning, fluorescent lamps, water heaters, furnaces and boilers became effective in 1994 and 1995.

Q. IS IT YOUR CONTENTION THAT THE IMPLEMENTATION OF THESE OTHER STANDARDS DURING THE HISTORICAL ESTIMATION PERIOD FULLY CAPTURE THE EFFECTS OF THE LIGHTING STANDARDS DURING THE FORECAST PERIOD?

A. No. My position is that embedded within the estimated parameters are the effects of increased appliance and equipment efficiencies that have occurred the historical estimation period. The degree to which the impacts associated with the new lighting standards are manifested in the forecast are not quantifiable and any ad hoc adjustment made to account for the impact of such standards may result in a double counting.

Q. PLEASE COMMENT ON THE MANNER IN WHICH SALES TO THE REMAINING BHE CUSTOMERS WERE FORECASTED.

A. Sales to remaining classes of customers were based on recent history adjusted for known and anticipated changes in consumption quantities over the forecast period. The bulk of the remaining sales are made to relatively few customers, i.e., the paper mills and HoltraChem. This approach used by the Company to project these sales, as well as lighting sales and sales to wholesale customers, is not assessed to be unreasonable.

III. RESIDENTIAL SALES

Q. HAVE YOU DEVELOPED A FORECAST OF SALES TO BHE RESIDENTIAL CUSTOMERS FOR THE RATE-EFFECTIVE PERIOD?

A. Yes. Residential sales for the 12 months ending February 1999 are projected to be 565,205 mWh. This projection is 28,042 mWh higher than the Company's forecast of 537,163 mWh, a difference of 5.2 percent.

Q. PLEASE DESCRIBE THE METHOD THAT YOU USED TO DEVELOP THE RESIDENTIAL SALES FORECAST?

A. Sales to the residential sector were developed econometrically using historical quarterly sales data from the first quarter of 1980 through the first quarter of 1997. The estimated equation is based on a partial adjustment model, described in Schedule___(SLE-1). The estimated econometric equation is shown in Schedule___(SLE-2). The partial adjustment model reflects gradual movement towards the desired, or equilibrium, level of electricity purchases. Electricity is consumed by residential users as a means of obtaining services from electricity-using appliances. Full adjustment to changes in causal factors, such as price and income, require not only adjusting the intensity with which the existing stock of appliances is used, but also adjusting the stock of appliances. Because these appliances are long-lived, adjustments to the stock of appliances is not instantaneous but rather requires several years, that is, adjustments to the appliance stock are made as existing appliances require replacement.

Q. WHAT EXPLANATORY, OR CAUSAL, VARIABLES ARE CONTAINED IN THE RESIDENTIAL SALES EQUATION?

A. Residential sales, defined as average monthly residential sales divided by the average monthly number of residential customers in the calendar quarter, is regressed on a constant term, a lagged dependent variable, the price of electricity, per capita personal income, a weather variable, and three binary dummy variables. Both price and income are expressed in real (constant dollar) terms.

To capture price effects, two price variables are used. The first is computed as the price of 500 kWh per month to residential customers. The second is set equal to the value of the first price variable for the period between the first quarter of 1982 and the fourth quarter of 1986 and set equal to zero for all other periods. Two price variables were used rather than one to capture consumer response to rapid price changes occurring in the early to mid-1980s, which differed from the response to more gradual changes in price over the remainder of the historical period.

Per capita personal income, in real terms, is for the State of Maine as a whole. Maine data, rather than data specific to the BHE service area, was used for the reasons articulated in Mr. Cooper's direct testimony.

The lagged dependent variable, equal to the value of the dependent variable in the same quarter of the previous year, is consistent with the structural formulation associated with the partial adjustment model as presented in Schedule___(SLE-1).

The weather variable (heating degree days and cooling degree days) is expressed in difference form. A difference form is used to preclude weather conditions in one year from affecting usage in subsequent years. Temperature conditions are hypothesized to affect usage only in the short-term. Were the weather variable not expressed in difference form, extremely cold temperatures in the winter of one year would affect usage in subsequent years through the lagged dependent variable. This specification is consistent with the general model form described in Schedule___(SLE-1).

The heating and cooling degree day data were obtained from the National Oceanic Atmospheric Administration of the U.S. Department of Commerce. These data reflect high and low daily temperature readings from the Orono, Maine weather station. For each calender quarter, heating and cooling degree days were lagged one month to help ameliorate the problem of billing lag. For example, the weather variable for the first quarter of 1985 is based on heating and cooling degree days for December 1984 and January and February 1985. Additionally, cooling degree days are multiplied by a factor of two to prevent the influence of cooling degree days from being masked by the numerically larger heating degree day figures.

The inclusion of two of the three binary (0,1) dummy variables eliminates the influence of two outlying observations, identified by large residual (or error) terms. The third dummy, set equal to 1 in the first quarter of each year and zero elsewhere, captures certain seasonal effects not captured by the weather variable. The inclusion of the three dummy variables improved the overall performance of the equation.

Q. WITH RESPECT TO THE SPECIFICATION OF THE WEATHER VARIABLE, WHAT IS MEANT BY THE TERM "BILLING LAG?"

A. Recorded sales in a particular month reflect the meter readings over the course of the month. Meters read in the early part of the month, however, reflect usage over the past approximately 30 days, that is, usage largely occurring during the prior month. The mismatch between usage and recorded sales is known as the billing lag. The degree day data was lagged one month to help ameliorate the problem. The billing lag problem is also reduced with reliance on quarterly sales data rather than monthly sales data.

Q. HOW WAS THE FORECAST DEVELOPED FOLLOWING ESTIMATION OF THE ECONOMETRIC EQUATION?

A. The values of the independent (or causal) variables, as well as the value for the number of residential customers which appears in the denominator of the dependent variable, were projected over the forecast period. When these values are inserted into the equation, future period kWh sales to residential customers can be calculated for each calendar quarter. Because the rate year does not coincide with calendar quarters, the historical percentages of residential sales in each month of the first calendar quarter were relied upon to develop estimates of sales in each of the three individual months within that quarter.

Q. WHAT WAS THE BASIS FOR YOUR PROJECTIONS OF THE VALUES OF THE INDEPENDENT VARIABLES?

A. To compute forecasted residential sales, it was necessary to develop projections of real per capita personal income in Maine, the real price of electricity, the number of residential customers, and weather. Nominal per capita personal income projections were obtained from the State Planning Office and these nominal projections were deflated using projections of the Consumer Price Index (CPI) from Blue Chip Economic Indicators (July 10, 1997). The Blue Chip CPI projections, represented as a consensus, are an average of projections prepared by approximately 50 firms, organizations, and individuals, with the ten highest and lowest projections excluded from the average.

The projections of per capita personal income from the SPO indicated growth in real per capita income in excess of 2 percent per year for all calender quarters in the forecast period. This rate of growth in real per capita income was judged to be too high and a growth rate assumption of 2.0 percent per year was relied upon.

The price of electricity is assumed to increase by 3.79 percent (nominal) in June 1997 and increase by 6.57 percent (nominal) in March 1998. This represents a rate increase of approximately $14.0 million in two steps: $5 million (June 1997) and $9 million (March 1998), which is consistent with the preliminary analysis performed by other Staff witnesses. This forecasting assumption is subject to change pending completion of the analysis by Staff witnesses. The nominal electricity price increase is deflated using the projected CPI values, previously discussed.

The projection of the number of residential customers is based on an assumption of 0.9 percent per year growth. This rate of growth is assessed to be reasonable based on recent historical growth in the number of residential customers and historical and projected growth in population in the four Maine counties served by BHE, as provided by the State Planning Office.

Forecasted weather is simply assumed to equal the 30-year average of heating and cooling degree days for the Orono weather station. These data were obtained from the National Oceanic and Atmospheric Administration.

Schedule___(SLE-4) contains a list of all forecasting assumptions used and the sources relied upon.

Q. WERE ANY ADJUSTMENTS MADE TO THE FORECASTED RESIDENTIAL SALES FIGURES?

A. Yes. The dependent variable used for the historical estimation period was adjusted by adding energy savings associated with the Company's demand-side management programs. That is, the historical usage on which the equation is estimated reflects usage that would have occurred absent any Company-sponsored DSM. The forecasted data were adjusted to subtract the DSM savings for the future period, as estimated by the Company.

In addition, residential sales for the third quarter of 1996 were high relative to sales in previous third quarters. The high level of sales in the third quarter of 1996, to the extent it is attributable to factors not represented in the model, may adversely affect the accuracy of the projections by carrying forward the high third-quarter sales level into the forecast period. Third quarter sales for 1997 and 1998, therefore, were adjusted downward by approximately 33 kWh per residential customer to negate the influence of the third quarter 1996 figure. The per-customer kWh reduction was derived by averaging third quarter kWh per residential customer over the 1991 through 1996 period and eliminating from the average the highest and lowest observations. The resulting average was then subtracted from the third quarter 1996 figure, yielding 11 kWh per customer per month in the summer quarter, or 33 kWh for the quarter as a whole.

Q. WAS ANY UPWARD ADJUSTMENT MADE TO RESIDENTIAL SALES TO REFLECT INCREASED ELECTRIC SPACE HEAT SALES?

A. No. Electric space heat sales increased over the course of the historical period and are, to some degree, captured in the estimated parameters in the econometric equation. Adjusting the forecast upward to account for these anticipated sales may cause a double-counting problem.

IV. COMMERCIAL/INDUSTRIAL SALES

1. Q. HAVE YOU PREPARED AN INDEPENDENT FORECAST OF COMMERCIAL/INDUSTRIAL SALES FOR THE RATE-EFFECTIVE PERIOD?

A. Yes, though much of the data relied upon was developed by the Company.

Q. PLEASE EXPLAIN HOW YOU FORECASTED COMMERCIAL/INDUSTRIAL SALES.

A. To forecast commercial/industrial sales, I developed an econometric equation that relates current quarter commercial/industrial sales to a constant term, a real price variable, a weather variable, the level of commercial/industrial sales in the same quarter of the prior year, and the average number of residential customers in the quarter. The equation is expressed in double logarithmic form, as was the residential equation. As in the residential equation, the weather variable is specified as a difference to preclude weather fluctuations from exerting a long-term effect on energy usage. Additionally, the quarterly degree day observations included in the construction of the weather variable are lagged one month to minimize the effect of billing lag. The estimated econometric equation for the commercial/industrial sales forecast is shown in Schedule___(SLE-3).

Once the econometric equation was estimated, forecasted values of the regressors were inserted into the equation and the forecast was computed.

Q. HOW WERE THE FORECASTED VALUES OF THE REGRESSORS DEVELOPED?

A. The real price projection was developed based on discussions with other Staff witnesses regarding the revenue increase anticipated to be recommended for approval by the Commission based on their analysis. This preliminary assessment was divided by core customer revenues to obtain percentage increases in rates. The assumed nominal percentage increases are identical to those used to forecast residential sales.

The projected weather variable is based on 30-year average weather conditions as recorded by the National Oceanic and Atmospheric Administration at the Orono, Maine weather station, which corresponds to the historical data used to develop the weather variable.

The number of residential customers was assumed to grow at an average annual rate of 0.9 percent, identical to the assumption relied upon for the residential equation.

Q. PLEASE EXPLAIN THE RATIONALE UNDERLYING THE INCLUSION OF THE NUMBER OF RESIDENTIAL CUSTOMERS IN THE COMMERCIAL/INDUSTRIAL SALES EQUATION.

A. The number of residential customers serves as a proxy for the level of economic activity in the BHE service area. Alternative measures of economic activity, such as the level of output or the number of employees, would have been preferable but these data were not available in a sufficiently disaggregated form to permit their use in the specification of the equation.

Q. WHAT ADJUSTMENTS, IF ANY, DID YOU MAKE TO THE ECONOMETRICALLY FORECASTED LEVELS OF COMMERCIAL/INDUSTRIAL SALES?

A. The sales data used for the estimation was adjusted to include the Company-estimated figure for energy savings associated with Company-sponsored demand-side management, that is, the dependent variable used in the equation reflects the level of sales estimated to have occurred absent any Company-sponsored DSM. Forecasted DSM energy savings were then subtracted from the forecasted sales figures to reverse the historical adjustment. No other adjustments to the projections were made.

BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

RE:	BANGOR HYDRO-ELECTRIC	)	
	COMPANY PROPOSED	)	DOCKET NO. 97-116
	INCREASE IN RATES	)	

SCHEDULES ACCOMPANYING

DIRECT TESTIMONY

OF

STEVEN L. ESTOMIN, PH.D.

AUGUST 8, 1997

EXETER
Associates, Inc.
12510 Prosperity Drive
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GENERALIZED SPECIFICATION OF THE ALTERNATIVE ECONOMETRIC EQUATIONS

The "generic" model used for the alternative residential and commercial/industrial models is specified as:

(1) $Y = f(ST, LT)$

where:

Y = the dependent variable;

ST = a variable with only a short-term influence on Y, the dependent variable;

LT = a variable with a long-term influence on Y.

The short-term variable in any period affects the value of the dependent variable in that one period only, that is, only current values of ST affect the current value of Y. Conversely, the value of the long-term variable will influence the value of the dependent variable not only in the current period but in future periods as well. It also follows that past values of the long-term variable will influence the value of the dependent variable in the current period.

It is reasonable to assume that past values of the long-term variable will have a smaller impact upon the value of the dependent variable than do more recent values of the long-term variable. Following this assumption, a Koyck lag structure can be used in the estimations. The following equation is used to reflect the declining influence of the long-term independent variable over time.[1]

(2) $$Y_t = a + b_1(ST_t) + b_2(LT_2) + b_2Z(LT_{t-1}) + b_2Z^2(LT_{t-2}) + b_2Z^3(LT_{t-3}) + \ldots + e_t$$

where:

Y, ST and LT are as previously defined;

a =	a constant (intercept) term;
b_1, b_2 =	parameters to be estimated;
Z =	a parameter that indicates the rate of decay of the influence of the long-term variable ($0 \leq Z \leq 1$);
e =	an error term;
t =	time subscript.

[1]M. Koyck, Distributed Lags and Investment Analysis, Amsterdam: North Holland Publishing Co., 1954 as cited in G. S. Maddala, Econometrics, New York: McGraw-Hill Book Co., 1977, p. 360.

Because the value of Z is typically less than unity, by increasing the power to which Z is raised, the Zs provide a weighting scheme which gives less weight to past values of LT than to more recent values of LT.

Ease of econometric estimation is accomplished by lagging equation (2) by one period and multiplying through by Z. The resulting equation (3) is then subtracted from equation (2) to generate equation (4).

$$(3)\quad ZY_{t-1} = Za + b_1Z(ST_{t-1}) + b_2Z^2(LT_{t-1}) + b_2Z^3(LT_{t-2}) + \ldots + Ze_{t-1}$$

$$(4)\quad Y_t\text{-}ZY_{t-1} = (a\text{-}Za) + b_1(ST_t - ZST_{t-1}) + b_2(LT_t) + (e_t - Ze_{t-1})$$

By rearranging terms, we have:

$$(4')\quad Y_t = a^* + b_1(ST_t - ZST_{t-1}) + b_2(LT_t) + ZY_{t-1} + e^*_t$$

Equation (4') represents the general form of the alternative model estimated for residential energy usage. Note in equation (4') that the short-term variable is expressed in first difference form. On an intuitive level, this is because the effects of past values of the short-term variable are reflected in the lagged dependent variable (Y_{t-1}). The past value of the short-term variable, weighted by the parameter Z, therefore, needs to be subtracted out.

BANGOR HYDRO-ELECTRIC COMPANY

Residential Sales Equation

$$\ln(SALES_t/CUST_t) = -1.367763 + 0.847265 \ln(SALES_{t-4}/CUST_{t-4}) - 0.045604 \ln(PRICE_t)$$
$$- 0.015271 \ln(PRICEA_t) + 0.225743 \ln(INCOME_t) + 0.057823\ WEATHER$$
$$+ 0.028749\ D1 - 0.084835\ D863 + 0.105114\ D853$$

Regressor	Estimated Parameter	Standard Error	t-Statistic
Constant	-1.367763	0.765	-1.788
$SALES_{t-4}/CUST_{t-4}$	0.847265	0.066	12.886
$PRICE_t$	-0.045604	0.027	-1.697
$PRICEA_t$	-0.015271	0.005	-2.973
$INCOME_t$	0.225743	0.072	3.134
$WEATHER_t$	0.057823	0.017	3.341
D1	0.028749	0.015	1.917
D863	-0.084835	0.027	-3.198
D853	0.105114	0.026	3.980

R-squared	0.971
Adjusted R-squared	0.967
S.E. of regression	0.025
Sum of squared residuals	0.034
F-Statistic	237.399
Estimation period	1981, Q1 to 1997, Q1
Number of observations	65
Iterations	1

BANGOR HYDRO-ELECTRIC COMPANY

Residential Sales Equation

Definition of Variables

$SALES_t/CUST_t$	=	Average monthly residential kWh sales (adjusted for DSM) over the calendar quarter divided by the average number of residential customers.
CONSTANT	=	Constant term.
$SALES_{t-4}/CUST_{t-4}$	=	Average monthly residential kWh sales (adjusted for DSM) over the same calendar quarter of the prior year divided by the average number of customers in the same quarter of the prior year.
$PRICE_t$	=	The residential price of 500 kWh per month deflated to real terms using the Consumer Price Index.
$PRICEA_t$	=	$PRICE_t$ for the period 1982Q1 through 1986Q4 and zero elsewhere.
$INCOME_t$	=	Maine real per capita personal income.
D1	=	A binary dummy variable set equal to 1 in the first quarter of each year and zero elsewhere.
D863	=	A binary dummy variable set equal to 1 in the third quarter of 1986 and zero elsewhere.
D853	=	A binary dummy variable set equal to 1 in the third quarter of 1985 and zero elsewhere.
$WEATHER_t$	=	$\ln (HDD_t + 2(CDD_t)) - 0.847265 \ln (HDD_{t-4} + 2(CDD_{t-4}))$

where:

HDD_t = heating degree days for the quarter, lagged one month;
CDD_t = cooling degree days for the quarter, lagged one month;
HDD_{t-4} = heating degree days for the same quarter of the prior year, lagged one month; and

BANGOR HYDRO-ELECTRIC COMPANY
Commercial/Industrial Sales Equation

$$\ln(SALES_t) = -2.304782 + 0.789413 \ln(SALES_{t-4}) - 0.081934 \ln(PRICE)$$

$$+ 0.404497 \ln(CUST) + 0.053930\ WEATHER$$

Regressor	Estimated Parameter	Standard Error	t-Statistic
Constant	-2.304782	1.303	-1.769
$SALES_{t-4}$	0.789413	0.059	13.448
$PRICE_t$	-0.081934	0.027	-3.012
$CUST_t$	0.404497	0.169	2.398
$WEATHER_t$	0.053930	0.018	3.012

R-squared	0.976
Adjusted R-squared	0.975
S.E. of regression	0.031
Sum of squared residuals	0.056
F-Statistic	620.469
Estimation period	1981, Q1 to 1997, Q1
Number of observations	65
Iterations	8

BANGOR HYDRO-ELECTRIC COMPANY

Commercial/Industrial Sales Equation

Definition of Variables

$SALES_t$	=	Commercial/industrial mWh sales (adjusted for DSM) over the calendar quarter.
CONSTANT	=	Constant term.
$SALES_{t-4}$	=	Commercial/industrial mWh sales (adjusted for DSM) over the same calendar quarter of the prior year.
$PRICE_t$	=	The general service price of 1,000 kWh per month deflated to real terms using the Gross Domestic Product implicit price deflator.
$CUST_t$	=	The average number of residential customers over the calendar quarter.
$WEATHER_t$	=	$\ln(HDD_t + 2(CDD_t)) - 0.789413 \ln(HDD_{t-4} + 2(CDD_{t-4}))$

where:

HDD_t = heating degree days for the quarter, lagged one month;
CDD_t = cooling degree days for the quarter, lagged one month;
HDD_{t-4} = heating degree days for the same quarter of the prior year, lagged one month; and
CDD_{t-4} = cooling degree days for the same quarter of the prior year, lagged one month.

BANGOR HYDRO-ELECTRIC COMPANY
FORECASTING ASSUMPTIONS

ELECTRICITY PRICE (NOMINAL)

Assumed to increase 3.788 percent in June 1997 and increase 6.569 percent in March 1998. Source: Preliminary rate increase recommendations prepared by other Staff witnesses.

PER CAPITA PERSONAL INCOME (REAL)

Assumed to increase by 2.0 percent per year throughout the forecast period. Source: Maine State Planning Office, "Maine Counties: Selected Economic Measures, History and Forecasts," May 1997, Table "Per Capita Personal Income." Note: SPO provided nominal per capita income growth projections that implied real growth in excess of 2.0 percent. The SPO figures were judgmentally adjusted downward to 2.0 percent per year.

RESIDENTIAL CUSTOMERS

Assumed to grow at 0.9 percent per year throughout forecast period. Source: Historical growth in customers was compared to historical growth in population in the four counties served by BHE. Forecasted population growth in these counties was multiplied by the historical ratio, suggesting growth of 0.985 percent per year. This was adjusted downward to 0.9 percent to more closely reflect recent customer growth history.

WEATHER

Thirty-year average heating and cooling degree days. Source National Oceanic and Atmospheric Administration, monthly data summary tables for Orono, Maine weather station.

Consumer Price Index

	Percentage Change from Same Quarter of Prior Year
Q2 1997	2.6
Q3	2.6
Q4	2.4
Q1 1998	2.5
Q2	2.8
Q3	2.9
Q4	2.9
Q1 1999	2.9

Source: Blue Chip Economic Indicators (Vol. 22, No. 7), July 10, 1997, page 5, Table 4. The projections are provided only through the fourth quarter of 1998. The first quarter of 1999 was assumed to equal the fourth quarter of 1998.

GDP Deflator

	Percentage Change from Same Quarter of Prior Year
Q2 1997	2.0
Q3	2.0
Q4	2.3
Q1 1998	2.2
Q2	2.4
Q3	2.5
Q4	2.4
Q1 1999	2.4

Source: Blue Chip Economic Indicators (Vol. 22, No. 7), July 10, 1997, page 5, Table 4. The projections are provided only through the fourth quarter of 1998. The first quarter of 1999 was assumed to equal the fourth quarter of 1998.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

DELTA NATURAL GAS COMPANY, INC.	))	Case No. 99-176

DIRECT TESTIMONY

OF

STEVEN L. ESTOMIN, Ph.D.

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL

FOR THE COMMONWEALTH OF KENTUCKY

SEPTEMBER 1999

EXETER

Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

DELTA NATURAL GAS COMPANY, INC.	))	Case No. 99-176

DIRECT TESTIMONY OF STEVEN L. ESTOMIN

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven L. Estomin. My business address is 12510 Prosperity Drive, Suite 350, Silver Spring, Maryland, 20904. Exeter is an economics consulting firm specializing in public utility regulation.

Q. WHAT IS YOUR POSITION WITH EXETER ASSOCIATES, INC.?

A. I am a vice president and principal in the firm and my title is Senior Economist. My responsibilities include conducting and presenting economic and econometric analyses and providing other professional services predominantly related to regulated industries.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND BACKGROUND.

A. I received a Bachelor of Arts degree with a major in economics in 1975, a Master of Arts degree in economics in 1978, and a Ph.D. in economics in 1986, all from the University of Maryland. My areas of specialization in graduate school were industrial organization, econometrics, and environmental economics.

I joined Exeter Associates, Inc. in 1981 as an economist and have been involved with economic analysis related to regulated industry since that time. A detailed statement of my qualifications is included as an appendix to this testimony.

Q. HAVE YOU TESTIFIED AS AN EXPERT WITNESS IN OTHER REGULATORY PROCEEDINGS?

A. Yes. I have testified before the utility commissions in Maine, Maryland, Vermont, New Mexico, New Jersey, Illinois, Rhode Island, and the District of Columbia on issues related to load forecasting, weather normalization, production planning, statistical analysis and other issues. I have also testified in U.S. District Court and before the Federal Energy Regulatory Commission on issues related to statistical estimation.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was requested by the Attorney General Office of Rate Intervention to assess the testimony and exhibits of Company witness Seelye regarding the application of the zero-intercept approach to functionalizing distribution system costs.

Q. IS YOUR TESTIMONY ACCOMPANIED BY EXHIBITS?

Q. Yes. Exhibit___SLE-1, a seven-page exhibit, is attached which provides the regression results used to develop the tables contained in my testimony and the data relied upon to run the regressions..

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. The findings of my review and analysis are:

- Mr. Seelye relies on a weighted least square regression approach in his zero-intercept analysis using the square root of the number of feet of each pipe size category rather than the number of feet, as suggested in his direct testimony.
- Use of the square root of the number of feet results in an estimated zero-intercept that is approximately 66 percent higher than the estimate obtained using the number of feet of mains as the weights.
- Use of the number of feet rather than the square root of the number of feet in the weighted regression is consistent with NARUC guidelines and results in better goodness-of-fit measures.
- Use of Ordinary Least Squares regression is more appropriate than using weighted least squares given the nature of the application of the results.

II. Review and Analysis

Q. PLEASE DESCRIBE THE ZERO-INTERCEPT METHOD OF FUNCTIONALIZING DISTRIBUTION SYSTEM COSTS.

A. The zero-intercept method is one of two approaches used to classify distribution system costs between a hypothesized customer-related component and a demand-related component of distribution mains investment cost. The other approach is referred to as the minimum system approach.

The zero-intercept method entails estimating a regression equation that has average costs per unit of distribution system (e.g., average cost per foot of distribution main) as the dependent variable and uses a size measure of the distribution component (e.g., diameter of pipe) as the independent, or causal, variable. Separate observations are made up of various size categories. Where warranted, other salient characteristics are used to delineate observations, for example, 3-inch pipe may be broken down into separate categories for plastic and steel. The regression equation is structured as:

$$Y_i = a + bX_i + e_i$$

where:

Y_i = average cost per unit of distribution system for category i;

a = constant term;

b = slope parameter;

X_i = the size dimension of category i; and

e_i = the randomly distributed error term associated with category i.

The estimated constant term (a) is the intercept along the vertical axis and can be interpreted as the per-unit cost of a zero-size distribution main, i.e., a distribution main with no carrying capacity.

Q. HAVE YOU REVIEWED MR. SEELYE'S TESTIMONY AND EXHIBITS RELATED TO THE REGRESSION EQUATION USED IN HIS ZERO-INTERCEPT ANALYSIS?

A. Yes, I have.

Q. IS THE APPROACH THAT YOU DESCRIBED ABOVE USED BY MR. SEELYE?

A. Yes, but with an important variation. Rather than relying on the equation discussed above, which is estimated using Ordinary Least Squares (OLS) regression, the Company uses weighted least squares, where the Y_i and X_i components (average cost per unit of distribution mains and size of mains, respectively) are weighted. The purpose of the weighting, as explained by Mr. Seelye at pages 12-13 of his direct testimony, is to reflect that the Company's distribution system is composed of different quantities (feet) of mains of different sizes. For example, the Company has 1.1 million feet of four-inch plastic pipe and 430,000 feet of two-inch steel pipe.

Q. WHAT WEIGHTING SCHEME IS USED BY THE COMPANY?

A. The Company uses the square root of the number of feet of distribution main in each category as the weights. The use of the square root of the number of feet is clear from Mr. Seelye's Exhibit 4-2, though the text of his testimony suggests that the weights used were the feet of main. (Seelye Direct Testimony, page 13.)

Q. WHAT ARE THE IMPLICATIONS OF USING THE SQUARE ROOT OF THE NUMBER OF FEET OF MAINS IN EACH CATEGORY COMPARED TO USING THE NUMBER OF FEET OF MAINS AS THE WEIGHTS?

A. The OLS algorithm generates estimates of the equation parameters, the "a" and the "b" terms, by minimizing the sum of squared errors, that is,

$$\Sigma (Y_i - (a + bX_i))^2$$

where all terms are as previously defined.

In contrast, the weighted least squares algorithm relies on minimization of

$$\Sigma w_i^2 (Y_i - (a + bX_i))^2$$

where w_i is the weight given to each category and all other terms are as previously defined.

By using the square root of the number of feet as the weight, the w_i^2 term in the above expression is the number of feet of main. Alternatively stated, using the square root of feet serves to weight the squared error terms by the number of feet (i.e., the square of the square root). Reliance on the square root of the number of feet as a weight rather than the number of feet significantly affects the results of the equation.

Q. IS THE USE OF A SQUARE ROOT TERM FOR WEIGHTS COMMONLY USED IN WEIGHTED LEAST SQUARES REGRESSION?

A. The square root of a data series such as the number of feet of mains is often used where weighted least squares is relied upon to correct for heteroscedasticity, a statistical problem that sometimes emerges with the use of OLS.[1] There is no evidence of heteroscedasticity with respect to the subject equation.

Q. YOU NOTED THAT THE USE OF FEET AS A WEIGHT, RATHER THAN THE SQUARE ROOT OF FEET, RESULTS IN SUBSTANTIALLY DIFFERENT REGRESSION OUTPUT. PLEASE EXPLAIN.

[1]Heteroscedasticity results when the variance of the error terms is not constant.

A. I replicated the weighted least squares regression results obtained by Mr. Seelye and then reran the regression using feet as the weights rather than the square root of feet. A summary comparison is shown in the table below.

Comparison of Regression Results Using
Alternative Weighting Schemes
(t - Statistics in parentheses)

	Weight: square root of feet[1]	Weight: number of feet[2]	Weight: none[3]
Constant	3.141 (2.38)	1.891 (2.23)	1.809 (1.23)
Size Parameter	0.860 (1.93)	1.562 (4.18)	0.771 (2.22)
R-Square	0.829	0.977	0.354
Adjusted R-Square	0.810	0.975	0.282
F-Statistic	3.738	17.470	4.929

1. Exhibit__SLE-1, page 1 of 7.
2. Exhibit__SLE-1, page 2 of 7.
3. Exhibit__SLE-1, page 3 of 7.

As shown in the table, the Company's weighting scheme results in an estimate of the constant term (the zero-intercept) of 3.14 compared to1.89 where feet are used as weights. Additionally, use of feet as weights results in a higher R-square and Adjusted R-square statistics, which are measures of goodness of fit.

Q. DO YOU VIEW THESE DIFFERENCES IN THE REGRESSION RESULTS AS A PROBLEM?

A. Yes. Fundamentally, the selection of the weights used in the weighted regression substantially alters the results. The zero-intercept obtained using the square root of feet as the weighting is approximately 66 percent higher than the zero-intercept estimated using the number of feet as the weight. Consequently, we see that the results are highly sensitive to a judgmental assessment of an appropriate weighting scheme.

Q. IS THE WEIGHTING SCHEME USING THE SQUARE ROOT OF FEET SUGGESTED BY THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC)?

A. No. The NARUC *Electric Utility Cost Allocation Manual* (January 1992), in discussing use of the zero-intercept method as applied to electric distribution systems, indicates at page 92 that the number of poles (not the square root of the number of poles) should be used for Account 364 (Poles, Tower, and Fixtures); for Account 365 (Overhead Conductors and Devices), NARUC indicates that number of feet (not the square root of the number of feet) should be used as a weight (page 92). The same is true for Accounts 366, 367, and 368 (pages 93 and 94).

Q. BASED ON THE NARUC DOCUMENT AND THE GOODNESS-OF-FIT MEASURES SHOWN IN THE SUMMARY COMPARISON TABLE, IS THE USE OF THE SQUARE ROOT OF THE NUMBER OF FEET AS A WEIGHTING SCHEME APPROPRIATE?

A. Both the NARUC document as well as the comparison of results suggest that, were one to rely on a weighting scheme, the number of feet rather than the square root of the number of feet would be a superior choice.

Q. ARE YOU RECOMMENDING THAT THE NUMBER OF FEET BE USED TO WEIGHT THE REGRESSION?

A. No. Despite NARUC's suggestions regarding weighting, I can see little advantage, and a significant disadvantage, to using weighted least squares for the purpose of estimating the zero-intercept to define the cost of the minimum system.

Q. PLEASE EXPLAIN.

A. The zero-intercept method is used to quantify, through regression analysis, the cost of the minimum system. The major disadvantage of using the weighted least squares approach can be seen by example. If we hypothesize a second gas company with the same system as Delta in terms of net cost and length of pipe in each size/type category, we would expect the cost of the minimum system for Delta and the second company to be the same. If the second company then doubles the length of 2-inch steel pipe with the same average cost per foot as the original length of 2-inch steel pipe, the use of a weighted regression will cause a different zero-intercept to be estimated for that company; an unweighted regression, in contrast, will not result in any changes to the estimated zero-intercept. There appears to be no compelling explanation as to why the minimum system costs on a per foot basis should change as a result of this difference between the two companies (i.e., Delta and the hypothetical). A comparison of the regression results is shown in the following table.

Comparison of Weighted Least Squares Results
for Delta and a Hypothetical Company with
Twice the Length of 2-inch Steel Main

	Weight: Square Root of Feet		Weight: Feet	
	Delta[1]	Hypothetical[2]	Delta[3]	Hypothetical[4]
Constant	3.141	2.696	1.891	1.628
Slope Parameter	0.860	0.946	1.562	1.622
R-Square	0.829	0.782	0.977	0.955
Adjusted R-Square	0.810	0.757	0.975	0.950
F-Statistic	3.738	3.659	17.740	9.607

1. Exhibit___SLE-1, p. 1 of 7; data from p. 6 of 7.
2. Exhibit___SLE-1, p. 4 of 7; data from p. 7 of 7.
3. Exhibit___SLE-1, p. 2 of 7; data from p. 6 of 7.
4. Exhibit___SLE-1, p. 5 of 7; data from p. 7 of 7.

Using the square root of feet as a weight, the estimated zero-intercept is shown to decline by approximately 14.2 percent when the amount of 2-inch steel main is doubled. With feet used as a weight, the zero-intercept declines by approximately 13.9 percent. Were no weights used, there would be no change in the regression equation results.

Q. DO THE GOODNESS-OF-FIT MEASURES SHOWN ON THE SUMMARY COMPARISON TABLE ON PAGE 6 OF YOUR TESTIMONY SUGGEST RELIANCE ON A WEIGHTED OLS APPROACH?

A. The goodness-of-fit measures (R-Square and Adjusted R-Square) are substantially lower for the unweighted regression than for either of the two weighted regressions. Low R-Square measures, however, are not surprising given the nature of the cost data. Specifically, the cost information is accounting data booked over a long period of time. Further, the purpose to which the results are to be put logically calls for an unweighted rather than weighted approach, NARUC's recommendations not withstanding. In particular, each of the data points imparts cost information of equivalent value from a statistical vantage point. The cost information associated with pipes representing a relatively small portion of the system, therefore, should not be given less weight than the other data observations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

DELTA NATURAL GAS COMPANY, INC.	))	Case No. 99-176

EXHIBIT ACCOMPANYING THE

DIRECT TESTIMONY

OF

STEVEN L. ESTOMIN, Ph.D.

ON BEHALF OF THE

OFFICE OF RATE INTERVENTION OF THE ATTORNEY GENERAL

FOR THE COMMONWEALTH OF KENTUCKY

SEPTEMBER 1999

EXETER
Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

Replication of Company's Estimation Output

Dependent Variable: COST_FT
Method: Least Squares
Date: 09/21/99 Time: 15:18
Sample: 1 11
Included observations: 11
Weighting series: FEET_SQRT

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3.141087	1.317330	2.384435	0.0409
SIZE	0.859844	0.444726	1.933423	0.0852

Weighted Statistics

R-squared	0.828622	Mean dependent var	5.140887
Adjusted R-squared	0.809580	S.D. dependent var	5.553482
S.E. of regression	2.423383	Akaike info criterion	4.771171
Sum squared resid	52.85505	Schwarz criterion	4.843516
Log likelihood	-24.24144	F-statistic	3.738126
Durbin-Watson stat	1.345648	Prob(F-statistic)	0.085204

Unweighted Statistics

R-squared	-0.046696	Mean dependent var	4.683769
Adjusted R-squared	-0.162996	S.D. dependent var	2.770680
S.E. of regression	2.987965	Sum squared resid	80.35142
Durbin-Watson stat	0.972115		

Data: Data Set I

Estimation Output with Feet as Weighting Series

Dependent Variable: COST_FT
Method: Least Squares
Date: 09/02/99 Time: 10:10
Sample: 1 11
Included observations: 11
Weighting series: FEET

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1.890932	0.849174	2.226790	0.0530
SIZE	1.561923	0.373687	4.179767	0.0024

Weighted Statistics

R-squared	0.977103	Mean dependent var	5.432648
Adjusted R-squared	0.974559	S.D. dependent var	9.705736
S.E. of regression	1.548084	Akaike info criterion	3.874879
Sum squared resid	21.56907	Schwarz criterion	3.947223
Log likelihood	-19.31183	F-statistic	384.0683
Durbin-Watson stat	1.120536	Prob(F-statistic)	0.000000

Unweighted Statistics

R-squared	-1.332791	Mean dependent var	4.683769
Adjusted R-squared	-1.591990	S.D. dependent var	2.770680
S.E. of regression	4.460701	Sum squared resid	179.0807
Durbin-Watson stat	0.478258		

Data: Data Set I

Estimation Output without Weights

Dependent Variable: COST_FT
Method: Least Squares
Date: 09/02/99 Time: 10:10
Sample: 1 11
Included observations: 11

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1.809454	1.475481	1.226348	0.2512
SIZE	0.771158	0.347336	2.220206	0.0535

R-squared	0.353881	Mean dependent var	4.683769
Adjusted R-squared	0.282090	S.D. dependent var	2.770680
S.E. of regression	2.347586	Akaike info criterion	4.707618
Sum squared resid	49.60045	Schwarz criterion	4.779963
Log likelihood	-23.89190	F-statistic	4.929315
Durbin-Watson stat	1.607570	Prob(F-statistic)	0.053546

Data: Data Set I

Estimation Output with Altered Weights (Sq Root Feet)

Dependent Variable: COST_FT
Method: Least Squares
Date: 09/21/99 Time: 15:25
Sample: 1 11
Included observations: 11
Weighting series: FEET_SQRT2

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.695667	1.439776	1.872283	0.0940
SIZE	0.945863	0.494502	1.912759	0.0881

Weighted Statistics

R-squared	0.781728	Mean dependent var	4.991149
Adjusted R-squared	0.757476	S.D. dependent var	5.299900
S.E. of regression	2.610028	Akaike info criterion	4.919565
Sum squared resid	61.31022	Schwarz criterion	4.991909
Log likelihood	-25.05761	F-statistic	3.658645
Durbin-Watson stat	1.374775	Prob(F-statistic)	0.088072

Unweighted Statistics

R-squared	-0.002959	Mean dependent var	4.683769
Adjusted R-squared	-0.114399	S.D. dependent var	2.770680
S.E. of regression	2.924872	Sum squared resid	76.99388
Durbin-Watson stat	1.001205		

Data: Data Set II

Estimation Output with Altered Weights (Feet)

Dependent Variable: COST_FT
Method: Least Squares
Date: 09/21/99 Time: 16:10
Sample: 1 11
Included observations: 11
Weighting series: FEET2

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1.627573	1.184412	1.374161	0.2026
SIZE	1.622080	0.523334	3.099511	0.0127

Weighted Statistics

R-squared	0.954583	Mean dependent var	5.177354
Adjusted R-squared	0.949536	S.D. dependent var	9.064424
S.E. of regression	2.036242	Akaike info criterion	4.423054
Sum squared resid	37.31653	Schwarz criterion	4.495399
Log likelihood	-22.32680	F-statistic	9.606965
Durbin-Watson stat	1.400800	Prob(F-statistic)	0.012733

Unweighted Statistics

R-squared	-1.357808	Mean dependent var	4.683769
Adjusted R-squared	-1.619787	S.D. dependent var	2.770680
S.E. of regression	4.484556	Sum squared resid	181.0012
Durbin-Watson stat	0.486061		

Data: Data Set II

Data Set I

obs	FEET	FEET_SQRT	SIZE	COST_FT
1	442766.0	665.4066	1.500000	5.038960
2	3625826.	1904.160	2.000000	5.016380
3	56307.00	237.2910	3.000000	2.389830
4	1077977.	1038.257	4.000000	9.201620
5	51168.00	226.2034	6.000000	8.271420
6	108137.0	328.8419	1.500000	1.445490
7	429630.0	655.4617	2.000000	1.327470
8	73925.00	271.8915	3.000000	1.280910
9	259512.0	509.4232	4.000000	5.384780
10	273679.0	523.1434	6.000000	5.727550
11	79984.00	282.8144	8.000000	6.437050

Reference: S. Seelye, Exhibit 4-1.

Data Set II - Altered Obs. 7

obs	FEET2	FEET_SQRT2	SIZE	COST_FT
1	442766.0	665.4066	1.500000	5.038960
2	3625826.	1904.160	2.000000	5.016380
3	56307.00	237.2910	3.000000	2.389830
4	1077977.	1038.257	4.000000	9.201620
5	51168.00	226.2034	6.000000	8.271420
6	108137.0	328.8419	1.500000	1.445490
7	859260.0	926.9628	2.000000	1.327470
8	73925.00	271.8915	3.000000	1.280910
9	259512.0	509.4232	4.000000	5.384780
10	273679.0	523.1434	6.000000	5.727550
11	79984.00	282.8144	8.000000	6.437050

Reference: S. Seelye, Exhibit 4-1 with observation No. 7 modified.

BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

RE: BANGOR HYDRO-ELECTRIC COMPANY PROPOSED INCREASE IN RATES	)))	DOCKET NO. 97-116

SURREBUTTAL TESTIMONY

OF

STEVEN L. ESTOMIN, PH.D.

ON BEHALF OF THE

MAINE PUBLIC UTILITIES COMMISSION STAFF

OCTOBER 1997

EXETER

Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

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BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

RE: BANGOR HYDRO-ELECTRIC COMPANY PROPOSED INCREASE IN RATES	)))	DOCKET NO. 97-116

SURREBUTTAL TESTIMONY OF STEVEN L. ESTOMIN

Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven L. Estomin. By business address is Exeter Associates, Inc., 12510 Prosperity Drive, Suite 350, Silver Spring, Maryland, 20904.

Q. ARE YOU THE SAME STEVEN L. ESTOMIN WHO PROVIDED DIRECT TESTIMONY REGARDING BANGOR HYDRO-ELECTRIC COMPANY'S SHORT-TERM SALES FORECAST IN DOCKET NO. 97-116 ON BEHALF OF THE MAINE PUBLIC UTILITIES COMMISSION STAFF?

A. Yes.

Q. WHAT IS THE SCOPE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. My surrebuttal testimony provides an update to the residential sales forecast presented in my Direct Testimony, which incorporates actual customer, sales, and weather data for the second and third quarters of 1997. Additionally, in his Rebuttal Testimony, Mr. Cooper identified a data error contained in the price series that I used to develop the residential sales forecast contained in my Direct Testimony. The updated forecast presented herein was made using an equation estimated with a corrected price series.

Based on information contained in Mr. Cooper's and Dr. Criner's Rebuttal Testimonies, and following additional analysis and testing, I have adopted the Company's commercial/industrial energy sales forecast. The reasons underlying this position are fully explained in following pages. Finally, my testimony addresses certain statements and exhibits contained in the rebuttal testimonies of BHE witnesses Mr. Cooper and Dr. Criner.

Q. HOW IS YOUR SURREBUTTAL TESTIMONY ORGANIZED?

A. The next section of my testimony contains the results of the updated forecast and a comparison of the results of the updated forecast with the Company's forecast. The third section addresses the residential sales forecast and the issues identified by Mr. Cooper and Dr. Criner on rebuttal related to the residential sales forecast. The fourth section discusses the development of the updated residential sales forecast.

A fifth section addresses certain general issues developed by BHE witnesses on rebuttal. This is followed by a section addressing the Company's residential model. The final section discusses the commercial/industrial sales forecast and the reasons underlying the Staff's adoption of the Company's forecast of commercial/industrial sales for the 12 months ending February 1999.

Q. IS YOUR TESTIMONY ACCOMPANIED BY SCHEDULES?

A. Yes. Schedule___(SLE-1) presents the revised residential sales econometric equation underlying the updated sales forecast.

Forecast Summary

Q. PLEASE SUMMARIZE YOUR FORECAST RESULTS.

A. The table below shows actual 1996 sales, projected sales for 1997 (which include actual sales for a portion of the year), and forecasted sales for the 12 months ending February 1999. The forecast shown is identical to the Company's forecast with the exception of

Bangor Hydro-Electric Company

Actual and Forecasted Sales (mWh),
Growth Rate (%) from Prior Year

	1996[1]	1997[2]	Year Ending February 1999[3]
Residential	536,490	537,339 (+0.1%)	553,747 (+2.6%)
Commercial	508,363	512,800 (+0.9%)	517,803 (+0.8%)
Industrial	164,172	169,072 (+3.0%)	166,958 (-1.1%)
Paper Mills	260,042	264,928 (+1.9%)	265,000 (+0.0)
HoltraChem	227,841	227,841 (0.0%)	227,841 (0.0%)
Wholesale	4,486	4,500 (+0.3%)	4,500 (0.0%)
Lighting	8,944	9,087 (+1.6%)	8,928 (-1.5%)
Total	1,710,339	1,725,567 (+0.9%)	1,744,777 (1.0%)
Total less HoltraChem and Paper Mills	1,222,456	1,232,798 (0.8%)	1,251,936 (1.3%)

(1) Actual.
(2) Three months actual, nine months forecasted for all categories of sales except residential, which is nine months actual and three months forecasted.
(3) Average annual growth rate from 1997.

sales to residential customers. Sales to residential customers are projected to grow at an average annual rate of 1.47 percent between 1996 and the 12 months ending February 1999. This compares with the Company's projection of 0.60 percent.

Residential Sales

Q. AT PAGES 18 TO 19 OF HIS REBUTTAL TESTIMONY, MR. COOPER IDENTIFIES TEN ISSUES THAT HE CHARACTERIZES AS PROBLEMS RELATED TO YOUR RESIDENTIAL SALES FORECAST. CAN YOU PLEASE ADDRESS THESE ISSUES?

A. Yes. Of the ten issues identified by Mr. Cooper, five relate to the price variables, two relate to the weather variable, one relates to the income variable, and two are categorized as "general." He is correct in one of the areas he identifies as a problem. The remaining nine issues are either without substance, redundant, or wrong.

Q. PLEASE DISCUSS THE PROBLEM THAT YOU BELIEVE MR. COOPER CORRECTLY IDENTIFIED.

A. Mr. Cooper has correctly identified a data error in the calculation of the price variable used in the residential sales equation. Following his identification of this error, I have corrected the mistake and the forecast results contained in my Surrebuttal Testimony reflect this correction.

Q. PLEASE COMMENT ON THE REMAINING PRICE-RELATED ISSUES IDENTIFIED BY MR. COOPER.

A. Mr. Cooper states that the price variable that I relied upon "... does not take seasonal pricing into account ..." (page 18, line 5). This statement is precisely wrong. The price variable reflects seasonal variations in price, which is what the consumer observes and makes usage decisions upon. Mr. Cooper seems to be suggesting that because I did not obfuscate seasonal variations in price through some arithmetic device such as a moving average, that a problem emerges. Reliance on seasonal prices is both correct and appropriate.

Mr. Cooper's concern is that because a portion of the historical period was characterized by higher winter-season prices, the econometric algorithm is unable to properly attribute higher winter-season usage levels to weather conditions and instead attributes those to price. The ability of the least squares algorithm to appropriately estimate the parameters associated with individual causal factors depends on complex interactions among the variables. While the concern expressed by Mr. Cooper sometimes is warranted, in this case it is not. Reasonable values for the estimated price elasticity suggest that the problems that sometimes arise with respect to estimating equations containing seasonally differentiated rates have not materialized in the estimation of the residential sales equation.

A second issue raised by Mr. Cooper, and echoed by Dr. Criner, relates to my use of an interactive dummy variable (i.e., a slope shift dummy) applied to a subperiod within the estimation period. This neither results in multicollinearity problems nor conflicts with economic theory. In short, this issue is in no sense problematic.

Mr. Cooper notes that my description of the mid-1980s as a period of rapid price increase is incorrect. This statement relates back to the calculation error in the price variable that was originally relied upon and is hence redundant.

Finally, Mr. Cooper notes that the estimated parameter on the price variable is significant at the 90 percent level. Why he chooses to characterize this as a problem is unclear. I do not view this as a problem and do not understand why Mr. Cooper does.

Q. PLEASE ADDRESS THE ISSUES RAISED BY MR. COOPER WITH RESPECT TO THE WEATHER VARIABLE CONTAINED IN THE RESIDENTIAL SALES EQUATION.

A. Mr. Cooper indicates that the weighting of cooling degree days by a factor of two is problematic. He expands on this issue in pages 34 through 38 of his Rebuttal Testimony. To put his concern in perspective, it should be noted that Mr. Cooper's own analysis indicates a 1.8-to-1.0 relationship between heating degree days and cooling degree days, which is very close to the 2.0-to-1.0 relationship imposed on the Staff's model. Second, there are relatively few cooling degree days in the BHE service territory relative to heating degree days. Consequently, the importance of this issue is trivial.

Q. ARE THERE OTHER ISSUES RELATED TO THE RESIDENTIAL EQUATION WEATHER VARIABLE RAISED BY MR. COOPER?

A. Yes. Mr. Cooper characterizes my use of a one-month lag in weather to compensate for billing lag as a "red herring." (page 46, line 19.) I have found this formulation to represent a marginal improvement to the correspondence of weather and usage. In my Direct Testimony, I characterized Mr. Cooper's approach of using weather data contemporaneous with recorded sales data as neither incorrect nor necessarily inferior. In fact, no issue was made of this at all. Consequently, I must take strong exception to Mr. Cooper's characterization of my use of lagged weather data as a "red herring," which implies an attempt on my part to misdirect the attention of the Commission. Mr. Cooper's implication is both unwarranted and unfounded.

Q. WHAT IS MR. COOPER'S CRITICISM RELATED TO THE PER CAPITA REAL INCOME VARIABLE USED IN STAFF'S RESIDENTIAL SALES FORECAST?

A. Mr. Cooper's criticism relates to the assumed growth in per capita real income over the forecast period. Mr. Cooper's contention is that because the State Planning Office's May 1997 forecast of per capita nominal income was converted to real dollars using the July 1997 Blue Chip Economic Indicators forecast of the Consumer Price Index, the growth in real per capita income is overstated. The reason for this, according to Mr. Cooper, is that the July CPI projection is lower than previous projections, hence growth in real per capita income would be overstated.

The SPO projects average annual growth in nominal per capita income of 5.22 percent between 1994 and 2000. Reliance on the July 1997 CPI projection would have resulted in an income growth rate assumption of approximately 2.5 percent over the forecast period. Instead, a 2.0 percent growth rate was assumed. (Page 17, line 25 to page 28, line 2 of the Direct Testimony of Steven L. Estomin.) This assumption has the same effect of imposing a CPI forecast assumption of approximately 3.2 percent per year. Since mid-1995, the consensus forecasts shown in Blue Chip Economic Indicators have been consistently below 3.2 percent. Consequently, while it is generally correct that over the past two years the CPI projections have tended to move downwards, the adjustment made to the real per capita income projection is consistent with the highest consensus projections made over that timeframe.

Q. DOES MR. COOPER COMMENT ON THE PATTERN OF RESIDUALS IN THE RESIDENTIAL MODEL?

A. Yes. At page 53 of his Rebuttal Testimony, Mr. Cooper notes that "[t]hose residuals have been getting more negative in the recent past. He [Estomin] has been over-forecasting sales." In point of fact, in the last two years of the historical period, 6 of the 8 quarters of the residential sales equation presented in my Direct Testimony display positive residuals. The same statement is true for the residential sales equation presented in Schedule___(SLE-1), herein.

Q. AT PAGES 29 TO 31, MR. COOPER DISCUSSES CUSTOMER RESPONSE TO CHANGES IN PRICE AND INCOME. WHAT IS HIS CONCERN REGARDING THIS ISSUE?

A. Mr. Cooper notes that the Koyck lag structure employed in my residential model "... forces the customer response rate to be the same for both price and income." To clarify this issue, it must be noted that the model does not depict customer response to changes in price that are the same as the customer response to changes in income. The income elasticity and own-price elasticity are not forced into equality. The model does, however, force equality between the ratios of the short-run to the long-run elasticities. Alternatively stated, the pattern of partial adjustment to the desired level of consumption given a change in income is identical to the pattern of partial adjustment to the desired level of consumption given a change in price. This is, in fact, a shortcoming of the Koyck lag approach. There are, however, several advantages of this approach which outweigh this shortcoming. The Koyck lag approach provides a reasonable and intuitively appealing adjustment scheme whereby adjustment to changes in long-run variables is more rapid in the early periods and less rapid in later periods. Furthermore, the mechanics of the Koyck lag construct conserve on the number of parameters that need to be estimated. Alternative lag constructs that do not force the same rate of decay in the effects of the long-run variables, such as polynomial distributed lags, offer the advantage of allowing different rates of decay but carry serious disadvantages as well. Ultimately, the decision on the selection of an appropriate lag mechanism is largely judgmental and entails balancing advantages and shortcomings of the alternative approaches.

It is also important to note that an econometric sales equation is designed to be a reasonable representation of consumer response to changes in important causal variables. It is not designed to replicate reality, as Mr. Cooper suggests at page 31, line 10. The Koyck lag construct is a useful tool in developing a model consistent with economic theory and intuition, and having desirable forecasting properties.

Q. DOES MR. COOPER'S RESIDENTIAL SALES FORECASTING MODEL ACCOMMODATE DIFFERENTIAL RESPONSE TO CHANGES IN PRICE AND INCOME?

A. His weather-normalization equation does accommodate some manner of differential response. Consumers are restricted to respond to changes in income only in the contemporaneous period. Through the use of an eight-quarter moving average price variable, response to a change in price occurs over a two-year period such that a change in price occurring two years ago has the same effect as one occurring in the current quarter. Clearly, the restrictions and constraints built into his model are substantially more severe than the restrictions associated with use of a Koyck lag.

Q. AT PAGE 63 OF HIS REBUTTAL TESTIMONY, MR. COOPER STATES THAT YOU ARE "... INCORRECT IN SAYING THAT A PRICE CHANGE THAT OCCURRED TWO YEARS AGO HAS THE SAME EFFECT AS ONE THAT OCCURS IN THE CURRENT QUARTER." IS HIS VIEW CORRECT?

A. No. Customer response to changes in price are measured through the price elasticity, which is defined as the percentage change in quantity purchased divided by the percentage change in price. It is the change in price that induces a customer response. The change in price for each of the eight quarters comprising Mr. Cooper's moving average price variable is the same in each quarter for a period of two years following a price change. Mr. Cooper's contention is based on some apparent confusion over the difference between the level of prices and the change in the level of prices.

<u>Updated Residential Sales Forecast</u>

Q. HAVE YOU MADE ANY MODIFICATIONS TO YOUR RESIDENTIAL SALES FORECAST FROM THE FORECAST OF RESIDENTIAL SALES PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes. I re-estimated the model correcting for a data error in the electricity price variable identified by Mr. Cooper in his Rebuttal Testimony. The structure of the model is unchanged and in general there are only minor changes in the values of the estimated parameters. The revised residential sales equation, along with summary statistics and specifications of the variables shown, is contained in Schedule___(SLE-1).

In addition, I updated the data set to reflect the most recent data available through the third quarter of 1997. These data (sales, customers, and degree days) were incorporated into the historical data set, the forecast period was modified from the second quarter of 1997 (Direct Testimony) to the fourth quarter of 1997 (Surrebuttal Testimony). Consequently, the lagged 1997 values of sales per residential customer and degree days, which influence the 1998 projections, are actuals for the first three quarters and forecasted for the fourth quarter rather than actual for the first quarter and forecasted for the final three quarters. The combination of these two changes caused a reduction to the residential forecast presented in my Direct Testimony of approximately 11,500 mWh.

Q. DOES THE ESTIMATED ECONOMETRIC EQUATION SHOWN IN SCHEDULE___(SLE-1) INCORPORATE THE UPDATED DATA?

A. No. The estimated equation relies on historical data through the first quarter of 1997. The updated data only affect the projections of sales in the forecast period through the operation of the lagged variables and also through the projections of the number of residential customers. The number of residential customers are assumed to grow at a rate of 0.9 percent per year and the growth rate is applied to the year-to-year quarterly values. Because actual values were available for the second and third quarters of 1997, which differed slightly from the previously projected values, the projections of the number of customers in the second and third quarters of the rate year differ slightly from the number originally projected.

Q. WERE ANY OTHER CHANGES TO THE RESIDENTIAL SALES MODEL OCCASIONED BY THIS UPDATE?

A. Yes. In the forecast of sales presented in my direct testimony, a downward adjustment was made to eliminate a potential overforecasting problem associated with a high level of recorded sales in the third quarter of 1996. Specifically, the lag structure of the model, through the lagged dependent variable, would have carried a portion of the higher usage level through to the third quarter of each year of the forecast period. With reliance on third quarter actuals for 1997, that adjustment became unnecessary and was eliminated.

Q. HAVE YOU COMPUTED CONFIDENCE INTERVALS FOR YOUR RESIDENTIAL SALES FORECAST?

A. Yes, though subject to the same qualifications as noted in my Direct Testimony, that is, the confidence intervals relate only to innovation uncertainty and do not include any uncertainty associated with the parameter estimates. At a 95 percent confidence interval, the residential sales forecast of 553,700 mWh is bounded on the high side and low side by 587,000 mWh and 522,300 mWh, respectively.

__General Issues__

Q. IN DR. CRINER'S REBUTTAL TESTIMONY AT PAGE 12, HE STATES THAT HE BELIEVES THAT YOU CONTINUE TO RE-ESTIMATE YOUR MODELS UNTIL YOU SATISFY PRE-SET CONDITIONS. IS THIS ASSESSMENT ACCURATE?

A. Yes. I typically make multiple estimations, using information regarding the relationships among the regressors obtained from these estimations to refine the equation. In so doing, estimation results are evaluated using a "set of conditions," which, if violated, result in rejection of the estimation. The conditions include, but are not limited to, conformance with economic theory, reasonable magnitudes for the parameters (e.g., reasonable elasticities), and freedom from serious statistical problems, such as autocorrelation. While this approach is problematic for hypothesis testing, there is no satisfactory alternative for developing useful forecasting equations. At page 65 of his rebuttal testimony, Mr. Cooper appears to concur, stating: "starting in 1994, I began experimenting with different price formulations for commercial and residential sales."

Q. DR. CRINER SUGGESTS THAT YOU ESTIMATED YOUR EQUATIONS WITH SEPARATE HDD AND CDD VARIABLES AND USED A COMPOSITE DEGREE DAY VARIABLE WHEN THE SEPARATE VARIABLES DID NOT MEET YOUR CRITERIA. IS THAT CORRECT?

A. No. No equations were estimated using separate CDD and HDD regressors.

Q. MR. COOPER INDICATES THAT THE FORECAST CONTAINED IN YOUR DIRECT TESTIMONY IMPLIES A RATE OF GROWTH IN EXCESS OF WHAT OTHER FORECASTERS ARE PREDICTING AND UNLIKELY TO BE ACHIEVED BY BHE WITHIN THE RELEVANT FORECAST PERIOD. PLEASE COMMENT.

A. Given the year-to-date sales recorded by BHE, I must concur with Mr. Cooper's assessment regarding the likelihood of achieving the sales levels projected in my Direct Testimony. With respect to compatibility with other forecasts such as those produced by the Energy Information Administration, NERC, and NEPOOL, the forecast contained in my Direct Testimony was well above the more aggregate projections. The revised projections contained herein are substantially lower and reasonably consistent with the more aggregate figures. It should be noted, however, that localized conditions, weather factors, and other service area-specific factors can cause small area, short-term projections to differ significantly from longer-term, aggregate regional projections.

Mr. Cooper's Residential Model

Q. MR. COOPER INDICATED IN HIS DIRECT TESTIMONY THAT HIS RESIDENTIAL WEATHER NORMALIZATION EQUATION HAS AN OMITTED VARIABLE, MAKING IT UNSUITABLE FOR USE IN ECONOMETRIC FORECASTING. IN HIS REBUTTAL TESTIMONY, HE STATES THAT THE OMITTED VARIABLE, WHICH HE ASSERTS IS RELATED TO THE ACCUMULATED EFFECTS FROM FEDERAL APPLIANCE EFFICIENCY STANDARDS, DOES NOT INTRODUCE BIAS BECAUSE APPLIANCE EFFICIENCY STANDARDS ARE NOT CORRELATED WITH DEGREE DAYS, INCOME, OR PRICE. PLEASE COMMENT.

A. Mr. Cooper's logic on this issue is faulty. Federal appliance efficiency standards, while correctly characterized as uncorrelated with other variables included in his model, will result in reductions in residential consumption only through the purchase of appliances complying with the standards. As new appliances embodying the standards are introduced, the average appliance efficiency of the appliance stock will increase. The introduction of new appliances embodying the federal standards is not only correlated with factors such as income and the price of electricity, it is dependent on those factors.

Q. IN YOUR DIRECT TESTIMONY, YOU INDICATED THAT MR. COOPER'S MODEL WAS MISSPECIFIED DUE, IN PART, TO THE RESTRICTION THAT CONSUMER RESPONSE TO A CHANGE IN INCOME IS WHOLLY COMPLETED IN THE CONTEMPORANEOUS CALENDAR QUARTER. MR. COOPER INDICATES THAT THIS IS NOT A PROBLEM DUE TO EITHER THE RATIONAL EXPECTATIONS HYPOTHESIS, THE ADAPTIVE EXPECTATIONS HYPOTHESIS, OR BOTH. PLEASE COMMENT.

A. Several observations here are warranted. First, this argument takes the cast of an ex post rationalization, albeit creative, for a recognized modeling deficiency. This aside, it should be evaluated on its merits.

With respect to the rational expectations hypothesis, one should note that this is not a universally accepted notion. It is generally applied to issues related to Federal Reserve policy, and I am unfamiliar with any sectoral consumption analyses that rely on this as an underpinning. Further, it is unclear why, if Mr. Cooper subscribes to the rational expectations hypothesis, that it would only apply to income and not to price.

This last point has equal validity for the adaptive expectations hypothesis. Furthermore, if individuals only react to long-term trends, there is no need to include income and price as variables. A simple time trend would suffice. This, however, is contradicted by a large body of empirical evidence which shows that consumers do react to changes in factors such as income and price and these factors do affect electricity consumption. Consequently, reliance on these hypotheses to explain the adequacy of full contemporaneous consumer response to changes in income is inconsistent with the specification of the price variable and, taken to its logical extreme, inconsistent with the specification of a causal model.

Commercial/Industrial Sales

Q. YOU NOTED PREVIOUSLY IN THIS SURREBUTTAL TESTIMONY THAT THE STAFF IS PREPARED TO ADOPT THE COMPANY'S PROJECTION OF COMMERCIAL/INDUSTRIAL SALES FOR THE RATE YEAR. PLEASE EXPLAIN.

A. In the Company's Rebuttal Testimony presented by Mr. Cooper and Dr. Criner, several issues emerged with respect to the commercial/industrial model presented in my Direct Testimony. Two of the issues identified by the Company witnesses were both valid and potentially important. These were the change in revenue responsibility between large and small commercial/industrial customers that occurred in the mid-1980s discussed by Mr. Cooper and an apparent trend in the pattern of residuals toward the end of the historical estimation period. These two factors, coupled with the model's over forecasting of actual sales that have become available since the model was developed, strongly suggested revision to the model be made.

Correcting for the important and meaningful problems resulted in other problems being created, such as theoretically implausible parameter estimates, e.g., parameter estimates suggesting excessively rapid adjustment to changes in long-run causal factors such as price. Because a satisfactory causal model could not be developed, reliance on the Company's time-trend approach was viewed as a reasonable second best alternative.

Q. DOES YOUR ADOPTION OF THE COMPANY'S COMMERCIAL/INDUSTRIAL MODEL INCLUDE ADOPTION OF THE COMPANY'S DOWNWARD ADJUSTMENT TO TIME-TRENDED SALES TO ACCOUNT FOR CHANGES IN EFFICIENCY STANDARDS RELATED TO LIGHTING?

A. Yes. In my Direct Testimony, I stated that explicit incorporation of an adjustment to reduce sales due to lighting efficiency standards introduces a potential to double-count the reduction to sales since at least some degree of the expected reduction is implicitly contained in the time trend. Further review and consideration of this issue suggests that while a portion of the impact is likely to be captured by the time trend, the full impact will not be captured given the relatively recent vintage of the lighting requirements. Mr. Cooper relied on a 50 percent adjustment phased in over five years. The 50 percent figure is likely to be more accurate than no adjustment and certainly more accurate and reasonable than a 100 percent adjustment.

Q. DOES YOUR ADOPTION OF THE COMPANY'S COMMERCIAL/INDUSTRIAL FORECAST INDICATE BLANKET AGREEMENT WITH THE COMPANY'S APPROACH?

A. No. The issues expressed in my Direct Testimony and this Surrebuttal Testimony remain. If a reasonable and appropriate causal model of commercial/industrial sales could have been developed given the available data, my recommendation would be for adoption of that model.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

RE:	BANGOR HYDRO-ELECTRIC COMPANY PROPOSED INCREASE IN RATES	)))	DOCKET NO. 97-116

EXHIBITS ACCOMPANYING THE

SURREBUTTAL TESTIMONY

OF

STEVEN L. ESTOMIN, PH.D.

ON BEHALF OF THE

MAINE PUBLIC UTILITIES COMMISSION STAFF

OCTOBER 1997

EXETER

Associates, Inc.

12510 Prosperity Drive
Suite 350
Silver Spring, MD 20904

BANGOR HYDRO-ELECTRIC COMPANY

Residential Sales Equation

$$\ln(SALES_t/CUST_t) = -0.366298 + 0.846470 \ln(SALES_{t-4}/CUST_{t-4}) - 0.056524 \ln(PRICE_t)$$
$$- 0.009140 \ln(PRICEA_t) + 0.117497 \ln(INCOME_t) + 0.059278\ WEATHER$$
$$+ 0.030397\ D1 - 0.075769\ D863 + 0.104956\ D853$$

Regressor	Estimated Parameter	Standard Error	t-Statistic
Constant	-0.366298	0.428	-0.856
$SALES_{t-4}/CUST_{t-4}$	0.846470	0.068	12.488
$PRICE_t$	-0.056524	0.045	-1.259
$PRICEA_t$	-0.009140	0.004	-2.337
$INCOME_t$	0.117497	0.049	2.401
$WEATHER_t$	0.059278	0.018	3.380
D1	0.030397	0.015	2.009
D863	-0.075769	0.027	-2.836
D853	0.104956	0.027	3.910

R-squared	0.970
Adjusted R-squared	0.966
S.E. of regression	0.025
Sum of squared residuals	0.035
F-Statistic	230.206
Estimation period	1981, Q1 to 1997, Q1
Number of observations	65
Iterations	8

BANGOR HYDRO-ELECTRIC COMPANY

Residential Sales Equation

Definition of Variables

$SALES_t/CUST_t$	=	Average monthly residential kWh sales (adjusted for DSM) over the calendar quarter divided by the average number of residential customers.
CONSTANT	=	Constant term.
$SALES_{t-4}/CUST_{t-4}$	=	Average monthly residential kWh sales (adjusted for DSM) over the same calendar quarter of the prior year divided by the average number of customers in the same quarter of the prior year.
$PRICE_t$	=	The residential price of 500 kWh per month deflated to real terms using the Consumer Price Index.
$PRICEA_t$	=	$PRICE_t$ for the period 1982Q1 through 1986Q4 and zero elsewhere.
$INCOME_t$	=	Maine real per capita personal income.
D1	=	A binary dummy variable set equal to 1 in the first quarter of each year and zero elsewhere.
D863	=	A binary dummy variable set equal to 1 in the third quarter of 1986 and zero elsewhere.
D853	=	A binary dummy variable set equal to 1 in the third quarter of 1985 and zero elsewhere.
$WEATHER_t$	=	$\ln (HDD_t + 2(CDD_t)) - 0.847265 \ln (HDD_{t-4} + 2(CDD_{t-4}))$

where:

HDD_t	=	heating degree days for the quarter, lagged one month;
CDD_t	=	cooling degree days for the quarter, lagged one month;
HDD_{t-4}	=	heating degree days for the same quarter of the prior year, lagged one month; and
CDD_{t-4}	=	cooling degree days for the same quarter of the prior year, lagged one month.

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE TO
WESTERN KENTUCKY GAS CO. DATA REQUESTS
SET I

22. Provide workpapers and source documents utilized in the preparation of Exhibit SLE-1.

Response

No work papers other than the data and computer output contained in Exhibit___SLE-1 attached to Dr. Estomin's Direct Testimony were utilized.

Responsible Witness: Steven L. Estomin

Q. PLEASE DESCRIBE YOUR FORECAST RESULTS.

A. Sales to commercial/industrial customers, excluding the paper mills and HoltraChem, for the twelve months ending February 1999 are projected to be 715,122 mWh, which is 30,361 mWh higher than the Company's projection of 684,761 mWh over the same period. The Staff's forecast of commercial/industrial sales indicates an average annual growth rate of 2.87 percent over commercial/industrial sales made in calendar year 1996 compared to the Company's forecasted average annual growth rate of 0.8 percent over the same period.

V. OTHER SALES

Q. WHAT ADDITIONAL CATEGORIES OF SALES HAVE BEEN FORECASTED FOR THE RATE YEAR BY BHE?

A. In addition to residential, commercial, and industrial sales, BHE also forecasted sales to the paper mills served by the Company, HoltraChem (a large industrial user), lighting, and wholesale sales.

Q. HAVE YOU MADE ALTERNATIVE FORECASTS OF SALES TO THESE CUSTOMERS?

A. No. The Company's forecasts of sales to these categories of customers appear to be reasonable and are based on recent historical sales levels adjusted, as warranted, for known and anticipated changes. The Staff has adopted BHE's forecasts for these sales categories and has included these projections into its overall sales projection.

VI. CONFIDENCE INTERVALS

Q. PLEASE EXPLAIN THE MAIN SOURCES OF ERROR ASSOCIATED WITH ECONOMETRIC FORECASTING.

A. There are four principal sources of error. These are:

1. Error associated with the parameter estimates (coefficient uncertainty);
2. Error related to the specification of the model;
3. Random disturbance error (innovation uncertainty); and
4. Errors in the projections of the causal variables, or regressors.

Forecast error related to parameter estimates is generally quantifiable, as is the error associated with random disturbance. Error related to specification is not quantifiable but is minimized by careful development of the model to ensure consistency with established theory. Errors in the projected regressors are unquantifiable as well. Of these, the most important sources of error involve innovation uncertainty.

Q. HAVE YOU COMPUTED CONFIDENCE INTERVALS FOR YOUR FORECASTS OF RESIDENTIAL AND COMMERCIAL SALES?

A. Yes. The confidence intervals developed and shown below, however, relate only to the random disturbance term (i.e., innovation uncertainty) . Because the equations estimated for the residential and commercial/industrial sectors are parametrically non-linear, calculation of confidence intervals associated with the parameter estimates is extremely difficult and may be unfruitful.

The confidence intervals shown are based on a 5 percent level of significance which is computed using plus and minus 1.96 standard deviations around the mean.

95 Percent Confidence Intervals for the Residential and Commercial/Industrial Sales Projections (mWh)	Lower Bound	Forecast	Upper Bound
Residential	529,526	565,205	603,179
Commercial/Industrial	662,083	715,122	772,305

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
THE APPLICATION OF WESTERN	)	Case No. 99-070
KENTUCKY GAS COMPANY	)	
FOR AN ADJUSTMENT OF RATES	)	

ATTORNEY GENERAL'S RESPONSE
TO THE DATA REQUEST OF THE
PUBLIC SERVICE COMMISSION

Comes now the Attorney General, through his Office of Rate Intervention, and submits his Response to the data request of the Public Service Commission.

Respectfully submitted,

A.B. CHANDLER III
ATTORNEY GENERAL

David Edward Spenard

David Edward Spenard
Assistant Attorney General
1024 Capital Center Drive
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CERTIFICATE OF SERVICE AND FILING

Counsel certifies that an original and fifteen (15) photocopies of the foregoing Attorney General's Response to the Data Request of the Public Service Commission were served and filed by hand delivery to the Hon. Helen C. Helton, Executive Director, Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to William J. Senter, Western Kentucky Gas, 2401 New Hartford Road, Owensboro, KY 42303 1312, Mark R. Hutchinson, Sheffer, Hutchinson & Kinney, 115 East Second Street, Owensboro, KY 42303, John N. Hughes, 124 West Todd Street, Frankfort, KY 40601, Douglas Walther, Atmos Energy Corporation, P.O. Box 650205, Dallas, TX 75265, Keith Tiggelaar, WBI Southern, Inc., P.O. Box 5601, Bixmark, ND 58506 5601, and Robert M. Watt, Jr., J. Mel Camenisch, Jr., 201 E. Main Street, Suite 1000, Lexington, KY 40507-1380, all on this 22nd day of November 1999.

David Edward Spenard
Assistant Attorney General

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WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

1. Refer to page 5 of the Direct Testimony of Lafayette K. Morgan. Concerning the proposed adjustments to the plant in service:

   a. Explain how Mr. Morgan determined his completion percentage of 92 percent. Include all supporting calculations.

   b. Explain how Mr. Morgan determined his 39.5 percent overhead factor. Include all supporting calculations and provide the citations to the appropriate data responses.

   c. In excluding structures and improvements from plant in service, explain whether Mr. Morgan contends such an adjustment is inappropriate, or whether he takes issue with the approach proposed by Western. Explain the response.

Response

a. The 92 percent completion ratio is based upon the rates of actual completed capital expenditures and budgeted capital expenditures. Both are based upon the 1994 to 1998 fiscal years. See Attachment A.

b. The 39.5 percent ratio is the average overhead factor for 1996 to 1999 fiscal years. See Attachment B.

c. The disagreement is over the method used by Western. Western used a baseline approach in developing the future test year budget. As a result, the future test already included expenditures for structures and improvement. Western also

Responsible Witness: Lafayette K. Morgan, Jr.

Response 1 cont'd

added another layer of structures and improvement expenditures based upon the use of a 36.25 percent factor. The extra layer (based on the 36.25 percent factor) is the level of expenditures that I have removed. Western has not provided any data that show that the additional expenditures are not covered by the "baseline" expenditures. Therefore those expenditures were considered to be unsupported.

Responsible Witness: Lafayette K. Morgan, Jr.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 190
Witness: David H. Doggette

Data Request:

190. With reference to the discussion in Mr. Doggette's testimony relative to the control and monitoring of capital expenditures:

a. Please explain whether the spending on any capital projects is affected when other capital projects exceed their approved funding levels. If so, please explain fully how spending on capital projects is interrelated.

b. In instances where projects are delayed during a given fiscal year, are the approved funds available for use on other projects? If so, is there is a separate approval process for the shifting of funds? Please explain.

c. Please explain the decrease in the capital budget between FY 1997 and FY 1998.

Response:

a. Western manages the capital budget on a project basis. However, the capital budget is developed beforehand when all particulars of a project may not be known. Western also works towards managing within the overall fiscal year capital budget.

b. When projects are delayed, they must be budgeted again in the fiscal year in which they are anticipated to occur. If it is deemed prudent to utilize capital funds for other projects, those projects are submitted through the approval process.

c. It should be noted at this point that a revision to the table shown on page 8 of the testimony of David H. Doggette is necessary. The capital budget amounts shown for the 1994-1997 fiscal years include overheads. The amounts stated for 1998 do not include the applicable overhead amounts. The table is revised and restated to show overheads included for all years on Schedule AG DR1 190 attached.

The FY 1997 to FY 1998 decrease in capital budget is related to non-recurring projects, highway relocation projects, computer purchases, vehicle purchases, and reduced non-direct charges. Refer to page 8 of the testimony of David H. Doggette. Also refer to KPSC DR1-28, pages 18 through 28 and AG IDR 225.

SCHEDULE AG DR1-190

Revised - Western's Historical Capital Expenditures

Fiscal Year	Actual Dollars	Budgeted Dollars	Over/(Under) Budget, $'s	Variance (%)
1998	$ 11,459,605	$ 10,194,434	$ 1,265,171	12.4%
1997	$ 15,085,222	$ 16,595,351	$ (1,510,129)	-9.1%
1996	$ 14,253,519	$ 17,770,374	$ (3,516,855)	-19.8%
1995	$ 15,458,055	$ 16,592,170	$ (1,134,115)	-6.8%
1994	$ 10,872,491	$ 11,453,427	$ (580,936)	-5.1%

67,128,892

72,605,756

.92

Total Actual $ 1994 - 1998 67,128,892 = .92
Total Budgeted $ 1994 - 1998 72,605,756

Attachment B

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 21
Witness: David H. Doggette

Data Request:

21. With reference to the response to KPSC 1-10, an explanation is given for the 50 percent overhead rate. Please provide similar data for FY 1996 through 1998.

Response:

The overhead percent and allocation amounts for 1996 through 1998 are shown. Although overhead percentage has increased each year, the total for the allocation amount combined with capital budget have been reduced each year.

	Fiscal Year 1996	Fiscal Year 1997	Fiscal Year 1998
Total Capital Budget	$17,770,374	$16,595,351	$10,194,434
Atmos A & G	$2,665,556	$2,987,163	$1,631,109
Western	$2,843,269	$2,655,256	$2,446,664
Total Allocation	$5,508,825	$5,642,419	$4,077,773
Percent Overhead	31%	34%	40%

FY 96 31%
FY 97 34%
FY 98 40%
FY 99 53% (from response to KPSC 1-10)
158 ÷ 4 = 39.5%

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

2. Western has indicated that the approach used to develop the capital budgets submitted in its application with the approach normally used for preparation of its budgets.

   a. Has Mr. Morgan examined or reviewed the differences between Western's "bottom up" approach, which was normally used for capital budgeting, and the "baseline" forecast approach used in this application? If yes, what were the results of Mr. Morgan's examination?

   b. Does Mr. Morgan have any concerns about Western's use of the "baseline" rather than "bottom up" approach for its capital budgeting in this proceeding? Explain the response.

<u>Response</u>

a. No. Western indicated it did not have a "bottom up" budget.

b. Since Western used a baseline approach in developing its capital budget for the forecast period, the concerns were related to the escalation factors. I have addressed those areas that were of concern on pages 5 and 6 of my testimony. Specifically, the overhead rate, the structures and improvement factor and the completion ratio were of concern. The other concern was the inflation factor. However, Western's derivation of the inflation factor appears reasonable.

<u>Responsible Witness</u>: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

3. Refer to page 9 of Mr. Morgan's Direct Testimony. Over what time period was Western's frequency of filing rate cases averaged to derive the average of four years for amortization of rate case expense?

Response

Based upon the Orders in my possession, the following is derivation of the frequency of rate cases:

Case No.	Filed Date	Time Span (Years)
8227	April 1981	
8839	June 1983	2
9556	May 1986	3
90-013	February 1990	4
95-010	February 1995 (assumed)	5
	Average	3.5 years
	Used	4 years

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

4. Refer to pages 9 and 10 of Mr. Morgan's Direct Testimony.

   a. In recommending uncollectible expense based upon the average of the latest five-year period, was any consideration given to whether Western might have an upward trend in uncollectibles over recent years?

   b. When determining the proposed adjustment for uncollectible expense, was Mr. Morgan aware that Western's response to Item 40 of the Commission's July 16, 1999 Order shows actual uncollectibles increasing from $171,000 for FY 1995 to $706,443 for FY 1998? Would this trend affect Mr. Morgan's recommendation? Explain the answer in detail.

Response

a. & b. Consideration was given to whether there may be an upward trend in uncollectible. However, the response to KPSC 1-40 would not affect my recommendation because there also is the possibility that uncollectibles could decrease. It is not uncommon to find uncollectibles fluctuating from one year to the next. In responses to data requests, Western could not provide an explanation which would support a continued increase in uncollectibles. As a result, the average was used to normalize the uncollectibles due to the fact that uncollectibles fluctuate. Normalization also provides an incentive for the Company to minimize uncollectibles.

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

5. Refer to page 10 of Mr. Morgan's Direct Testimony.

a. Is it Mr. Morgan's contention that lawsuit settlement costs are brought about because of management, and therefore should be borne by the shareholders? Explain the answer in detail.

b. Is it Mr. Morgan's opinion that to the extent that lawsuit settlement costs are recovered by operating earnings in the year the costs are incurred, deferral and amortization to future years is not appropriate? Explain the answer in detail.

Response

a. No.

b. Yes. To the extent that lawsuit settlement cost (and all other costs) are incurred in a given period, it is assumed to be recovered through rates collected from customers. Rates are generally considered just and reasonable until changed by the Commission. A company has the right to seek authority from the Commission to defer costs for future recovery when it believes a given cost may imposed a financial hardship for the Company to absorb. Western's decision to amortize these costs is based upon its policy to amortize any lawsuit settlement cost in excess of $50,000 over a five-year period.

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
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6. Refer to pages 10 and 11 of Mr. Morgan's Direct Testimony. Would Mr. Morgan agree that if Western demonstrates direct benefits to its customers derived from the merger, then some portion of the merger and acquisition costs may be appropriately charged to its ratepayers? Explain the answer in detail.

Response

No. The costs that I am recommending to be removed from O&M expenses are costs that the Company has identified as costs be borne by Shareholders. I believe it is proper for shareholders bear some responsibility for merger costs.

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
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ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

7. Refer to pages 13-16 of Mr. Morgan's Direct Testimony. Based on the testimony and the computation on Schedule LKM-14, Mr. Morgan proposes an adjustment to reduce operations and maintenance expense by $2,272,501 reflecting pension expense at the 1999 actuarial level according to FASB Statement No. 87. Explain the rationale for this adjustment in consideration of the Testimony of Donald P. Burman, at pages 6 and 7, Volume 2 of 10, of Western's Application, which states that "Western's pension assets are held in trust for the benefit of Western's employees."

Response

The rationale for the adjustment is to reflect the most recent pension expense based upon SFAS 87. The amount used was derived from the Company's actuaries. The fact that the pension assets are held in trust is not affected by this adjustment. Because of the funding status of the pension plan the Company will not be contributing to the pension trust fund regardless of whether pension expense is set at the SFAS 87 level or at $0, which the Company is proposing. Adoption of my adjustment does not require moving funds in or out of the pension trust fund.

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
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ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

8. Refer to page 16 of Mr. Morgan's Direct Testimony.

   a. Cite when during the base period the actual level of employees of 258 used to compute Mr. Morgan's adjustment for payroll expenses occurred and where in the record this data is located.

   b. If Western increases its number of employees for the actual base period that ended September 30, 1999, would Mr. Morgan increase the level of employees for the forecasted year? Explain the answer in detail.

Response

a. Actual level of employees of 258 is level of employees at September 30, 1999.

   See the response to AG Supplemental Data Request No. 26.

b. The trend in employee levels is also an important factor as well as the Company's plans. For example, a sharp increase from one month to the next would have to be investigated.

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
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SET I

9. Mr. Morgan's Direct Testimony addresses Western's operating results based on the forecasted test year ending December 31, 2000. Mr. Morgan's testimony does not address Western's proposed adjustments for (1) customer growth or (2) declining usage per customer.

   a. Explain whether Mr. Morgan's analysis included a review of these two adjustments.

   b. Provide a detailed description of the extent of Mr. Morgan's analysis of these two adjustments.

   c. Assuming that the absence of any discussion of these adjustments reflects Mr. Morgan's acceptance thereof, explain how Mr. Morgan's analysis led him to accept those adjustments.

<u>Response</u>

a. b. and c.

Mr. Morgan's analysis included a review of the two adjustments. The analysis included a review of the data contained in the Company's filing as well as its responses to data requests. Based on recent sales trends and forecasted sales level, Western's sales level was not considered unreasonable.

<u>Responsible Witness</u>: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY
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10. Refer to page 18 of Mr. Morgan's Direct Testimony. Concerning the demand side management ("DSM") cost recovery proposal:

a. Prior to the filing of Mr. Morgan's testimony, indicate where in the record of this proceeding the AG has taken the position that the past DSM costs are not eligible for recovery and should not be allowed as part of any DSM surcharge arising out of this proceeding.

b. Explain why Mr. Morgan and the AG have not expressed a position on a prospective DSM charge and why it is appropriate to address this issue only in the AG's post-hearing brief.

Response

a. Prior to his pre-filed testimony, the Office of Attorney General told Mr. Morgan of its position that the past DSM costs are not eligible for recovery. The basis for this position is an interpretation of the applicable law. Hence, Mr. Morgan's testimony reflects this position. Prior to the testimony, the position was not a matter of record in this proceeding.

b. The Attorney General has chosen to decline taking a position on the prospective DSM charge until the record in this case is complete. The Attorney General wants to see, and give consideration to, any additional evidence relating to this item that may develop at a public hearing. Thus, the post-hearing brief is the most appropriate time for addressing this issue.

WESTERN KENTUCKY GAS COMPANY
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SET I

11. Refer to Schedule LKM-5 of Mr. Morgan's Direct Testimony.

a. Provide the calculations referenced in Note No. 1 on this schedule. Include citations to the specific data responses used in these calculations.

b. Explain in detail how Mr. Morgan recognized the plant in service additions during the forecasted period. Include a discussion of how Mr. Morgan's approach to recognizing the additions compares with that proposed by Western. Also explain why Mr. Morgan's approach is reasonable.

Response

a. See the attached workpapers.

b. The approach taken by Mr. Morgan is similar to the method used by Western.

The primary areas of differences are the issues discussed on pages 5 and 6 of his testimony.

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY

Calculation of FY1999 Plant Expenditures
For the Test Year Ending December 31, 2000

EXHIBIT DHD-1

KPSC 1-35a

Description	Acct No.	Amount Per Company	92% of Budget	Projects	Inflation	Direct Costs	O/H (58.63%)	98 O/H Carryover	Total
MIS									
Office Equipment	399.0000		0			0	0		0
PC Hardware	399.8600	35,980	33,102			33,102	19,409	5,757	58,268
PC Software	399.8700	10,000	9,200			9,200	5,394	1,600	16,194
Application Software	399.8800		0			0	0		0
		45,980	42,302			42,302	24,803	7,357	74,462
Equipment									
Other Equipment	384.0000	2,250	2,070			2,070	1,214	360	3,644
Structures & Improvement	390.0000		0			0	0		0
Air Conditioning	390.0300		0			0	0		0
Improved s- Leased Premises	390.0900	10,000	9,200			9,200	5,394	1,600	16,194
Office Furniture	391.8300		0			0	0		0
Office Machines	391.0000	1,500	1,380			1,380	809	240	2,429
Tools, Shop & Equipment	394.7700	4,000	3,680			3,680	2,158	640	6,478
Communications Telephones	397.0000	40,000	36,800			36,800	21,577	6,400	64,777
Communications- Mobile Radio	397.2000	6,000	5,520			5,520	3,237	960	9,717
		63,750	58,650			58,650	34,389	10,200	103,239
System Maintenance									
Transmission - Leakage	367.0000	29,750	27,370			27,370	16,048		43,418
Steel Mains - Leakage	376.0000	294,780	271,198			271,198	159,010	44,314	648,346
Plastic Mains- Leakage	376.0000	154,308	141,963			141,963	83,236	23,197	339,387
Services - Leakage	380.0000	330,770	304,308			304,308	178,423	59,008	740,186
Meter Loops - Leakage	382.0000	5,000	4,600			4,600	2,697	876	11,167
Retirements		319,480	293,922			293,922	172,334		0
		1,134,088	1,043,361			1,043,361	611,748	127,395	1,782,504
System Improvements									
Field Lines	353.1000	25,512	23,471			23,471	13,762		37,233
Gathering Lines	353.2000	5,962	5,485			5,485	3,216		8,701
Transmission Mains - Cathodic Prc	367.0000	3,037	2,794			2,794	1,638		4,432
Transmission Mains - System Impr	367.0000	9,476	8,718			8,718	5,112		13,830
Measurements & Regulation Statio	369.1000	5,959	5,482			5,482	3,214		8,696
Mains - Cathodic Protection	376.0000	71,500	65,780			65,780	38,568	10,748	94,239
Mapping Conversion	376.0000	100,000	92,000			92,000	53,942	15,033	131,803
Steel System Improvement	376.0000	361,230	332,332			332,332	194,854	54,303	476,113
Plastic System Improvements	376.0000	34,275	31,533			31,533	18,489	5,153	45,176
Measurements & Regulation SYs. I	378.0000	136,000	125,120			125,120	73,361	22,232	180,716
Measurements & Regulation - Equi	379.0000	23,500	21,620			21,620	12,676	3,781	31,177
Meter Loops - System Improvemer	382.0000	127,463	117,266			117,266	68,756	22,337	170,600
Industrial Measurement & Regulati	385.0000	98,000	90,160			90,160	52,863	11,904	126,851
Public Works Reimbursements		(190,579)	(175,333)			(175,333)	(102,802)		0
		811,335	746,428			746,428	437,649	145,491	1,329,568
Growth									
Forfeitures	376.0000	(381,919)	(351,365)			(351,365)	(206,014)		(557,379)
Steel Revenues Mains	376.0000	83,705	77,009			77,009	45,152	12,583	134,744
Plastic Revenue Mains	376.0000	1,353,647	1,245,355			1,245,355	730,182	203,491	2,179,028
Measurements& Regulation - Reve	378.0000	11,290	10,387			10,387	6,090	1,846	18,323
Measurements& Regulation - City	379.0000	66,000	60,720			60,720	35,602	10,619	106,941
Services - Revenues	380.0000	1,386,012	1,275,131			1,275,131	747,641	247,259	2,270,031
Meters - Revenues	381.0000	480,431	441,997			441,997	259,154	78,112	779,263
Meter Loops - Revenues	382.0000	300,949	276,873			276,873	162,337	52,738	491,948
House Regulators - Revenues	383.0000	106,534	98,011			98,011	57,468	17,061	172,538
Industrial Measurement & regulatic	385.0000		0			0	0		0
		3,406,649	3,134,118			3,134,118	1,837,610	623,710	5,595,438
Total		5,461,802	5,024,859			5,024,859	2,946,199	914,152	8,885,210

WESTERN KENTUCKY GAS COMPANY

Calculation of FY2000 Plant Expenditures
For the Test Year Ending December 31, 2000

DHD-1

Description	Acct No.	Amount Per Company	92% of Budget	Projects	Inflation 3.00%	Direct Costs	O/H 39.50%	Total
MIS								
Office Equipment	399.0000		0	0	0	0	0	0
PC Hardware	399.8600	35,980	33,102	0	993	34,095	13,468	47,563
PC Software	399.8700	10,000	9,200	0	276	9,476	3,743	13,219
Application Software	399.8800		0	0	0	0	0	0
		45,980	42,302	0	1,269	43,571	17,211	60,782
Equipment								
Other Equipment	384.0000	2,250	2,070	0	62	2,132	842	2,974
Structures & Improvement	390.0000		0	0	0	0	0	0
Air Conditioning	390.0300		0	0	0	0	0	0
Improved s- Leased Premises	390.0900	10,000	9,200	0	276	9,476	3,743	13,219
Office Furniture	391.8300		0	0	0	0	0	0
Office Machines	391.0000	1,500	1,380	0	41	1,421	561	1,982
Tools, Shop & Equipment	394.7700	4,000	3,680	0	110	3,790	1,497	5,287
Communications Telephones	397.0000	40,000	36,800	0	1,104	37,904	14,972	52,876
Communications- Mobile Radio	397.2000	6,000	5,520	0	166	5,686	2,246	7,932
		63,750	58,650	0	1,759	60,409	23,862	84,271
System Maintenance								
Transmission - Leakage	367.0000	29,750	27,370	0	821	28,191	11,135	54,750
Steel Mains - Leakage	376.0000	294,780	271,198	0	8,136	279,334	110,337	542,496
Plastic Mains- Leakage	376.0000	154,308	141,963	0	4,259	146,222	57,758	283,978
Services - Leakage	380.0000	330,770	304,308	0	9,129	313,437	123,808	608,727
Meter Loops - Leakage	382.0000	5,000	4,600	0	138	4,738	1,872	9,202
Retirements		319,480	293,922	0	8,818	302,740	119,582	0
		1,134,088	1,043,361	0	31,301	1,074,662	424,491	1,499,153
System Improvements								
Field Lines	353.1000	25,512	23,471	0	704	24,175	9,549	27,309
Gathering Lines	353.2000	5,962	5,485	0	165	5,650	2,232	6,383
Transmission Mains - Cathodic Prc	367.0000	3,037	2,794	0	84	2,878	1,137	3,251
Transmission Mains - System Impr	367.0000	9,476	8,718	0	262	8,980	3,547	10,144
Measurements & Regulation Statio	369.1000	5,959	5,482	0	164	5,646	2,230	6,378
Mains - Cathodic Protection	376.0000	71,500	65,780	0	1,973	67,753	26,762	76,537
Mapping Conversion	376.0000	100,000	92,000	0	2,760	94,760	37,430	107,046
Steel System Improvement	376.0000	361,230	332,332	0	9,970	342,302	135,209	386,682
Plastic System Improvements	376.0000	34,275	31,533	0	946	32,479	12,829	36,690
Measurements & Regulation SYs. I	378.0000	136,000	125,120	0	3,754	128,874	50,905	145,583
Measurements & Regulation - Equi	379.0000	23,500	21,620	0	649	22,269	8,796	25,156
Meter Loops - System Improvemer	382.0000	127,463	117,266	0	3,518	120,784	47,710	136,444
Industrial Measurement & Regulati	385.0000	98,000	90,160	0	2,705	92,865	36,682	104,905
Public Works Reimbursements		(190,579)	(175,333)	0	(5,260)	(180,593)	(71,334)	(0)
		811,335	746,428	0	22,394	768,822	303,685	1,072,507
Growth								
Forfeitures	376.0000	(390,000)	(358,800)	0	(10,764)	(369,564)	(145,978)	(515,542)
Steel Revenues Mains	376.0000	83,705	77,009	0	2,310	79,319	31,331	110,650
Plastic Revenue Mains	376.0000	1,353,647	1,245,355	0	37,361	1,282,716	506,673	1,789,389
Measurements& Regulation - Reve	378.0000	11,290	10,387	0	312	10,699	4,226	14,925
Measurements& Regulation - City (	379.0000	66,000	60,720	0	1,822	62,542	24,704	87,246
Services - Revenues	380.0000	1,386,012	1,275,131	0	38,254	1,313,385	518,787	1,832,172
Meters - Revenues	381.0000	480,431	441,997	0	13,260	455,257	179,827	635,084
Meter Loops - Revenues	382.0000	300,949	276,873	0	8,306	285,179	112,646	397,825
House Regulators - Revenues	383.0000	106,534	98,011	0	2,940	100,951	39,876	140,827
Industrial Measurement & regulatic	385.0000		0	0	0	0	0	0
		3,398,568	3,126,683	0	93,801	3,220,484	1,272,091	4,492,575
Total		5,453,721	5,017,424	0	150,524	5,167,948	2,041,339	7,209,287

WESTERN KENTUCKY GAS COMPANY

Calculation of FY2001 Plant Expenditures
For the Test Year Ending December 31, 2000

Description	Acct No.	92% of Budget	Projects 0.00%	Inflation 3.00%	Direct Costs	O/H 39.50%	Total
MIS							
Office Equipment	399.0000	0	0	0	0	0	0
PC Hardware	399.8600	34,095	0	1,023	35,118	13,872	48,990
PC Software	399.8700	9,476	0	284	9,760	3,855	13,615
Application Software	399.8800	0	0	0	0	0	0
		43,571	0	1,307	44,878	17,727	62,605
Equipment							
Other Equipment	384.0000	2,132	0	64	2,196	867	3,063
Structures & Improvement	390.0000	0	0	0	0	0	0
Air Conditioning	390.0300	0	0	0	0	0	0
Improved s- Leased Premises	390.0900	9,476	0	284	9,760	3,855	13,615
Office Furniture	391.8300	0	0	0	0	0	0
Office Machines	391.0000	1,421	0	43	1,464	578	2,042
Tools, Shop & Equipment	394.7700	3,790	0	114	3,904	1,542	5,446
Communications Telephones	397.0000	37,904	0	1,137	39,041	15,421	54,462
Communications- Mobile Radio	397.2000	5,686	0	171	5,857	2,314	8,171
		60,409	0	1,813	62,222	24,578	86,800
System Maintenance							
Transmission - Leakage	367.0000	28,191	0	846	29,037	11,470	56,393
Steel Mains - Leakage	376.0000	279,334	0	8,380	287,714	113,647	558,771
Plastic Mains- Leakage	376.0000	146,222	0	4,387	150,609	59,491	292,498
Services - Leakage	380.0000	313,437	0	9,403	322,840	127,522	626,989
Meter Loops - Leakage	382.0000	4,738	0	142	4,880	1,928	9,477
Retirements		302,740	0	9,082	311,822	123,170	(0)
		1,074,662	0	32,240	1,106,902	437,226	1,544,128
System Improvements							
Field Lines	353.1000	24,175	0	725	24,900	9,836	28,128
Gathering Lines	353.2000	5,650	0	170	5,820	2,299	6,575
Transmission Mains - Cathodic Pro	367.0000	2,878	0	86	2,964	1,171	3,348
Transmission Mains - System Impr	367.0000	8,980	0	269	9,249	3,653	10,448
Measurements & Regulation Statio	369.1000	5,646	0	169	5,815	2,297	6,569
Mains - Cathodic Protection	376.0000	67,753	0	2,033	69,786	27,565	78,834
Mapping Conversion	376.0000	94,760	0	2,843	97,603	38,553	110,257
Steel System Improvement	376.0000	342,302	0	10,269	352,571	139,266	398,282
Plastic System Improvements	376.0000	32,479	0	974	33,453	13,214	37,790
Measurements & Regulation Sys.. I	378.0000	128,874	0	3,866	132,740	52,432	149,950
Measurements & Regulation - Equi	379.0000	22,269	0	668	22,937	9,060	25,911
Meter Loops - System Improvemen	382.0000	120,784	0	3,624	124,408	49,141	140,537
Industrial Measurement & Regulati	385.0000	92,865	0	2,786	95,651	37,782	108,052
Public Works Reimbursements		(180,593)	0	(5,418)	(186,011)	(73,474)	(0)
		768,822	0	23,064	791,886	312,795	1,104,681
Growth							
Forfeitures	376.0000	(369,564)	0	(11,087)	(380,651)	(150,357)	(531,008)
Steel Revenues Mains	376.0000	79,319	0	2,380	81,699	32,271	113,970
Plastic Revenue Mains	376.0000	1,282,716	0	38,481	1,321,197	521,873	1,843,070
Measurements& Regulation - Reve	378.0000	10,699	0	321	11,020	4,353	15,373
Measurements& Regulation - City (	379.0000	62,542	0	1,876	64,418	25,445	89,863
Services - Revenues	380.0000	1,313,385	0	39,402	1,352,787	534,351	1,887,138
Meters - Revenues	381.0000	455,257	0	13,658	468,915	185,221	654,136
Meter Loops - Revenues	382.0000	285,179	0	8,555	293,734	116,025	409,759
House Regulators - Revenues	383.0000	100,951	0	3,029	103,980	41,072	145,052
Industrial Measurement & regulatio	385.0000	0	0	0	0	0	0
		3,220,484	0	96,615	3,317,099	1,310,254	4,627,353
Total		5,167,948	0	155,039	5,322,987	2,102,580	7,425,567

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WESTERN KENTUCKY GAS COMPANY

Calculation of December 31, 2000 Plant Balances
For the Test Year Ending December 31, 2000

WPB-2 B09

Description	Acct No.	Actual Mar. 99 Bal.	4/99 to 9/99 Additions	4/99 Serv Prog	9/99 Serv Prog	Plant Balance @9/99	FY2000 Additions	10/00-12/00 Additions
Intangible Plant								
Organization	301 0000	8,330				8,330		
Franchise & Consents	302 0000	119,853				119,853		
		128,183	0	0	0	128,183	0	0
Natural Gas Production								
Producing Leaseholds	325 2000	2,353				2,353		
Rights of Way	325 4000	6,069				6,069		
Production Gas Well Equip	331 0000	3,492				3,492		
Field Lines	332 1000	47,183				47,183		
Tributary Lines	332 2000	628,218				628,218		
Field Meas Stat Equip	334 0000	198,469				198,469		
Purification Equip.	336 0000	44,369				44,369		
		930,133	0	0	0	930,133	0	0
Storage Plant								
Land	350 1000	281,127				281,127		
Rights of Way	350 2000	4,682				4,682		
Compression Stat Equip	351 2000	121,265				121,265		
Meas & Reg Equip	351.3000	23,138				23,138		
Other Structures	351 4000	144,554				144,554		
Well Construction	352 0100	2,196,476				2,196,476		
Well Equip	352 0200	835,978				835,978		
Leaseholds	352 1000	178,530				178,530		
Storage Rights	352 1100	54,614				54,614		
Field Lines	353 1000	178,501	37,233			215,734	27,309	7,032
Tributary Lines	353 2000	209,458	8,701			218,159	6,383	1,844
Compression Stat Equip	354 0000	470,685				470,685		
Meas & Reg Equip	355 0000	288,851				288,851		
Purification Equip	356 0000	239,930				239,930		
		4,907,787	45,934	0	0	4,953,721	33,692	8,876
Transmission Plant								
Land	365 1000	29,951				29,951		
Rights of Way	365 2000	403,419				403,419		
Structures &Improv.	366 2000	14,797				14,797		
Other Structures	366 3000	69,172				69,172		
Mains	367 0000	19,283,669	30,840			19,314,509	68,145	17,547
Meas & Reg Equip	369 1000	2,948,291	8,696			2,956,987	6,378	
		22,749,299	39,536	0	0	22,788,835	74,523	17,547
Distribution Plant								
Land Town Border	374 1000	61,914				61,914		
Land Other	374 3000	2,784				2,784		
Right Of Way	374 2000	44,872				44,872		
Structure & Improvements T B	375 1000	106,376				106,376		
Structure & Improvements Other	375 0200	0				0		
Improvements	375 0300	7,518				7,518		
Land Rights	375 2000	46,591				46,591		
Mains	376 0000	69,297,505	1,745,729			71,043,234	2,817,926	293,341
Meas & Reg Sta Equip Gen.	378 1000	1,908,568	99,519			2,008,087	160,508	41,331
Meas & Reg Sta Equip. TB	379 3000	1,649,337	84,647			1,733,984	112,402	28,943
Services	380 0000	41,880,497	1,505,108			43,385,605	2,440,899	628,532
Meters	381 0000	17,717,846				17,717,846	835,084	163,534
V&P Gauges	381 2000	109,524				109,524		
Meters Installations	382 0000	13,580,843	336,858			13,917,701	834,268	139,943
Regulator Services	383 0000	3,428,992				3,428,992		38,263
Regulators Relief	383 2000	481,545				481,545	140,827	
House Reg Installations	384 0000	159,969	1,822			161,791	2,974	768
Ind. Meas & reg Sta Equip.	385 1000	2,953,710	126,851			3,080,561	104,905	27,013
		153,438,391	3,900,535	0	0	157,338,926	6,949,793	1,350,866
General Plant								
Land	389 1000	44,728				44,728		
Structures & Improvement	390 0200	182,162		134,459		316,621		
Improvements	390 0300	64,111				64,111		
Air Conditioning Equipment	390 0400	9,771				9,771		
Total Energy	390 0500	0				0		
Improvement to leased Premises	390 0900	1,377,286	8,097			1,385,383	13,219	3,404
Office Furniture & equipment	391 0000	1,674,622	1,215	283,245		1,850,082	1,982	811
Office Machines	391 8300	200,479				200,479		
Transportation Equip	392 1000	8,028,858				8,028,858		
Trailers	392 2000	165,970				165,970		
Tool& Work Equipment	394 7700	3,061,056	3,239			3,064,295	8,287	1,362
Ditchers	396 0300	831,023				831,023		
Backhoes	396 0400	706,023				706,023		
Welders	396 0500	92,413				92,413		
Communications equip - phones	397 0000	747,714	32,389	282,328		1,062,431	82,876	13,616
Communications equip - fixed radio	397 2000	21,697	4,859			26,556	7,932	2,043
Communications equip - mobile	397 2100	58,023				58,023		
Communications equip. - telemeterir	397 2200	114,695				114,695		
Misc equip	398 0000	37,073				37,073		
Other tangible property	399 0000	0				0		
Other tangible property - CPU	399 8400	0				0		
Other tangible property MF Hardw	399 8500	404,677				404,677		
Other tangible property-PC Hardw	399 8600	504,428	29,134	2,263,318		2,796,878	47,563	1,216
Other tangible property- PC Softw	399 8700	193,491	8,097	103,668		305,256	13,219	3,404
Other tangible property-appl Softw	399 8800	206,994		9,215,475	2,632,460	12,054,929		
Other tangible property- System Sof	399 8900	0				0		
Server Hardware	39x xx1	0		695,971		695,971		
Server Software	39x xx2	0		228,311		228,311		
Network Cost	39x xx3	0		332,234		332,234		
Start up Cost	39x xx4	0		5,696,631		5,696,631		
Cushion Gas	999 0000	1,694,833				1,694,833		
		18,322,123	87,029	19,235,840	2,632,460	40,277,452	142,078	25,552
		200,375,916	4,073,034	19,235,840	2,632,460	226,317,250	7,200,088	1,411,442

WESTERN KENTUCKY GAS COMPANY

Calculation of December 31, 2000 Plant Balances
For the Test Year Ending December 31, 2000

Description	Acct No.	Plant Balance 9/99	10/99	11/99	12/99	1/00	FY2000 2/00	10/00-12/00 3/00	4/00	5/00	6/00	7/00	8/00	9/00	10/00	11/00	12/00	Average
Intangible Plant																		
Organization	301 0000	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330	8,330
Franchise & Consents	302 0000	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853	119,853
		128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183	128,183
Natural Gas Production																		
Producing Leaseholds	325 2000	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353
Rights of Way	325 4000	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069	6,069
Production Gas Well Equip	331 0000	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492	3,492
Field Lines	332 1000	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183	47,183
Tributary Lines	332 2000	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218	528,218
Field Meas Stat Equip	334 0000	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469	198,469
Purification Equip	338 0000	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369	44,369
		830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133	830,133
Storage Plant																		
Land	350 1000	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127	261,127
Rights of Way	350 2000	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682	4,682
Compression Stat Equip	351 2000	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265	121,265
Meas & Reg Equip	351 3000	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138	23,138
Other Structures	351 4000	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554	144,554
Well Construction	352 0100	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476	2,196,476
Well Equip	352 0200	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976	535,976
Leaseholds	352 1000	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530	178,530
Storage Rights	352 1100	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614	54,614
Field Lines	353 1000	215,734	218,010	220,286	222,561	224,837	227,113	229,389	231,664	233,940	236,216	238,492	240,768	243,043	243,629	244,216	244,801	235,436
Tributary Lines	353 2000	218,158	218,691	219,223	219,755	220,287	220,818	221,350	221,882	222,414	222,946	223,478	224,010	224,542	224,678	224,816	224,952	222,764
Compression Stat Equip	354 0000	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685	470,685
Meas & Reg Equip	355 0000	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851	288,851
Purification Equip	356 0000	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930	239,930
		4,953,721	4,956,529	4,959,336	4,962,144	4,964,952	4,967,759	4,970,567	4,973,375	4,976,182	4,978,990	4,981,798	4,984,605	4,987,413	4,988,138	4,988,858	4,989,582	4,978,028
Transmission Plant																		
Land	365 1000	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951	29,951
Rights of Way	365 2000	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419	403,419
Structures &Improv.	366 2000	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797	14,797
Other Structures	366 3000	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172	69,172
Mains	367 0000	19,314,509	19,320,188	19,325,867	19,331,545	19,337,224	19,342,903	19,348,582	19,354,260	19,359,939	19,365,618	19,371,297	19,376,975	19,382,654	19,384,117	19,385,579	19,387,041	19,363,672
Meas & Reg Equip	369 1000	2,956,987	2,957,519	2,958,050	2,958,582	2,959,113	2,959,645	2,960,176	2,960,708	2,961,239	2,961,771	2,962,302	2,962,834	2,963,365	2,963,365	2,963,365	2,963,365	2,961,525
		22,788,835	22,795,045	22,801,256	22,807,466	22,813,676	22,819,886	22,826,097	22,832,307	22,838,517	22,844,727	22,850,938	22,857,148	22,863,358	22,864,821	22,866,283	22,867,745	22,842,536
Distribution Plant																		
Land Town Border	374 1000	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914	61,914
Land Other	374 3000	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784	2,784
Right Of Way	374 2000	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872	44,872
Structure & Improvements TB	375 1000	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376	106,376
Structure & Improvements Other	375 0200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Improvements	375 0300	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518	7,518
Land Rights	375 2000	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591	46,591
Mains	376 0000	71,043,234	71,278,061	71,512,888	71,747,715	71,982,542	72,217,369	72,452,197	72,687,024	72,921,851	73,156,678	73,391,505	73,626,332	73,861,159	73,885,604	73,910,050	73,934,495	73,050,579
Meas & Reg Sta Equip Gen	378 1000	2,008,087	2,021,463	2,034,839	2,048,216	2,061,590	2,074,966	2,088,341	2,101,717	2,115,093	2,128,468	2,141,844	2,155,219	2,168,595	2,172,039	2,175,484	2,178,928	2,123,884
Meas & Reg Sta Equip TB	379 3000	1,733,984	1,743,351	1,752,718	1,762,085	1,771,452	1,780,819	1,790,185	1,799,552	1,808,919	1,818,286	1,827,653	1,837,020	1,846,387	1,848,798	1,851,210	1,853,622	1,815,070
Services	380 0000	43,385,605	43,589,014	43,792,422	43,995,830	44,199,239	44,402,647	44,606,055	44,809,463	45,012,872	45,216,280	45,419,688	45,623,097	45,826,505	45,878,883	45,931,260	45,983,638	45,146,574
Meters	381 0000	17,717,846	17,770,770	17,823,693	17,876,617	17,929,541	17,982,464	18,035,388	18,088,311	18,141,235	18,194,159	18,247,082	18,300,006	18,352,930	18,366,557	18,380,185	18,393,813	18,176,022
V&P Gauges	381 2000	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524	109,524
Meters Installations	382 0000	13,917,701	13,962,223	14,006,746	14,051,268	14,095,790	14,140,313	14,184,835	14,229,357	14,273,880	14,318,402	14,362,924	14,407,447	14,451,969	14,463,631	14,475,293	14,486,955	14,303,236
Regulator Services	383 0000	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,428,992	3,432,014	3,435,036	3,438,058	3,430,387
Regulators Relief	383 2000	481,545	493,281	505,016	516,752	528,487	540,223	551,958	563,694	575,429	587,165	598,901	610,636	622,372	622,372	622,372	622,372	581,749
House Reg Installations	384 0000	161,791	162,039	162,287	162,535	162,782	163,030	163,278	163,526	163,774	164,022	164,269	164,517	164,765	164,829	164,893	164,957	163,937
Ind Meas & reg Sta Equip	385.1000	3,080,561	3,089,304	3,098,046	3,106,788	3,115,530	3,124,272	3,133,014	3,141,756	3,150,498	3,159,240	3,167,982	3,176,724	3,185,466	3,187,718	3,189,969	3,192,220	3,156,244
		157,336,926	157,918,076	158,497,225	159,076,374	159,655,524	160,234,673	160,813,823	161,392,972	161,972,121	162,551,271	163,130,420	163,709,569	164,288,719	164,402,024	164,515,330	164,628,635	162,336,266
General Plant																		
Land	389 1000	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728	44,728
Structures & Improvement	390 0200	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621	318,621
Improvements	390 0300	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111	64,111
Air Conditioning Equipment	390 0400	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771	9,771
Total Energy	390 0500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Improvement to leased Premises	390 0900	1,385,383	1,386,485	1,387,586	1,388,688	1,389,789	1,390,891	1,391,993	1,393,094	1,394,196	1,395,297	1,396,399	1,397,500	1,398,602	1,398,886	1,399,169	1,399,453	1,394,820
Office Furniture & equipment	391 0000	1,859,082	1,859,247	1,859,412	1,859,577	1,859,742	1,859,907	1,860,073	1,860,238	1,860,403	1,860,568	1,860,733	1,860,899	1,861,064	1,861,106	1,861,149	1,861,191	1,860,512
Office Machines	391 8300	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479	200,479
Transportation Equip	392 1000	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856	6,028,856
Trailers	392 2000	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970	165,970
Tool& Work Equipment	394 7700	3,064,295	3,064,736	3,065,176	3,065,617	3,066,057	3,066,498	3,066,939	3,067,379	3,067,820	3,068,260	3,068,701	3,069,141	3,069,582	3,069,696	3,069,809	3,069,922	3,068,109
Ditchers	396 9300	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023	831,023
Backhoes	396 9400	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023	706,023
Welders	396 9500	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413	92,413
Communications equip - phones	397 0000	1,062,431	1,066,837	1,071,243	1,075,650	1,080,056	1,084,462	1,088,869	1,093,275	1,097,681	1,102,088	1,106,494	1,110,900	1,115,307	1,116,441	1,117,576	1,118,710	1,100,878
Communications equip - fixed radios	397 2000	26,556	27,216	27,877	28,538	29,199	29,860	30,521	31,182	31,843	32,504	33,165	33,826	34,487	34,656	34,828	34,998	32,278
Communications equip - mobile	397 2100	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023	58,023
Communications equip - telemetering	397 2200	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695	114,695
Misc equip	398 0000	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073	37,073
Other tangible property	399 0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other tangible property - CPU	399 8400	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other tangible property MF Hardw	399 8500	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677	404,677
Other tangible property PC Hardw	399 8600	2,796,878	2,800,842	2,804,805	2,808,769	2,812,732	2,816,696	2,820,659	2,824,623	2,828,586	2,832,550	2,836,513	2,840,477	2,844,441	2,844,542	2,844,643	2,844,744	2,830,767
Other tangible property- PC Softw	399 8700	305,256	306,358	307,459	308,561	309,662	310,764	311,866	312,967	314,069	315,170	316,272	317,373	318,475	318,759	319,042	319,326	314,793
Other tangible property appl Softw	399 8800	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929	12,054,929
Other tangible property- System Soft	399 8900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Server Hardware	39x xx1	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971	695,971
Server Software	39x xx2	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311	228,311
Network Cost	39x xx3	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234	332,234
Start up Cost	39x xx4	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831	5,696,831
Cushion Gas	999 0000	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833	1,694,833
		40,277,452	40,289,291	40,301,131	40,312,971	40,324,811	40,336,651	40,348,490	40,360,330	40,372,170	40,384,010	40,395,850	40,407,690	40,419,529	40,421,659	40,423,788	40,425,918	40,379,578
		226,317,250	226,917,257	227,517,264	228,117,271	228,717,278	229,317,285	229,917,293	230,517,300	231,117,307	231,717,314	232,317,321	232,917,328	233,517,335	233,634,956	233,752,576	233,870,196	231,494,874

WESTERN KENTUCKY GAS COMPANY

Calculation of December 31, 2000 Plant Balances- div 02
For the Test Year Ending December 31, 2000

Description	Acct No.	12/99	1/00	FY2000 2/00	10/00-12/00 3/00	4/00	5/00	6/00	7/00	8/00	9/00	10/00	11/00	12/00	Average
General Plant															
Land	389.1000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Structures & Improvement	390.0200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Improvements	390.0300	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Air Conditioning Equipment	390.0400	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Energy	390.0500	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Improvement to leased Premises	390.0900	6,104,534	6,108,438	6,112,341	6,116,244	6,120,147	6,124,050	6,127,953	6,131,856	6,135,759	6,139,662	6,143,557	6,147,451	6,151,345	6,127,949
Office Furniture & equipment	391.0000	3,750,787	3,765,125	3,779,462	3,793,800	3,808,138	3,822,476	3,836,813	3,851,151	3,865,489	3,879,827	3,894,132	3,908,437	3,922,743	3,836,79[illegible]
General Office Equip	391.8200	94,201	94,201	94,201	94,201	94,201	94,201	94,201	94,201	94,201	94,201	94,201	94,201	94,201	94,20[illegible]
Office Machines	391.8300	1,139,014	1,139,361	1,139,708	1,140,055	1,140,401	1,140,748	1,141,095	1,141,442	1,141,789	1,142,136	1,142,482	1,142,828	1,143,175	1,141,095
Transportation Equipment	392.0000	55,388	55,388	55,388	55,388	55,388	55,388	55,388	55,388	55,388	55,388	55,388	55,388	55,388	55,388
Trailers	382.0200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stores Equipment	393.0000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tool & Work Equip	394.7700	39,105	39,105	39,105	39,105	39,105	39,105	39,105	39,105	39,105	39,105	39,105	39,105	39,105	39,105
Dichers	396.9300	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Backhoes	396.9400	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Welders	396.9500	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Communications equip. - phones	397.0000	814,798	815,286	815,775	816,263	816,751	817,240	817,728	818,216	818,705	819,193	819,680	820,168	820,655	817,728
Communications equip. - fixed radi(	397.2000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Communications equip. - mobile	397.2100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Communications equip. - telemeterl	397.2200	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Misc. equip	398.0000	649,344	649,423	649,502	649,581	649,660	649,739	649,818	649,897	649,976	650,055	650,133	650,212	650,291	649,818
Other tangible property	399.0000	61,662	61,662	61,662	61,662	61,662	61,662	61,662	61,662	61,662	61,662	61,662	61,662	61,662	61,662
Other tangible property - CPU	399.8400	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465	1,095,465
Other tangible property-MF Hardw	399.8500	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886	1,171,886
Other tangible property-PC Hardw	399.8800	3,960,117	3,972,846	3,985,576	3,998,305	4,011,035	4,023,764	4,036,493	4,049,223	4,061,952	4,074,682	4,087,382	4,100,083	4,112,784	4,036,480
Other tangible property- PC Softw	399.8600	1,079,034	1,083,712	1,088,391	1,093,069	1,097,747	1,102,425	1,107,104	1,111,782	1,116,460	1,121,138	1,125,806	1,130,474	1,135,142	1,107,099
Other tangible property-appl. Softw	399.8700	40,723,378	41,660,565	42,597,752	43,534,940	44,472,127	45,409,314	46,346,502	47,283,689	48,220,876	49,158,064	49,864,333	50,570,603	51,276,873	46,239,924
Other tangible property- System So	399.8800	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394	2,801,394
		63,540,107	64,513,857	65,487,608	66,461,358	67,435,107	68,408,857	69,382,607	70,356,357	71,330,107	72,303,858	73,046,606	73,789,357	74,532,109	69,275,992

WESTERN KENTUCKY GAS COMPANY

Calculation of Average Combined December 3
For the Test Year Ending December 31, 2000

Description	Acct No.	WKO Only	Div 02	Total Plant	WKO Total Plant		Depre. Rate	Depreciation Expense
Intangible Plant								
Organization	301 0000	8,330		8,330	8,330	0		0
Franchise & Consents	302 0000	119,853		119,853	119,853	0		0
		128,183		128,183	128,183	0		0
Natural Gas Production								
Producing Leaseholds	325 2000	2,353		2,353	2,353	0		0
Rights of Way	325 4000	8,009		8,009	8,009	0		0
Production Gas Well Equip	331 0000	3,492		3,492	3,492	0		0
Field Lines	332 1000	47,163		47,163	47,163	0		0
Tributary Lines	332 2000	528,218		528,218	528,218	0		0
Field Meas. Stat. Equip	334 0000	196,469		196,469	196,469	0		0
Purification Equip	336 0000	44,369		44,369	44,369	0		0
		830,133		830,133	830,133	0		0
Storage Plant								
Land	350.1000	261,127		261,127	261,127	0		0
Rights of Way	350 2000	4,682		4,682	4,682	0	0 92%	0
Compression Stat Equip	351 2000	121,265		121,265	121,774	(509)	1 93%	(10)
Meas & Reg Equip	351 3000	23,138		23,138	23,138	0	1 93%	0
Other Structures	351 4000	144,554		144,554	144,554	0	1 93%	0
Well Construction	352 0100	2,196,476		2,196,476	2,172,800	23,676	2 71%	642
Well Equip	352 0200	635,976		635,976	679,991	(44,015)	2 71%	(1,193)
Leaseholds	352 1000	178,530		178,530	178,530	0	0 30%	0
Storage Rights	352 1100	64,614		64,614	64,614	0	1 83%	0
Field Lines	353 1000	235,436		235,436	261,841	(26,405)	1 35%	(356)
Tributary Lines	353 2000	222,764		222,764	228,934	(6,170)	1 35%	(83)
Compression Stat. Equip	354 0000	470,685		470,685	470,685	0	1 61%	0
Meas & Reg Equip	355 0000	288,851		288,851	288,851	0	2 06%	0
Purification Equip	356 0000	239,930		239,930	239,930	0	1.30%	0
		4,978,028		4,978,028	5,031,451	(53,423)		(1,001)
Transmission Plant								
Land	365 1000	29,951		29,951	29,951	0	0 00%	0
Rights of Way	365 2000	403,419		403,419	403,419	0	0 89%	0
Structures &Improv.	366 2000	14,797		14,797	32,921	(18,124)	1 39%	(252)
Other Structures	366 3000	69,172		69,172	69,172	0	1 39%	0
Mains	367 0000	19,363,672		19,363,672	19,441,293	(77,621)	1 27%	(986)
Meas & Reg Equip	369 1000	2,961,525		2,961,525	2,995,622	(34,097)	2 28%	(777)
		22,842,536		22,842,536	22,972,378	(129,842)		(2,015)
Distribution Plant								
Land Town Border	374 1000	61,914		61,914	61,710	204	0 00%	0
Land Other	374 3000	2,784		2,784	2,784	0	0 00%	0
Right Of Way	374 2000	44,872		44,872	44,872	0	1 68%	0
Structure & Improvements T B	375 1000	106,376		106,376	106,376	0	1 95%	0
Structure & Improvements Other	375 0200	0		0	0	0	1 95%	0
Improvements	375 0300	7,518		7,518	7,518	0	1 95%	0
Land Rights	375 2000	46,591		46,591	46,591	0	1 95%	0
Mains	376 0000	73,059,579		73,059,579	75,047,099	(1,987,520)	2 39%	(47,502)
Meas & Reg. Sta Equip. Gen.	378 1000	2,123,884		2,123,884	2,363,549	(239,665)	2 49%	(5,968)
Meas & Reg. Sta Equip. TB	379 3000	1,815,076		1,815,076	1,917,181	(102,105)	2 57%	(2,624)
Services	380 0000	45,146,574		45,146,574	45,854,769	(708,195)	6 86%	(48,582)
Meters	381 0000	18,176,022		18,176,022	19,396,585	(1,220,563)	3 35%	(40,889)
V&P Gauges	381 2000	109,524		109,524	109,524	0	3 35%	0
Meters Installations	382 0000	14,303,236		14,303,236	14,560,567	(257,331)	3 06%	(7,874)
Regulator Services	383 0000	3,430,387		3,430,387	3,733,713	(303,326)	2 85%	(8,645)
Regulators Relief	383 2000	581,749		581,749	481,545	100,204	2 85%	2,856
House Reg. Installations	384 0000	163,937		163,937	166,402	(2,465)	3 37%	(83)
Ind. Meas. & reg. Sta Equip.	385 1000	3,156,244		3,156,244	3,211,613	(55,369)	2 73%	(1,512)
		162,336,266		162,336,266	167,112,398	(4,776,132)	0 00%	(160,823)
General Plant								
Land	389 1000	44,728	0	44,728	44,728	0	0 00%	0
Structures & Improvement	390 0200	318,621	0	318,621	318,621	0	2 12%	0
Improvements	390 0300	64,111	0	64,111	64,111	0	2 12%	0
Air Conditioning Equipment	390 0400	9,771	0	9,771	9,771	0	2 12%	0
Total Energy	390 0500	0	0	0	0	0	0 00%	0
Improvement to leased Premises	390 0900	1,394,920	980,472	2,375,392	2,504,775	(129,383)	5 00%	(6,469)
Office Furniture & equipment	391 0000	1,660,512	813,888	2,474,399	2,550,590	(76,191)	7 05%	(5,371)
General Office Equip	391 8200	0	15,072	15,072	16,098	(1,026)		0
Office Machines	391 8300	200,479	182,575	383,054	405,141	(22,087)	7 05%	(1,557)
Transportation Equip	392 1000	6,028,856	8,862	6,037,718	6,054,009	(16,291)	8 92%	(1,453)
Trailers	392 2000	165,970	0	165,970	165,970	0	8 92%	0
Stores Equipment	393 0000	0	0	0	0	0	0 00%	0
Tool& Work Equipment	394 7700	3,066,109	8,257	3,074,366	3,082,589	(8,223)	3 28%	(270)
Dichers	396 9300	831,023	0	831,023	853,615	(22,592)	2 79%	(630)
Backhoes	396 9400	706,023	0	706,023	706,023	0	2 79%	0
Welders	396 9500	92,413	0	92,413	92,413	0	2 79%	0
Communications equip - phones	397 0000	1,100,578	130,836	1,231,414	1,293,379	(61,965)	5 21%	(3,228)
Communications equip - fixed radi	397 2000	32,278	0	32,278	28,653	3,625	5 21%	189
Communications equip - mobile	397 2100	58,023	0	58,023	68,220	(10,197)	5 21%	(531)
Communications equip - telemeteri	397 2200	114,695	0	114,695	114,695	0	5 21%	0
Misc. equip	398 0000	37,073	103,971	141,044	153,632	(12,588)	10 94%	(1,377)
Other tangible property	399 0000	0	9,866	9,866	11,061	(1,195)	0	0
Other tangible property - CPU	399 8400	0	175,274	175,274	196,508	(21,234)	0	0
Other tangible property-MF Hardw	399 8500	404,677	187,502	592,179	607,494	(15,315)	1 19%	(182)
Other tangible property-PC Hardw	399 8600	2,830,767	645,837	3,476,604	3,551,824	(75,220)	18 51%	(13,923)
Other tangible property- PC Softw	399 8700	314,793	177,136	491,929	546,060	(54,131)	15 85%	(8,580)
Other tangible property-appl Softw	399 8800	12,054,929	7,398,388	19,453,317	20,278,490	(825,173)	12 50%	(103,147)
Other tangible property- System So	399 8900	0	448,223	448,223	502,523	(54,300)	0 00%	0
Server Hardware	39x xx1	695,971		695,971	695,971	0	14 29%	0
Server Software	39x xx2	228,311		228,311	228,311	0	14 29%	0
Network Cost	39x xx3	332,234		332,234	332,234	0	14 29%	0
Start up Cost	39x xx4	5,696,831		5,696,831	5,696,831	0	8 33%	0
Cushion Gas	909 0000	1,694,833		1,694,833	1,694,833	0		0
		40,379,528	11,084,159	51,463,687	52,867,973	(1,404,286)		(148,631)
		231,494,674	11,084,159	242,578,833	248,942,516	(6,363,683)		(310,369)

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

12. Refer to Schedule LKM-7 of Mr. Morgan's Direct Testimony.

a. Provide the calculations referenced in Note No. 1 on this schedule. Include citations to the specific data responses used in these calculations.

b. Does Mr. Morgan agree with Western's contention that the PSC Assessment should be included as part of the prepayments? Explain the response.

Response

a. See the attached workpaper.

b. Yes. According to the response to AG Initial Data Request NO. 234, the KPSC assessment fee is sent by July 1st and should be paid by July 31st. The balance in the PSC assessments account supports that pattern of assessments. I believe that the PSC assessment is a legitimate expense for a natural gas utility in the state of Kentucky.

/2781/lkm/datareq/kpsc_response.wpd

Responsible Witness: Lafayette K. Morgan, Jr.

WESTERN KENTUCKY GAS COMPANY

Calculation of Prepayments
For the Test Year Ending December 31, 2000

Description		Dec. 99	Jan. 00	Feb. 00	Mar. 00	Apr. 00	May 00	Jun. 00	Jul. 00	Aug. 00	Sep. 00	Oct. 00	Nov. 00	Dec. 00	13-Month Average
Division 09															
Workers Comp	1/	0	19,250	0	0	0	0	0	0	0	0	0	0	0	1,481
Property Ins	1/	26,584	24,168	21,752	19,936	16,920	14,504	12,088	9,672	7,256	4,840	2,424	29,000	28,584	16,594
Auto Liability	1/	0	(6,000)	0	0	0	(6,000)	0	(5,800)	(6,169)	0	0	0	0	(1,851)
Liability Ins	1/	82,500	75,000	67,500	60,000	52,500	45,000	37,500	30,000	22,500	15,000	7,500	9,000	82,500	45,115
Amer Ins Co	1/	73,334	66,668	60,002	53,336	46,670	40,004	33,338	26,672	20,006	13,340	6,674	80,000	73,334	45,644
AEGIS Off & Dir Liab.	1/	100,834	91,668	82,502	73,336	64,170	55,004	45,838	36,672	27,506	18,340	9,174	100,834	91,668	61,350
PSC Assessment	1/	90,816	69,892	55,913	41,934	27,955	13,976	155,833	141,666	127,499	113,332	89,165	84,998	70,831	84,139
Division 09 Subtotal		374,068	340,646	287,669	248,542	208,215	162,488	284,597	238,782	198,698	164,852	124,937	303,832	344,917	252,47[illegible]
Division 02															
Workers Comp	1/	0	838	0	0	0	0	0	0	0	0	0	0	0	64
Property Ins	1/	0	0	0	0	0	2,370	0	0	0	0	0	0	0	182
Liability Ins	1/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SEBP Ins	1/	365,476	307,383	246,873	186,363	393,486	508,977	449,675	449,675	390,373	543,381	485,287	425,986	366,684	393,817
Postage	1/	(6,701)	(15,805)	(11,989)	8,011	13,011	22,000	8,038	9,794	3,863	3,863	3,863	3,863	3,863	3,506
Inserter	1/	55,000	45,000	(45,000)	26,649	22,884	19,698	64,855	(7,500)	6,870	(15,500)	17,573	21,894	21,894	18,024
Mail Box	1/	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
Business Reply	1/	2,466	3,404	3,241	3,241	3,241	3,375	3,328	3,305	3,263	3,263	3,263	3,263	3,263	3,224
Postage Due	1/	53	52	13	13	13	372	371	370	345	345	345	345	345	229
Lincoln Center Mail Room	1/	44	44	44	44	44	44	44	44	44	44	44	44	44	44
CIS Project	2/	275,000	250,000	225,000	200,000	175,000	150,000	125,000	100,000	75,000	50,000	25,000	0	275,000	148,077
Oracle Database Maint	2/	8,025	71,924	65,385	58,846	52,307	45,768	39,229	32,690	26,151	19,612	13,073	6,534	0	33,811
Southern Gas Assoc	1/	0	14,663	13,330	11,997	10,664	9,331	7,998	6,665	5,332	3,899	2,666	1,333	0	6,768
American Gas Assoc.	1/	0	21,762	21,762	21,762	21,762	22,362	11,249	1,102	(10,147)	4,853	14,853	34,853	16,853	14,079
NationsBank of Texas	2/	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Int of Gas Tech	1/	0	23,000	20,910	18,820	16,730	14,640	12,550	10,460	8,370	6,280	4,190	2,100	0	10,619
Division 02 Subtotal		699,290	722,092	539,496	535,673	709,069	798,864	722,264	606,532	509,391	620,067	570,084	500,142	687,873	632,372
Western Kentucky Percentage		16.657%	16.657%	16.657%	16.657%	16.657%	16.657%	16.657%	16.657%	16.657%	16.657%	16.657%	16.657%	16.657%	
Western Kentucky Portion		116,481	120,279	89,864	89,227	118,110	133,067	120,308	101,030	84,849	103,285	94,959	83,309	114,579	105,334
Total Prepaids - WKG															357,807

Notes:
1/ Response to AG 1-235
2/ Response to AG 2-19 (a,b & c)

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

13. The Direct Testimony of Richard A. Galligan and Steven L. Estomin both include criticisms of Western's proposed cost-of-service study. Mr. Galligan performs a separate cost-of-service study that, if followed, would result in allocating Western's proposed increase differently than Western has proposed. However, Mr. Galligan does not recommend that his study be followed; but that all customer classes receive a proportional share of the revenue increase. Given that ultimate recommendation, explain in detail the reasons for Mr. Galligan performing the cost-of-service study summarized in his testimony.

Response

As explained on page 3 of Mr. Galligan's testimony, the Company's cost of service study cannot be relied upon as an accurate indication of class cost responsibilities. As explained on page 19 of Mr. Galligan's testimony, the Company's revenue increase proposal is not consistent with a cost of service study which properly allocates costs. It was necessary for Mr. Galligan to perform a cost of service study to determine a proper allocation of costs.

Prepared by: Jerome D. Mierzwa

Responsible Witness: Richard A. Galligan

WESTERN KENTUCKY GAS COMPANY
DOCKET NO. 99-070
ATTORNEY GENERAL'S RESPONSE KPSC
DATA REQUEST
SET I

14. Mr. Galligan recommends the Commission reject Western's proposed Margin Loss Recovery Rider and its proposed Premises Charge. However, Mr. Galligan's testimony makes no mention of Western's proposed Weather Normalization Adjustment ("WNA") mechanism.

a. Explain whether Mr. Galligan conducted any analysis of Western's proposed WNA.

b. Provide a detailed description of Mr. Galligan's analysis of the proposed WNA.

c. Given the absence of any criticism of the proposed WNA in his testimony, it appears that Mr. Galligan accepts Western's proposal. Explain how Mr. Galligan's analysis led him to accept, or not oppose, Western's WNA.

Response

a. Yes.

b. Mr. Galligan, with the assistance of other Exeter staff, reviewed the proposed operation of the WNA, primarily through conducting discovery.

c. Mr. Galligan has some concerns with procedures for adjusting all customers' bills, regardless of the sensitivity of a given customer's use to fluctuations in temperature as well as with the procedure for calculating the overall weather adjustment factor. Nevertheless, Mr. Galligan decided that the overall WNA was not unreasonable and decided not to oppose it.

2781/rag/datareq/ag_set-i.wpd

Prepared by: Thomas S. Catlin

Responsible Witness: Richard A. Galligan

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
Request for Information by
Public Service Commission

15. Refer to pages 32 and 33 of the Direct Testimony of Dr. Carl G. K. Weaver.

a. Did Dr. Weaver examine or evaluate the reasonableness of the capital structure proposed by Western for the forecasted period? If yes, what were the results of that examination? If no, explain why such an examination was not performed.

Answer:

Yes, I did examine the reasonableness of Atmos capital structure. Please refer to Schedule 7 of my exhibit to see the results of that examination.

On Schedule 7, I show the capital structures of the four companies that I selected for obtaining data for this analysis. The four companies have a total of 54.9% leverage components in their capital structure. (Sum of short-term debt, long-term debt, and preferred stock.) The actual capital structure for Atmos has 58.5% leverage components, or 3.6% more. Western's Witness John Reddy, in his direct testimony beginning at line 8 on page 4 and continuing through line 12 of page 5 describes reasons why Atmos has a higher amount of leverage.

Atmos forecasted capital structure is also shown on Schedule 7. This structure has 5.1% less leverage than the four companies. Mr. Reddy's explanation of the transactions and events that will cause the reduction is leverage appear reasonable.

Atmos has a consolidated statement of stockholders equity in the 1998 Stockholders Annual Report on page 26. This shows that paid-in-capital and retained earnings increased by $23.4 million between September 30, 1997 and September 30, 1998. During this same period, paid-in-capital increased by $20.4 million. The retained earnings increase was from the amount of net income that was retained after dividends were paid. The additional paid-in-capital was derived from the various stock plans.

Atmos' forecast indicates that equity is expected to increase in the base year by $28.2 million and by $45.9 million from December 31, 1999 to December 31, 2000. Given the changes that occurred between 1997 and 1998, I do not find the forecast assumptions unreasonable.

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
Request for Information by
Public Service Commission

16. Concerning the development of a forecasted capital structure for Atmos and Western, for each of the assumptions listed below, indicate if Dr. Weaver believes the assumption is reasonable for Atmos.

a. A return to normal long-term weather patterns for the other Atmos utility divisions beginning in FY 2000.

Answer: Yes.

b. The issuance of $26 million of new equity in November 1999.

Answer: Yes, it is a reasonable assumption. It is shown in FR 10 (9)(h) 11 going from sheet 1 of 3 to sheet 2 of 3.

c. Raising $20 million of new equity annually through stock plans.

Answer: Yes, see response to question 15.

d. No significant acquisitions.

Answer: Yes, FR 10(9)(h)3, the forecasted cash flow statement for Western, shows the total cash flow from investments (capital expenditures) averaging $18.7 million in 1998 and 1999 and falling to $11.8 million in the calendar year 2000. In the 1998 Stockholders Annual Report, on pages 52 and 53, the company indicates that internally generated funds will cover its capital expenditure need, which is budgeted to be $86.8 million, in 1999. This budgeted amount is a reduction from the $135 million shown on the cash flow statement in 1998 and this also indicates a reduction in acquisitions.

e. Cash flow from depreciation will fund ongoing capital spending requirements.

Answer: Yes. Atmos cash flow statement, shown on page 27 of the 1998 Stockholders Annual Report and summarized in Schedule 12 of my exhibit shows that cash flow from operating activities covered cash outflow for investing activities .67 times in 1997 and 1998. The reductions discussed in question d above should provide sufficient funds so that cash flow from operating activities covers cash flow from investing activities.

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
Request for Information by
Public Service Commission

17. Refer to the Dr. Weaver's Direct Testimony. Identify any of Dr. Weaver's comparable companies that use WNA mechanisms, Premises Charges, or Margin Loss Recovery Riders such as those proposed by Western.

Answer:

Energen's subsidiary, the Alabama Gas Corporation, has a Rate Stabilization and Equalization Plan which maintains rates for this gas subsidiary within a range of its authorized return. (Value Line, June 25, 1999)

Laclede Gas has a Price Stabilization Program which offers price protection for natural gas to customers above a redetermined level and for Laclede to share gains that result. It also has a gas supply incentive plan which benefit shareholders and customers outside the company's traditional sales areas.(Value Line, September 24, 1999)

New Jersey Resources has a weather normalization clause. (Value Line, March 26, 1999)

Piedmont has a weather normalization clause. According to Value Line, it "works well when the average temperature is within 8% of the norm. Through the end of the third quarter, Piedmont's number of heating degree days was 16% below average." (Value Line, September 24, 1999)

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
Request for Information by
Public Service Commission

18. Explain whether Dr. Weaver's analysis of Western's cost of equity reflects Western's proposed WNA mechanism; its proposed Premises Charge; or its proposed Margin Loss Recovery Rider. If it does not, explain how the approval of each of these mechanisms would impact Dr. Weaver's recommended return on equity range. Quantify the effect of including each mechanism in the analysis, and include all supporting calculations.

Answer:

The cost of equity recommendation, as stated on page 32 at line 4, reflects WKGC's use of a forecasted test year. On lines 9 and 10, it is stated that anticipated expenses have been incorporated into the determination of the test-year. Anticipated revenues were also incorporated into the test year.

It is important to note that, as is stated in Appendix II on page 4, line 1, "Risk, as it applies to the cost of equity, should be considered as total risk rather than the risk that would result from the occurrence of any single factor." The 9.75% to 10.75% cost of equity range that is recommended is below two of the four measures obtained using the selected companies' data.

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
Request for Information by
Public Service Commission

19. If already provided, provide copies of all source documents used in calculating Western's cost of equity.

Answer: attached

ATMOS ENERGY CORP. NYSE-ATO

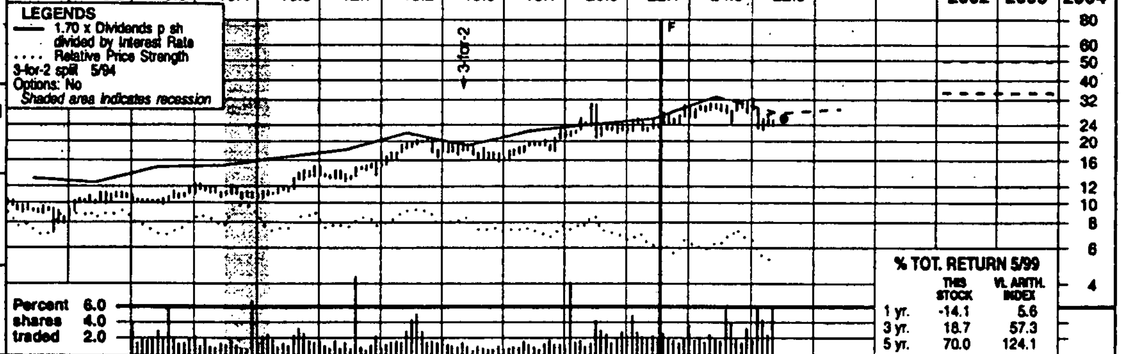
RECENT PRICE **26** | P/E RATIO **16.9** (Trailing: 18.3; Median: 15.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **4.3%** | VALUE LINE **468**

TIMELINESS **5** Lowered 3/19/99
SAFETY **2** Raised 6/25/99
TECHNICAL **4** Lowered 6/4/99
BETA .55 (1.00 = Market)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
High:	11.5	12.0	12.5	15.3	15.9	21.2	20.3	23.0	31.0	30.5	32.3	33.0
Low:	8.2	9.8	10.4	10.5	12.7	15.2	15.9	16.1	20.9	22.1	24.8	22.8

Target Price Range 2002 | 2003 | 2004

LEGENDS
— 1.70 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 5/94
Options: No
Shaded area indicates recession



% TOT. RETURN 5/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	-14.1	5.6
3 yr.	18.7	57.3
5 yr.	70.0	124.1

2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+90%)	21%
Low	35	(+35%)	11%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	4	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q1998	3Q1998	4Q1998
to Buy	45	46	55
to Sell	24	27	26
Hld's(000)	9724	10049	10602

Percent shares traded 6.0 4.0 2.0

Atmos Energy's history dates back to 1906 and the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, and United Cities Gas in 1997.

1989	1990	1991	1992	1993	F1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
37.46	38.46	33.04	32.46	31.94	32.67	28.08	30.19	30.59	27.90	*23.55*	*29.20*	Revenues per sh A	*39.40*
2.48	2.68	2.38	2.63	2.39	2.19	2.55	2.80	2.85	3.38	*3.15*	*4.00*	"Cash Flow" per sh	*5.65*
.89	.98	.80	.97	1.19	.97	1.22	1.51	1.34	1.84	*1.35*	*2.00*	Earnings per sh B	*3.00*
.75	.77	.80	.83	.86	.88	.92	.96	1.01	1.06	*1.10*	*1.15*	Div'ds Decl'd per sh C■	*1.30*
2.37	2.77	2.97	3.18	2.67	3.29	4.05	4.84	4.13	4.44	*2.75*	*2.30*	Cap'l Spending per sh	*3.80*
8.50	8.71	8.88	9.17	9.64	9.78	10.20	10.75	11.04	12.21	*12.75*	*13.80*	Book Value per sh	*18.50*
9.14	9.15	10.17	10.48	14.38	15.30	15.52	16.02	29.64	30.40	*31.00*	*31.50*	Common Shs Outst'g D	*33.00*
11.9	11.7	14.4	14.2	14.7	19.2	15.0	15.1	17.9	15.4	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.90	.87	.92	.86	.87	1.26	1.00	.95	1.03	.81	*Value Line*		Relative P/E Ratio	*.95*
7.1%	6.7%	6.9%	6.0%	4.9%	4.7%	5.0%	4.2%	4.2%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*
342.4	352.0	336.1	340.1	459.4	499.8	435.8	483.7	906.8	848.2	*730*	*920*	Revenues ($mill) A	*1300*
8.1	9.0	7.9	10.0	17.0	14.7	18.8	23.9	39.2	55.3	*40.0*	*65.0*	Net Profit ($mill)	*100*
31.4%	32.2%	27.5%	32.7%	37.7%	35.5%	33.8%	35.7%	37.5%	36.5%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
2.4%	2.5%	2.4%	2.9%	3.7%	2.9%	4.3%	5.0%	4.3%	6.5%	*5.5%*	*6.9%*	Net Profit Margin	*7.6%*
54.2%	51.7%	52.3%	49.7%	43.3%	48.0%	45.3%	41.5%	48.1%	51.8%	*53.0%*	*51.0%*	Long-Term Debt Ratio	*53.0%*
45.8%	48.3%	47.7%	50.3%	56.7%	52.0%	54.7%	58.5%	51.9%	48.2%	*47.0%*	*49.0%*	Common Equity Ratio	*47.0%*
169.7	165.2	189.5	190.8	244.6	287.9	289.6	294.6	630.2	769.7	*845*	*885*	Total Capital ($mill)	*1300*
194.8	194.9	205.7	219.4	299.3	327.4	363.3	413.6	849.1	917.9	*950*	*1000*	Net Plant ($mill)	*1200*
7.3%	8.1%	6.6%	7.9%	9.2%	7.2%	8.9%	10.6%	8.3%	9.0%	*6.5%*	*9.0%*	Return on Total Cap'l	*9.0%*
10.4%	11.2%	8.8%	10.4%	12.3%	9.8%	11.9%	13.9%	12.0%	14.9%	*10.5%*	*14.5%*	Return on Shr. Equity	*16.5%*
10.4%	11.2%	8.8%	10.4%	12.3%	9.8%	11.9%	13.9%	12.0%	14.9%	*10.5%*	*14.5%*	Return on Com Equity	*16.5%*
1.6%	2.4%	--	1.6%	5.6%	1.3%	2.9%	5.1%	3.9%	6.3%	*2.0%*	*6.0%*	Retained to Com Eq	*9.0%*
84%	79%	100%	85%	54%	86%	76%	64%	67%	58%	*81%*	*57%*	All Div'ds to Net Prof	*43%*

CAPITAL STRUCTURE as of 3/31/99
Total Debt $517.7 mill. Due in 5 Yrs $195.0 mill.
LT Debt $386.6 mill. LT Interest $25.0 mill.
(LT interest earned: 4.1x; total interest coverage: 3.5x) (49% of Cap'l)

Leases, Uncapitalized Annual rentals $9.6 mill.
Pfd Stock None

Common Stock 30,868,815 shs. (51% of Cap'l) as of 4/30/99

MARKET CAP: $800 million (Small Cap)

CURRENT POSITION ($MILL.)	1997	1998	3/31/99
Cash Assets	6.0	4.7	14.6
Other	137.7	102.7	142.6
Current Assets	143.7	107.4	157.2
Accts Payable	62.6	44.7	71.7
Debt Due	182.5	124.2	131.1
Other	68.1	55.2	63.8
Current Liab.	313.2	224.1	266.6
Fix. Chg. Cov.	272%	401%	365%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	-2.5%	-2.0%	*5.0%*
"Cash Flow"	3.5%	4.0%	*11.0%*
Earnings	4.5%	9.5%	*11.5%*
Dividends	4.0%	4.0%	*4.5%*
Book Value	4.5%	4.0%	*8.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	130.5	191.1	93.6	68.5	483.7
1997	280.6	362.6	143.7	119.9	906.8
1998	295.3	288.6	137.3	127.0	848.2
1999	210.2	261.4	*133.4*	*125*	*730*
2000	*280*	*315*	*175*	*150*	*920*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	.59	1.15	.02	d.25	1.51
1997	.62	1.14	d.10	d.32	1.34
1998	.68	1.25	.04	d.13	1.84
1999	.50	1.01	*.01*	*d.17*	*1.35*
2000	*.69*	*1.35*	*.06*	*d.10*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.23	.23	.23	.24	.93
1996	.24	.24	.24	.25	.97
1997	.25	.25	.255	.265	1.02
1998	.265	.265	.265	.275	1.07
1999	.275	.275			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas through five regulated natural gas utility divisions: Energas Co. in West Texas (300,000 customers), Western Kentucky Gas Utility (176,000), Trans Louisiana Gas (81,000), Greeley Gas (115,000), and United Cities Gas (316,000). Combined 1998 volume handled: 159 Bcf. Breakdown: 46%, residential; 23%, commercial; 31%, industrial and other. '98 depreciation rate 3.3%. Has 2,193 employees, 38,949 common stockholders. Officers and directors own approx. 1.2% of common stock (12/98 Proxy). Chairman, C.E.O., & President: Robert Best. Inc.: Texas. Address: P.O. Box 650205, Dallas, TX 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy Corp. is having a rough year, as earnings for the first six months, ended March 31st, slid 22% versus last year's tally. (Our figures exclude a 7¢ charge in the second quarter of '99 from a lawsuit in Louisiana). The major detractor to performance continued to be abnormal weather, as temperatures were 16% warmer than usual and 13% warmer than last year's first six months. In light of the company's lower-than-expected results during the first half (where natural gas consumption tends to be the highest), we expect share net to decline over 25%, to $1.35, in 1999. Assuming a return to more normal weather patterns in the coming heating season, the bottom line should rebound sharply in fiscal 2000.

Despite the company's lower first-half results, there were some bright spots. Its customer base in Colorado, mid-Tennessee, and Kansas (currently comprising over 300,000 people, in all) continued to expand during the period, reflecting heavy industrial activity in those areas. In addition, Atmos' non-utility operations posted respectable results, as they added 12% to net income for the first six months. A major contributor in this segment was 45%-owned Woodward Marketing, which provides natural gas services for local distribution companies (LDCs) and municipalities. ATO also benefited from weather normalized rates in Tennessee and Georgia (normalization means that customers pay more than their actual usage for gas when temperatures are warmer than usual and vice versa).

The company's future appears bright. We believe ATO's ability to successfully integrate acquired firms is a key competitive advantage and may result in steady earnings gains in the coming years. Moreover, we view its significant non-utility operations as a major plus. In 1998, they added about 20% to net income and we believe that further expansionary efforts could enable them to contribute between 25% to 30% annually going forward.

These shares are ranked to lag the market over the coming year. But they offer good total-return potential over the 3- to 5-year period. Income-oriented investors should note the stock's attractive dividend yield, based on a growing payout.

Frederick L. Harris, III *June 25, 1999*

(A) Fiscal year ends Sept. 30th.
(B) Diluted shrs. Excludes nonrecurring losses: '97, 53¢; '99, 7¢. Next egs report due late July.
(C) Next div. meeting about Aug. 10th. Goes ex about Aug. 20th. Approximate div. pmt. dates: 10th of March, June, Sept., Dec. ■ Div. reinvestment plan avail. (3% discount).
(D) In millions, adjusted for stock splits.
(E) Years prior to 1994 are not comparable due to acquisition using pooling of interest method.
(F) Atmos completed its merger with United Cities Gas Company in July, 1997.

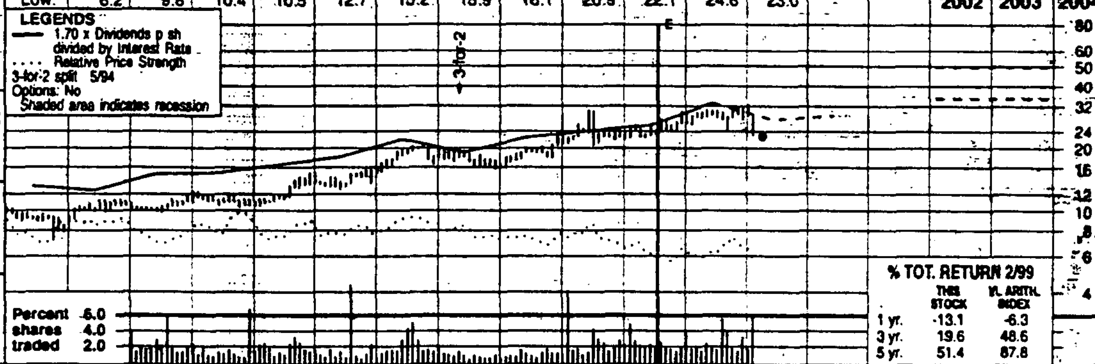
Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	75
Earnings Predictability	60

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 23 | P/E RATIO 14.4 (Trailing: 13.9; Median: 15.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 4.8% | VALUE LINE 468

TIMELINESS 5 Lowered 3/19/99
SAFETY 3 Lowered 9/27/96
TECHNICAL 3 Raised 2/20/98
BETA .55 (1.00 = Market)

														Target Price Range 2002 / 2003 / 2004
High:	11.5	12.0	12.5	15.3	15.9	21.2	20.3	23.0	31.0	30.5	32.3	33.0		
Low:	8.2	9.8	10.4	10.5	12.7	15.2	15.9	16.1	20.9	22.1	24.8	23.0		



2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+115%)	24%
Low	35	(+50%)	15%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q1998	3Q1998	4Q1998
to Buy	45	46	55
to Sell	24	27	26
Hld's(000)	9724	10049	10602

% TOT. RETURN 2/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	-13.1	-6.3
3 yr.	19.6	48.6
5 yr.	51.4	87.8

Atmos Energy's history dates back to 1906 and the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, and United Cities Gas in 1997.

1989	1990	1991	1992	1993	D1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
37.46	38.46	33.04	32.46	31.94	32.67	28.08	30.19	30.59	27.90	*23.90*	*30.15*	Revenues per sh A	*39.40*
2.48	2.68	2.38	2.63	2.39	2.19	2.55	2.80	2.85	3.38	*3.40*	*3.90*	"Cash Flow" per sh	*5.65*
.89	.98	.80	.97	1.19	.97	1.22	1.51	1.34	1.84	*1.60*	*2.00*	Earnings per sh A	*3.00*
.75	.77	.80	.83	.86	.88	.92	.96	1.01	1.06	*1.10*	*1.15*	Div'ds Decl'd per sh B■	*1.30*
2.37	2.77	2.97	3.18	2.67	3.29	4.05	4.84	4.13	4.44	*2.75*	*2.70*	Cap'l Spending per sh	*3.80*
8.50	8.71	8.88	9.17	9.64	9.78	10.20	10.75	11.04	12.21	*12.90*	*14.00*	Book Value per sh	*18.50*
9.14	9.15	10.17	10.48	14.38	15.30	15.52	16.02	29.64	30.40	*31.00*	*31.50*	Common Shs Outst'g C	*33.00*
11.9	11.7	14.4	14.2	14.7	19.2	15.0	15.1	17.9	15.4	*Bold figures are*		Avg Ann'l P/E Ratio	*14.00*
.90	.87	.92	.86	.87	1.26	1.00	.95	1.03	.81	*Value Line*		Relative P/E Ratio	*.95*
7.1%	6.7%	6.9%	6.0%	4.9%	4.7%	5.0%	4.2%	4.2%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*
342.4	352.0	336.1	340.1	459.4	499.8	435.8	483.7	906.8	848.2	*740*	*950*	Revenues ($mill) A	*1300*
8.1	9.0	7.9	10.0	17.0	14.7	18.8	23.9	39.2	55.3	*50.0*	*65.0*	Net Profit ($mill)	*100*
31.4%	32.2%	27.5%	32.7%	37.7%	35.5%	33.8%	35.7%	37.5%	36.5%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
2.4%	2.5%	2.4%	2.9%	3.7%	2.9%	4.3%	5.0%	4.3%	6.5%	*6.7%*	*6.6%*	Net Profit Margin	*7.6%*
54.2%	51.7%	52.3%	49.7%	43.3%	48.0%	45.3%	41.5%	48.1%	51.8%	*55.0%*	*57.0%*	Long-Term Debt Ratio	*53.0%*
45.8%	48.3%	47.7%	50.3%	56.7%	52.0%	54.7%	58.5%	51.9%	48.2%	*45.0%*	*43.0%*	Common Equity Ratio	*47.0%*
169.7	165.2	189.5	190.8	244.6	287.9	289.6	294.6	630.2	769.7	*900*	*1025*	Total Capital ($mill)	*1300*
194.8	194.9	205.7	219.4	299.3	327.4	363.3	413.6	849.1	917.9	*950*	*1000*	Net Plant ($mill)	*1175*
7.3%	8.1%	6.6%	7.9%	9.2%	7.2%	8.9%	10.6%	8.3%	9.0%	*7.0%*	*8.0%*	Return on Total Cap'l	*9.0%*
10.4%	11.2%	8.8%	10.4%	12.3%	9.8%	11.9%	13.9%	12.0%	14.9%	*12.5%*	*14.5%*	Return on Shr. Equity	*16.0%*
10.4%	11.2%	8.8%	10.4%	12.3%	9.8%	11.9%	13.9%	12.0%	14.9%	*12.5%*	*14.5%*	Return on Com Equity	*16.0%*
1.6%	2.4%	--	1.6%	5.6%	1.3%	2.9%	5.1%	3.9%	6.3%	*4.0%*	*6.0%*	Retained to Com Eq	*9.0%*
84%	79%	100%	85%	54%	86%	76%	64%	67%	58%	*69%*	*57%*	All Div'ds to Net Prof	*43%*

CAPITAL STRUCTURE as of 12/31/98
Total Debt $576.3 mill. Due in 5 Yrs $195.0 mill.
LT Debt $390.4 mill. LT Interest $25.0 mill.
Incl. $7.9 mill. capitalized leases.
(LT interest earned: 4.1x; total interest coverage: 3.5x) (50% of Cap'l)

Leases, Uncapitalized Annual rentals $9.2 mill.
Pfd Stock None.

Common Stock 30,653,887 shs. (50% of Cap'l)
MARKET CAP: $700 million (Small Cap)

CURRENT POSITION ($MILL.)	1997	1998	12/31/98
Cash Assets	6.0	4.7	14.7
Other	137.7	102.7	186.4
Current Assets	143.7	107.4	201.1
Accts Payable	62.6	44.7	80.8
Debt Due	182.5	124.2	185.9
Other	68.1	55.2	49.7
Current Liab.	313.2	224.1	316.4
Fix. Chg. Cov.	272%	401%	350%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	-2.5%	-2.0%	*5.0%*
"Cash Flow"	3.5%	4.0%	*11.0%*
Earnings	4.5%	9.5%	*11.5%*
Dividends	4.0%	4.0%	*4.5%*
Book Value	4.5%	4.0%	*8.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	130.5	191.1	93.6	68.5	483.7
1997	280.6	362.6	143.7	119.9	906.8
1998	295.3	288.6	137.3	127.0	848.2
1999	210.2	*250*	*145*	*134.8*	*740*
2000	*290*	*320*	*180*	*160*	*950*

Fiscal Year Ends	EARNINGS PER SHARE A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	.59	1.15	.02	d.25	1.51
1997	.62	1.14	d.10	d.32	1.34
1998	.68	1.25	.04	d.13	1.84
1999	.50	*1.15*	*.05*	*d.10*	*1.60*
2000	*.69*	*1.35*	*.06*	*d.10*	*2.00*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.23	.23	.23	.24	.93
1996	.24	.24	.24	.25	.97
1997	.25	.25	.255	.265	1.02
1998	.265	.265	.265	.275	1.07
1999	.275				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas through five regulated natural gas utility divisions: Energas Co. in West Texas (300,000 customers), Western Kentucky Gas Utility (176,000), Trans Louisiana Gas (81,000), Greeley Gas (115,000), and United Cities Gas (318,000). Combined 1998 volume handled: 159 Bcf. Breakdown: 46%, residential; 23%, commercial; 31%, industrial and other. '98 depreciation rate 3.3%. Has 2,193 employees, 36,949 common stockholders. Officers and directors own approx. 1.2% of common stock (12/98 Proxy). Chairman, C.E.O., & President: Robert Best. Inc.: Texas. Address: P.O. Box 650205, Dallas, TX 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy began 1999 on a sour note. (Fiscal year ends September 30th.) Earnings for the first-quarter fell over 25% compared to the same period in 1998, attributable largely to average temperatures that were 15% warmer than normal and 22% warmer than a year ago. Mother Nature took a huge bite out of the company's top line, as revenues plummeted nearly 30% versus the year-ago tally. As it appears that abnormal weather conditions persisted during the second quarter, we have slashed this year's share-net estimate by $0.35, to $1.60.

But the company has managed to keep costs under control. As a result of ATO's highly successful integration of United Cities Gas, along with the streamlining of other businesses, operation and maintenance expenses declined around 24% last year. Though we believe further restructuring efforts will continue to bolster the company's results over the long term, they won't be sufficient to offset this year's unfavorable weather conditions. But assuming normal temperatures in fiscal 2000, we expect earnings to rebound sharply.

Atmos is one of the more aggressively managed natural gas utilities that *Value Line* tracks, as it has successfully completed four major acquisitions over the past 13 years. As part of its strategy for long-term growth, management pursues firms which can enhance ATO's economies of scale. With the unbundling of services in the natural gas industry, combined with an increasingly competitive environment, we believe that Atmos' skill in acquiring companies could help foster solid top- and bottom-line gains in the coming years. (Our estimates and projections do not include the prospect of acquisitions, due to the various uncertainties associated with that strategy.)

Though untimely for the year ahead, this stock has decent total return potential over the 2002-2004 period. Income-conscious investors should note that it offers a healthy dividend, which has been increasing steadily over the years. But interested parties should be aware that Atmos shares (like all utilities issues) are susceptible to interest-rate changes.

Frederick L. Harris, III *March 26, 1999*

(A) Fiscal year ends Sept. 30th. Next earnings report due late April.
(B) Next div. meeting about May 10th. Goes ex about May 20th. Approximate div. pmt. dates: 10th of March, June, Sept., Dec. ■ Div. reinvestment plan avail. (3% discount).
(C) In millions, adjusted for stock splits.
(D) Years prior to 1994 are not comparable due to acquisition using pooling of interest method.
(E) Atmos completed its merger with United Cities Gas Company in July, 1997.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	75
Earnings Predictability	80

ENERGEN CORP. NYSE-EGN

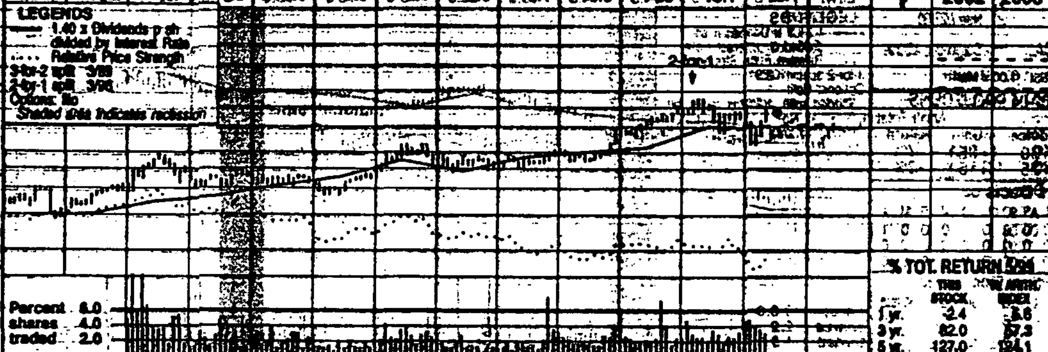
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
19	14.2	(Trailing: 15.7, Median: 13.0)	0.84	3.5%	472

TIMELINESS 4 Raised 5/7/99
SAFETY 2 New 7/27/90
TECHNICAL 4 Lowered 5/21/99
BETA .80 (1.00 = Market)

High:	9.6	12.2	10.3	9.4	9.6	13.4	11.9	12.6	15.6	20.6	22.5	19.9
Low:	8.2	7.7	8.0	8.0	7.5	9.1	9.6	10.1	10.9	14.5	15.1	13.1

Target Price Range 2002 2003 2004

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/89
2-for-1 split 3/98
Options: No
Shaded area indicates recession



2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+85%)	19%
Low	25	(+30%)	10%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	1	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	2Q1998	3Q1998	4Q1998
to Buy	63	49	45
to Sell	34	33	29
Hld's(000)	14467	14855	14903

Percent shares traded 6.0 4.0 2.0

% TOT. RETURN 5/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	-2.4	5.6
3 yr.	82.0	57.3
5 yr.	127.0	124.1

1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
33.08	34.39	29.89	28.54	25.06	22.75	15.92	16.45	16.11	16.30	17.30	17.27	14.72	17.89	15.57	17.14	16.35	16.65	Revenues per sh A	21.30
1.47	1.44	1.58	1.59	2.02	2.12	1.73	1.83	1.89	2.06	2.10	2.28	2.24	2.81	3.08	4.00	4.30	4.55	"Cash Flow" per sh	5.65
.53	.51	.47	.41	.70	.84	.60	.68	.71	.77	.89	1.01	.89	.98	1.16	1.23	1.30	1.40	Earnings per sh B	1.95
.28	.30	.33	.35	.37	.39	.42	.46	.48	.51	.53	.55	.57	.59	.61	.63	.65	.67	Div'ds Decl'd per sh C■	.75
1.28	1.49	2.72	3.32	3.33	2.58	3.07	2.12	2.32	1.11	2.12	2.09	3.16	7.54	9.84	6.95	8.85	6.25	Cap'l Spending per sh	4.70
4.48	4.68	4.83	4.85	5.02	5.59	5.84	6.10	6.04	6.38	6.80	7.65	7.97	8.44	10.46	11.23	13.10	14.15	Book Value per sh D	18.05
11.83	11.99	12.51	12.93	13.09	15.98	19.39	19.75	20.21	20.37	20.64	21.84	21.82	22.33	28.80	29.33	30.00	32.00	Common Shs Outst'g E	34.00
5.8	7.4	9.5	12.8	10.1	8.3	16.1	13.3	12.6	11.0	12.4	11.1	12.3	12.0	13.4	15.4	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	14.5
.49	.69	.77	.87	.68	.69	1.22	.99	.80	.67	.73	.73	.82	.75	.77	.81			Relative P/E Ratio	.95
9.1%	7.9%	7.2%	6.7%	5.2%	5.6%	4.4%	5.1%	5.4%	6.0%	4.8%	4.9%	5.2%	5.0%	3.9%	3.3%			Avg Ann'l Div'd Yield	2.7%

CAPITAL STRUCTURE as of 3/31/99
Total Debt $523.8 mill. Due in 5 Yrs $200.0 mill.
LT Debt $371.8 mill. LT Interest $26.5 mill.
(Total interest coverage: 2.0x)

Leases, Uncapitalized Annual rentals $3.9 mill.

Pension Liability None

Pfd Stock None

Common Stock 29,714,856 shs. as of 2/11/99

MARKET CAP: $575 million (Small Cap)

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		02-04
308.6	324.9	325.6	332.0	357.6	377.1	321.2	399.4	448.2	502.6	490	530	Revenues ($mill) A	725
11.2	13.3	14.2	15.8	18.2	21.8	19.3	21.5	29.0	36.3	39.5	45.0	Net Profit ($mill)	66.0
8.6%	8.9%	2.5%	2.4%	18.8%	22.7%	18.0%	19.0%	8.6%	8.8%	10.0%	15.0%	Income Tax Rate	20.0%
3.6%	4.1%	4.4%	4.8%	5.1%	5.8%	6.0%	5.4%	6.5%	7.2%	8.1%	8.5%	Net Profit Margin	9.1%
42.7%	40.4%	38.6%	40.8%	38.0%	41.5%	43.1%	50.9%	48.1%	53.1%	52.0%	52.0%	Long-Term Debt Ratio	50.0%
56.1%	58.7%	60.6%	58.4%	62.0%	58.5%	56.9%	49.1%	51.9%	46.9%	48.0%	48.0%	Common Equity Ratio	50.0%
201.9	205.2	201.6	222.3	228.2	286.3	305.5	384.0	580.7	702.0	820	940	Total Capital ($mill)	1220
246.6	262.2	273.5	254.6	273.1	287.2	327.3	444.9	682.0	756.3	930	1030	Net Plant ($mill)	1180
7.2%	8.3%	8.8%	9.1%	10.1%	9.5%	8.0%	7.1%	6.4%	6.8%	6.5%	6.5%	Return on Total Cap'l	7.0%
9.7%	10.9%	11.6%	12.0%	12.9%	12.1%	11.1%	11.4%	9.8%	11.0%	10.0%	10.0%	Return on Shr. Equity	11.0%
9.8%	10.9%	11.6%	12.1%	12.9%	13.1%	11.1%	11.4%	9.6%	11.0%	10.0%	10.0%	Return on Com Equity	11.0%
2.9%	3.7%	3.8%	4.2%	5.2%	6.0%	4.0%	4.6%	4.5%	5.5%	5.0%	5.0%	Retained to Com Eq	6.5%
70%	67%	68%	66%	60%	54%	64%	60%	53%	50%	50%	48%	All Div'ds to Net Prof	38%

CURRENT POSITION ($MILL.)	1997	1998	3/31/99
Cash Assets	105.4	103.2	11.0
Other	136.8	115.3	141.3
Current Assets	242.2	218.5	152.3
Accts Payable	49.2	33.5	31.1
Debt Due	203.9	160.2	152.0
Other	77.7	90.5	107.9
Current Liab.	330.8	284.2	290.9
Fix. Chg. Cov.	227%	205%	197%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	-4.0%	-.5%	2.0%
"Cash Flow"	6.5%	10.5%	9.0%
Earnings	5.5%	7.5%	8.0%
Dividends	5.0%	4.0%	3.5%
Book Value	7.0%	9.5%	10.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	78.8	171.0	87.1	62.5	399.4
1997	97.0	182.9	90.9	77.4	448.2
1998	125.8	198.0	100.7	78.1	502.6
1999	114.0	188.4	105	82.6	490
2000	125	205	110	90.0	530

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	[illegible]	.70	.06	.24	.98
1997	.14	1.21	.12	.29	1.16
1998	.21	1.37	[illegible]	.34	1.23
1999	.17	1.42	[illegible]	.29	1.30
2000	.17	1.44	.05	.26	1.40

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.14	.14	.145	.145	.57
1996	.145	.145	.15	.15	.59
1997	.15	.15	.155	.155	.61
1998	.155	.155	.16	.16	.63
1999	.16	.16			

BUSINESS: Energen Corporation is a holding company. Its principal subsidiary, the Alabama Gas Corporation, sells to more than 465,000 customers in central and northern Alabama, including Birmingham and Montgomery. 1998 utility revenues: residential, 65.4%; commercial and industrial, 24.2%; transport and other, 10.4%. 1998 deliveries: 115.3 MMcf. Energy Resources Corporation, a subsidiary, engages primarily in exploration and production of natural gas. 1998 gas reserves: coalbed methane, 222.5 MMcf; conventional, 542.4 MMcf. Has about 1,420 employees. Chairman, President & C.E.O.: Wm. Michael Warren, Jr. Inc.: AL. Addr.: 2101 6th Avenue North, Birmingham, AL 35203-2784. Tel.: 205-326-2700. Internet addr.: http://www.energen.com.

Energen should benefit nicely from the recent improvement in the near-term outlook for oil and gas prices. Indeed, this brightening picture is a departure from our somewhat negative, earlier view. Our revised commodity forecasts augur well for Energen Corporation's exploration and production (E&P) division, especially in light of the segment's healthy production volumes. Indeed, we have raised our fiscal 1999 and 2000 share-earnings estimates by $0.05 and $0.10, respectively. (Years end September 30th.)

The timing of Energen's accelerated gas and oil reserve acquisition efforts appears to be fortuitous. In the December quarter, the company paid approximately $135 million for the assets of TOTAL Minatome, its largest reserve purchase to date. In this transaction, Energen received roughly 209 billion cubic feet equivalent of proved oil and gas reserves. Such efforts give us greater confidence in the company meeting our share-net expectations out to fiscal 2000. Too, should the commodity spot market unexpectedly falter, the E&P business is afforded a good degree of protection by various price hedges currently in effect. Finally, the bottom line is also apt to receive a boost from nonconventional fuels tax credits related to certain E&P ventures. These positives will probably be offset to some extent, though, by added depreciation, depletion, amortization, and development expenses.

Stepped-up capital spending will likely require further external financing. We expect a common equity offering in the neighborhood of $50 million sometime in fiscal 2000. We have already adjusted our earnings model accordingly.

The gas distributor, meanwhile, ought to be a steady performer. The utility's Rate Stabilization and Equalization (RSE) mechanism should allow the unit to maintain its earnings and cash flow contribution. The RSE is specifically designed to allow the division to post a consistent return on equity between 13.15% to 13.65%.

Energen stock has risen sharply since our March review, most likely as a result of the healthier commodity markets. The dividend yield has come down somewhat, however, as the price has surged, and the stock remains untimely.

Oscar L. Vidal *June 25, 1999*

(A) Fiscal year ends September 30th.
(B) Primary egs thru '96, then diluted. Excl. nonrec. items: '96, d25¢; '92, 5¢; '94, 9¢. Excl. loss from disc. ops.: '89, 14¢. Next egs. report due late Jul.
(C) Next dividend meeting about Jul. 28. Goes ex about Aug. 15. Approx. div'd payment dates: March 1, June 1, Sept. 1, Dec. 1. ■ Dividend reinvestment plan available.
(D) Includes intang. assets: in '98, $18.7 mill.
(E) In mill., adjusted for stock splits.
(F) Quarters do not add to total due to change in shares outstanding.

Company's Financial Strength B++
Stock's Price Stability [illegible]
Price Growth Persistence [illegible]
Earnings Predictability [illegible]

ENERGEN CORP. NYSE-EGN

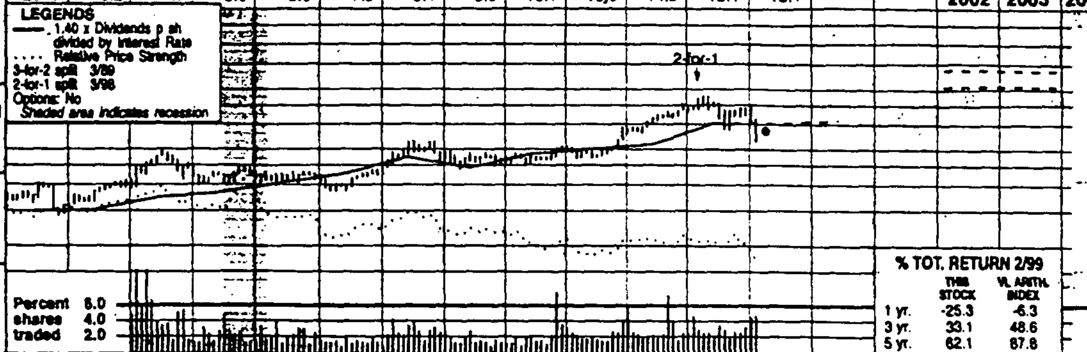
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
15	12.0	(Trailing: 12.9 / Median: 13.0)	0.[illegible]	4.4%	472

TIMELINESS 5 Lowered 2/5/99
SAFETY 2 New 7/27/90
TECHNICAL 3 Lowered 10/3/97
BETA .80 (1.00 = Market)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
High:	8.6	12.2	10.3	9.4	9.6	13.4	11.9	12.6	15.6	20.6	22.5	19.8
Low:	6.2	7.7	8.0	8.0	7.5	9.1	9.6	10.1	10.9	14.5	15.1	13.1

Target Price Range 2002 | 2003 | 2004

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/89
2-for-1 split 3/98
Options: No
Shaded area indicates recession



2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+100%)	22%
Low	25	(+65%)	17%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	2Q1998	3Q1998	4Q1998
to Buy	53	48	45
to Sell	34	33	29
Hld's(000)	14467	14655	14903

% TOT. RETURN 2/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	-25.3	-6.3
3 yr.	33.1	48.6
5 yr.	62.1	87.8

1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
33.08	34.39	29.89	28.54	25.06	22.75	15.92	16.45	16.11	16.30	17.30	17.27	14.72	17.89	15.57	17.14	15.70	15.90	Revenues per sh A	21.20
1.47	1.44	1.58	1.59	2.02	2.12	1.73	1.83	1.89	2.06	2.10	2.28	2.24	2.81	3.08	4.00	4.05	4.30	"Cash Flow" per sh	5.60
.53	.51	.47	.41	.70	.84	.60	.68	.71	.77	.89	1.01	.89	.98	1.16	1.23	1.25	1.30	Earnings per sh B	1.90
.28	.30	.33	.35	.37	.39	.42	.46	.48	.51	.53	.55	.57	.59	.61	.63	.65	.67	Div'ds Decl'd per sh C■	.75
1.28	1.49	2.72	3.32	3.33	2.58	3.07	2.12	2.32	1.11	2.12	2.09	3.16	7.54	9.84	5.95	8.25	6.05	Cap'l Spending per sh	4.70
4.48	4.68	4.83	4.65	5.02	5.59	5.84	6.10	6.04	6.38	6.80	7.65	7.97	8.44	10.46	11.23	12.45	13.55	Book Value per sh D	17.90
11.83	11.99	12.51	12.93	13.09	15.98	19.39	19.75	20.21	20.37	20.64	21.84	21.82	22.33	28.80	29.33	31.50	33.00	Common Shs Outst'g E	34.00
5.8	7.4	9.5	12.8	10.1	8.3	16.1	13.3	12.6	11.0	12.4	11.1	12.3	12.0	13.4	15.4	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.0
.49	.69	.77	.87	.68	.69	1.22	.99	.80	.67	.73	.73	.82	.75	.77	.81	estimates		Relative P/E Ratio	.95
9.1%	7.9%	7.2%	6.7%	5.2%	5.6%	4.4%	5.1%	5.4%	6.0%	4.8%	4.9%	5.2%	5.0%	3.9%	3.3%			Avg Ann'l Div'd Yield	2.8%

CAPITAL STRUCTURE as of 12/31/98
Total Debt $567.8 mill. Due in 5 Yrs $247.0 mill.
LT Debt $372.8 mill. LT Interest $26.5 mill.
(Total interest coverage: 1.9x)

Leases, Uncapitalized Annual rentals $3.9 mill.

Pension Liability None

Pfd Stock None
Common Stock 29,569,925 shs.
as of 2/11/99

MARKET CAP: $450 million (Small Cap)

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		02-04
308.6	324.9	325.6	332.0	357.1	377.1	321.2	399.4	448.2	502.6	495	525	Revenues ($mill) A	720
11.2	13.3	14.2	15.8	18.2	21.8	19.3	21.5	29.0	36.3	38.0	42.0	Net Profit ($mill)	65.0
8.6%	8.9%	2.5%	2.4%	15.8%	22.7%	16.0%	19.0%	9.6%	9.6%	10.0%	15.0%	Income Tax Rate	20.0%
3.6%	4.1%	4.4%	4.8%	5.1%	5.8%	6.0%	5.4%	6.5%	7.2%	7.7%	8.0%	Net Profit Margin	9.0%
42.7%	40.4%	38.6%	40.8%	38.0%	41.5%	43.1%	50.9%	48.1%	53.1%	52.5%	52.5%	Long-Term Debt Ratio	51.5%
56.1%	58.7%	60.6%	58.4%	62.0%	58.5%	56.9%	49.1%	51.9%	46.9%	47.5%	47.5%	Common Equity Ratio	48.5%
201.9	205.2	201.5	222.3	226.2	285.3	305.5	384.0	580.7	702.0	820	940	Total Capital ($mill)	1250
248.6	262.2	273.5	254.6	273.1	287.2	327.3	444.9	667.0	756.3	930	1030	Net Plant ($mill)	1180
7.2%	8.3%	8.8%	9.1%	10.1%	9.5%	8.3%	7.1%	6.4%	6.8%	6.5%	6.0%	Return on Total Cap'l	7.0%
9.7%	10.9%	11.5%	12.0%	12.9%	13.1%	11.1%	11.4%	9.6%	11.0%	9.5%	9.5%	Return on Shr. Equity	10.5%
9.8%	10.9%	11.6%	12.1%	12.9%	13.1%	11.1%	11.4%	9.6%	11.0%	9.5%	9.5%	Return on Com Equity	10.5%
2.9%	3.7%	3.8%	4.2%	5.2%	6.0%	4.0%	4.6%	4.5%	5.5%	4.5%	4.5%	Retained to Com Eq	6.5%
70%	67%	68%	66%	60%	54%	64%	60%	53%	50%	52%	52%	All Div'ds to Net Prof	39%

CURRENT POSITION ($MILL.)	1997	1998	12/31/98
Cash Assets	105.4	103.2	7.3
Other	136.8	115.3	159.0
Current Assets	242.2	218.5	166.3
Accts Payable	49.2	33.5	46.9
Debt Due	203.9	160.2	195.0
Other	77.7	90.5	119.0
Current Liab.	330.8	284.2	360.9
Fix. Chg. Cov.	227%	205%	188%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	-4.0%	.5%	2.0%
"Cash Flow"	5.5%	10.5%	9.0%
Earnings	5.5%	7.5%	9.0%
Dividends	5.0%	4.0%	3.5%
Book Value	7.0%	9.5%	10.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar. 31	Jun.30	Sep.30	Full Fiscal Year
1996	78.8	171.0	87.1	62.5	399.4
1997	97.0	182.9	90.9	77.4	448.2
1998	125.8	198.0	100.7	78.1	502.6
1999	114.0	190	105	86.0	495
2000	120	205	110	90.0	525

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	.11	1.07	.05	d.24	F.98
1997	.14	1.21	.12	d.29	F1.16
1998	.21	1.37	--	d.34	F1.23
1999	.13	1.35	.05	d.28	1.25
2000	.15	1.40	.05	d.30	1.30

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.14	.14	.145	.145	.57
1996	.145	.145	.15	.15	.59
1997	.15	.15	.155	.155	.61
1998	.155	.155	.16	.16	.63
1999	.16				

BUSINESS: Energen Corporation is a holding company. Its principal subsidiary, the Alabama Gas Corporation, sells to more than 465,000 customers in central and northern Alabama, including Birmingham and Montgomery. 1998 utility revenues: residential, 65.4%; commercial and industrial, 24.2%; transport and other, 10.4%. 1998 deliveries: 115.3 MMcf. Energy Resources Corporation, a subsidiary, engages primarily in exploration and production of natural gas. 1998 gas reserves: coalbed methane, 222.5 MMcf; conventional, 542.4 MMcf. Has about 1,420 employees. Chairman, President & C.E.O.: Wm. Michael Warren, Jr. Inc.: AL. Addr.: 2101 Sixth Avenue North, Birmingham, AL 35203-2784. Tel.: 205-326-2700. Internet addr.: http://www.energen.com.

We are lowering our fiscal-1999 share-earnings for Energen Corporation by a dime, to $1.25. (Year ends September 30th.) This adjustment stems mainly from adverse trends in the company's exploration and production (E&P) segment. Although some protection is afforded by hedges currently in place, the E&P arm has been hurt by lackluster natural gas and oil prices. Weak commodity markets have worked to offset the benefits of higher production volumes. Nonetheless . . .

Energen continues to aggressively pursue its reserve acquisition strategy. Last quarter, the company spent $130 million for its purchase of TOTAL Minatome, its largest to date. The company received approximately 200 billion cubic feet equivalent of proved oil and gas reserves. Such efforts, we believe, will substantially aid the drive towards higher share net in fiscal 2000, especially given our outlook for a recovery in oil and gas prices. Indeed, Energen has allocated a major portion of its capital spending budget to further reserve acquisitions and development. Moreover, the bottom line is apt to get a boost from nonconventional fuels tax credits related to certain E&P operations. This will likely be countered to some extent, however, by higher associated depreciation, depletion, amortization and development costs.

Extensive capital spending will probably necessitate additional external financing. Along these lines, Energen plans to offer roughly $50 million in common equity, split between this fiscal year and next. We have adjusted our model accordingly.

The utility, meantime, should contribute earnings stability. The gas distributor's Rate Stabilization and Equalization (RSE) mechanism should continue to provide a dependable cash stream. The RSE is designed to allow the utility to maintain a return on equity between 13.15% to 13.65%.

This stock has good risk-adjusted total-return prospects, with dividends, out to 2002-2004. Conservative investors should take notice of the equity's Safety rank of 2 (Above Average). The E&P business will likely help share-net growth over the 3- to 5-year horizon.

Oscar Vidal *March 26, 1999*

(A) Fiscal year ends September 30th.
(B) Primary egs thru. '96, then diluted. Excl. nonrec. items: '86, d25¢; '92, 5¢; '94, 9¢. Excl. [illegible] from disc. ops.: '89, 14¢. Next egs. rep't due late Apr. (C) Next dividend meeting about Apr. 26. Goes ex about May 15. Approx. dividend payment dates: March 1, June 1, Sept. 1, Dec. 1. ■ Dividend reinvestment plan available.
(D) Includes intang. assets. In '98: $18.7 mill., 64¢/sh. (E) In mill., adjusted for stock splits.
(F) Quarters do not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	70

NEW JERSEY RES. NYSE-NJR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
39	15.4	(Trailing: 15.8 Median: 14.0)	0.91	4.4%	478

TIMELINESS 4 Lowered 3/19/99
SAFETY 2 New 7/27/90
TECHNICAL 3 Lowered 4/30/99
BETA .80 (1.00 = Market)

2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+30%)	10%
Low	40	(+5%)	5%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	2	0	0	1	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

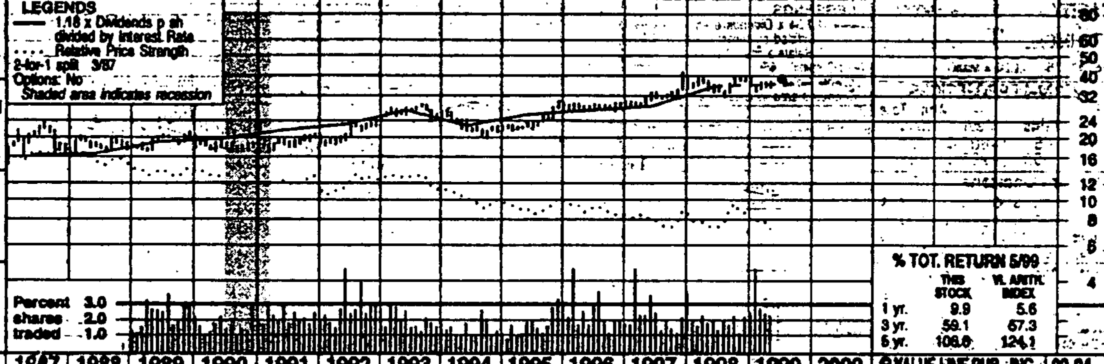
	2Q1998	3Q1998	4Q1998
to Buy	40	44	37
to Sell	21	15	28
Hld's(000)	6202	6358	6441

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
High:	20.6	21.5	20.9	21.1	25.1	29.5	27.4	30.5	29.9	42.1	40.3
Low:	16.8	17.1	17.1	17.0	18.3	24.0	19.8	21.5	26.6	28.1	31.5

High 40.1, Low 33.6

Target Price Range 2002 2003 2004

LEGENDS
— 1.18 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/87
Options: No
Shaded area indicates recession



% TOT. RETURN 5/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	9.9	5.6
3 yr.	59.1	67.3
5 yr.	106.6	124.1

1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
41.48	41.33	40.15	35.12	30.05	27.03	25.02	24.02	23.98	25.32	27.04	28.82	25.55	30.33	38.96	39.88	**44.60**	**46.05**	Revenues per sh A	**53.05**
2.20	2.96	2.90	2.34	2.70	2.63	2.46	2.31	2.36	2.93	3.20	3.46	3.20	3.33	3.68	3.91	**4.20**	**4.35**	"Cash Flow" per sh	**5.20**
1.10	1.59	1.35	.69	1.27	1.59	1.45	.97	.83	1.64	1.72	1.89	1.93	2.06	2.22	2.33	**2.50**	**2.70**	Earnings per sh B	**3.40**
.89	.97	1.06	1.13	1.20	1.28	1.36	1.44	1.50	1.52	1.52	1.52	1.52	1.55	1.60	1.64	**1.68**	**1.72**	Div'ds Decl'd per sh C■	**1.90**
4.55	6.03	5.86	6.93	7.84	7.84	6.56	6.55	4.36	2.99	3.46	3.15	2.66	2.67	2.58	2.41	**2.70**	**2.75**	Cap'l Spending per sh	**3.20**
8.52	9.26	8.78	8.61	10.73	12.40	13.64	13.27	12.85	14.16	14.72	14.46	14.55	15.15	15.57	16.33	**17.40**	**18.65**	Book Value per sh D	**23.45**
6.75	6.89	7.06	7.21	8.96	10.93	13.18	13.52	13.97	16.29	16.82	17.30	17.79	18.08	17.88	17.81	**18.05**	**18.25**	Common Shs Outst'g E	**18.85**
7.5	7.2	9.8	20.4	14.7	11.6	13.0	24.0	22.3	12.4	15.1	13.0	11.7	13.6	13.5	15.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**13.0**
.63	.67	.80	1.38	.98	.96	.98	1.78	1.42	.75	.89	.85	.78	.85	.78	.81			Relative P/E Ratio	**.85**
10.7%	8.5%	8.0%	8.0%	6.4%	6.9%	7.2%	6.2%	8.1%	7.5%	5.8%	6.2%	6.7%	5.6%	5.3%	4.6%			Avg Ann'l Div'd Yield	**4.3%**

CAPITAL STRUCTURE as of 3/31/99

Total Debt $375.5 mill. Due in 5 Yrs $156.0 mill.
LT Debt $319.4 mill. LT Interest $16.8 mill.
Incl. $.2 mill. capitalized leases.
(LT interest earned: 4.7x; total interest coverage: 4.1x)

Pension Liability None

Pfd Stock $.6 mill. Pfd Div'd $.05 mill.
$20 million, 7.72% issue redeemed 10/98.

Common Stock 17,915,549 shs. outstanding at 5/6/99

MARKET CAP: $700 million (Small Cap)

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		02-04
329.9	324.8	334.9	412.3	454.7	498.7	454.6	548.5	696.5	710.3	**805**	**840**	Revenues ($mill) A	**1000**
17.4	13.9	12.4	25.9	30.5	33.9	35.6	38.7	41.5	43.3	**47.0**	**49.0**	Net Profit ($mill)	**65.0**
31.3%	31.4%	31.1%	30.4%	28.3%	30.4%	31.0%	32.6%	33.3%	30.4%	**33.0%**	**33.0%**	Income Tax Rate	**33.0%**
5.3%	4.3%	3.7%	6.3%	6.7%	6.8%	7.8%	7.1%	6.0%	6.1%	**5.8%**	**5.8%**	Net Profit Margin	**6.5%**
51.9%	54.2%	55.3%	48.9%	53.5%	54.3%	55.7%	50.7%	49.3%	51.2%	**54.0%**	**53.0%**	Long-Term Debt Ratio	**50.5%**
44.7%	42.7%	37.8%	44.8%	42.6%	42.0%	41.0%	45.8%	47.1%	45.6%	**46.0%**	**47.0%**	Common Equity Ratio	**49.5%**
402.0	420.4	475.0	515.2	580.9	595.8	632.2	598.2	590.6	638.2	**680**	**725**	Total Capital ($mill)	**895**
463.1	533.3	567.0	592.2	632.6	640.4	598.1	655.2	658.4	680.0	**705**	**730**	Net Plant ($mill)	**815**
6.1%	5.8%	5.3%	7.4%	7.3%	7.5%	7.6%	8.1%	8.6%	8.1%	**8.5%**	**8.0%**	Return on Total Cap'l	**8.5%**
8.0%	7.2%	5.8%	9.8%	11.9%	12.5%	12.7%	13.1%	13.9%	13.9%	**15.0%**	**14.5%**	Return on Shr. Equity	**14.5%**
9.1%	7.2%	8.3%	10.2%	11.5%	12.9%	13.1%	13.5%	14.3%	14.4%	**14.5%**	**14.5%**	Return on Com Equity	**14.5%**
.9%	NMF	NMF	.8%	1.6%	2.6%	2.6%	3.4%	4.0%	4.4%	**5.0%**	**5.0%**	Retained to Com Eq	**6.5%**
91%	NMF	NMF	93%	87%	81%	79%	76%	73%	71%	**67%**	**63%**	All Div'ds to Net Prof	**56%**

CURRENT POSITION ($MILL.)	1997	1998	3/31/99
Cash Assets	5.5	2.5	11.8
Other	134.9	159.0	186.9
Current Assets	140.4	161.5	198.7
Accts Payable	28.6	29.7	22.0
Debt Due	48.1	62.7	56.1
Other	84.4	75.4	86.4
Current Liab.	161.1	167.8	164.5
Fix. Chg. Cov.	329%	338%	348%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	1.5%	7.5%	6.5%
"Cash Flow"	3.5%	6.0%	6.5%
Earnings	6.5%	9.5%	7.5%
Dividends	3.0%	1.0%	3.0%
Book Value	4.0%	2.5%	7.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	159.7	233.9	94.5	60.4	548.5
1997	188.6	285.4	121.1	101.4	696.5
1998	220.4	266.6	113.4	109.9	710.3
1999	244.6	327.3	*130*	*103.1*	*805*
2000	*270*	*320*	*140*	*110*	*840*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	.69	1.50	.12	d.25	2.06
1997	.72	1.58	.14	d.22	2.22
1998	.79	1.60	.16	d.22	2.33
1999	.84	1.69	*.17*	*d.20*	*2.50*
2000	*.88*	*1.80*	*.20*	*d.18*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.38	.38	.38	.38	1.52
1996	.38	.39	.39	.39	1.55
1997	.40	.40	.40	.40	1.60
1998	.41	.41	.41	.41	1.64
1999	.42	.42			

BUSINESS: New Jersey Resources Corp. is the holding company for New Jersey Natural Gas Co., a natural gas utility (385,188 customers at 9/30/98 in Monmouth, Ocean, and parts of other N.J. counties. Fiscal 1998 volume: 164.7 bill. cu. ft. (30% firm, 6% interruptible, industrial and electric utility, 64% off-system and capacity release). New Jersey Natural Energy subsid. provides unregulated retail and wholesale natural gas and related energy services to customers in 17 states. '98 deprec. rate: 3.1%. Est'd plant age: 8 years. Has 800 utility employees; 16,300 stockholders. Offcrs. & dir. own about 8% of common stock (1/99 Proxy). Chairman and President: Laurence M. Downes. Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 908-938-1480. Web: www.njresources.com.

Fiscal 1999 is shaping up as another strong year for New Jersey Resources. The main source of earnings growth is the core New Jersey Natural Gas subsidiary. Operating profits at the utility ran about 10% above the year-ago level during the all-important first half (Fiscal years end September 30th.)

The utility's success is driven by rapid customer growth. NJNG serves a central and southern New Jersey territory that is experiencing a high level of residential construction and also substantial conversion activity from oil to natural gas heating. Consequently, the utility is gaining about 12,000 hookups each year. **NJNG is showing improved efficiency.** The utility has reduced its work force by about 9% during the past two years, even while gaining customers. NJNG has substantially expanded its infrastructure during recent years. With the gas mains in place, the cost of adding customers has come down.

The company is taking advantage of opportunities outside its core business. NJNG is aggressively offering excess gas supplies "off-system," outside its territory. These volumes are up about 60% this year and now account for the majority of the utility's throughput. However, the utility is required to give 85% of the margin generated from this activity to its core, system customers. NJR is also working to increase the importance of nonregulated businesses in its revenue mix. The company has gotten out of the real estate management business and is instead concentrating on businesses related to its energy management expertise. NJR's wholesale natural gas sales and storage management business has grown by more than 40% this year. But the gas marketing business, which offers utility customers the option of choosing their own supplier, has been hurt by the elimination of a tax advantage.

This issue, though untimely, is suitable for income-oriented accounts. The stock offers an attractive yield. The steady earnings growth produced in recent years has enhanced the stock's Price Stability. Stockholders should also benefit from recent reductions in high-rate debt and preferred stock obligations.

Ben Sharav, CFA *June 25, 1999*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Next earnings report due late July. Excludes nonrec. gains (loss): '86, ($0.18); '88, $0.08; '94, $0.06.
(C) Next div'd meeting about August 10. Goes ex about September 14. Approx. div'd payment dates: 1st of Jan., Apr., July, Oct. ■ Dividend reinvestment plan available.
(D) Includes deferred charges. In 1998: $101.5 million, $5.70/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	85

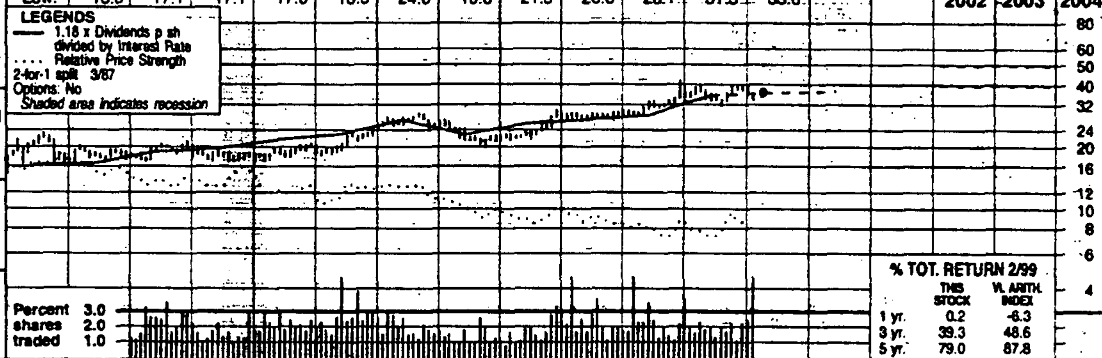
NEW JERSEY RES. NYSE-NJR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
37	14.8	(Trailing: 15.5 Median: 14.0)	0.92	4.6%	478

TIMELINESS 4 Lowered 3/19/99
SAFETY 2 New 7/27/90
TECHNICAL 3 Raised 12/5/97
BETA .55 (1.00 = Market)

High:	20.6	21.5	20.9	21.1	25.1	29.5	27.4	30.5	29.9	42.1	40.3	40.1
Low:	16.8	17.1	17.1	17.0	18.3	24.0	19.8	21.5	26.6	28.1	31.5	33.6

Target Price Range 2002 2003 2004



2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+35%)	12%
Low	40	(+10%)	7%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	2	0	0	1	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q1998	3Q1998	4Q1998
to Buy	40	44	37
to Sell	21	15	28
Hld's(000)	6202	6358	6441

% TOT. RETURN 2/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	0.2	-6.3
3 yr.	39.3	48.6
5 yr.	79.0	87.8

1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
41.48	41.33	40.15	35.12	30.05	27.03	25.02	24.02	23.98	25.32	27.04	28.82	25.55	30.33	38.96	39.88	42.40	44.40	Revenues per sh A	51.20
2.20	2.96	2.90	2.34	2.70	2.63	2.46	2.31	2.36	2.93	3.20	3.46	3.20	3.33	3.68	3.91	4.10	4.35	"Cash Flow" per sh	5.25
1.10	1.59	1.35	.69	1.27	1.59	1.45	.97	.83	1.64	1.72	1.89	1.93	2.06	2.22	2.33	2.50	2.65	Earnings per sh B	3.40
.89	.97	1.06	1.13	1.20	1.28	1.36	1.44	1.50	1.52	1.52	1.52	1.52	1.55	1.60	1.64	1.68	1.72	Div'ds Decl'd per sh C■	1.90
4.55	6.03	5.86	6.93	7.84	7.84	6.56	6.55	4.36	2.99	3.46	3.15	2.66	2.67	2.58	2.41	2.55	2.70	Cap'l Spending per sh	3.10
8.52	9.26	8.78	8.61	10.73	12.40	13.64	13.27	12.85	14.16	14.72	14.46	14.55	15.15	15.57	16.33	17.40	18.60	Book Value per sh D	23.45
6.75	6.89	7.06	7.21	8.96	10.93	13.18	13.52	13.97	16.29	16.82	17.30	17.79	18.08	17.88	17.81	18.05	18.25	Common Shs Outst'g E	18.85
7.5	7.2	9.8	20.4	14.7	11.6	13.0	24.0	22.3	12.4	15.1	13.0	11.7	13.6	13.5	15.3	Bold figures are		Avg Ann'l P/E Ratio	13.0
.63	.67	.80	1.38	.98	.96	.98	1.78	1.42	.75	.89	.85	.78	.85	.78	.81	Value Line		Relative P/E Ratio	.85
10.7%	8.5%	8.0%	8.0%	6.4%	6.9%	7.2%	6.2%	8.1%	7.5%	5.8%	6.2%	6.7%	5.6%	5.3%	4.6%	estimates		Avg Ann'l Div'd Yield	4.3%

CAPITAL STRUCTURE as of 12/31/98

Total Debt $428.5 mill. Due in 5 Yrs $156.0 mill.
LT Debt $333.5 mill. LT Interest $16.8 mill.
Incl. $.2 mill. capitalized leases.
(LT interest earned: 4.7x; total interest coverage: 4.1x)
Pension Liability None

Pfd Stock $.6 mill. Pfd Div'd $.05 mill.
$20 million, 7.72% issue redeemed 10/98.
Common Stock 17,895,018 shs. outstanding at 2/5/99
MARKET CAP: $650 million (Small Cap)

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		02-04
329.9	324.8	334.9	412.3	454.7	498.7	454.6	548.5	696.5	710.3	765	810	Revenues ($mill) A	965
17.4	13.9	12.4	25.9	30.5	33.9	35.6	38.7	41.5	43.3	46.0	49.0	Net Profit ($mill)	65.0
31.3%	31.4%	31.1%	30.4%	29.3%	30.4%	31.0%	32.6%	33.3%	30.4%	33.0%	33.0%	Income Tax Rate	33.0%
5.3%	4.3%	3.7%	6.3%	6.7%	6.8%	7.8%	7.1%	6.0%	6.1%	6.0%	6.0%	Net Profit Margin	6.7%
51.9%	54.2%	55.3%	48.9%	53.5%	54.3%	55.7%	50.7%	49.3%	51.2%	52.5%	52.0%	Long-Term Debt Ratio	49.5%
44.7%	42.7%	37.8%	44.8%	42.6%	42.0%	41.0%	45.8%	47.1%	45.6%	47.0%	48.0%	Common Equity Ratio	50.5%
402.0	420.4	475.0	515.2	580.9	595.8	632.2	598.2	590.6	638.2	665	710	Total Capital ($mill)	880
463.1	533.3	587.0	592.2	632.6	640.4	596.1	655.2	659.4	680.0	700	725	Net Plant ($mill)	810
6.1%	5.8%	5.3%	7.4%	7.3%	7.5%	7.6%	8.1%	8.6%	8.1%	8.5%	8.5%	Return on Total Cap'l	8.5%
9.0%	7.2%	5.8%	9.8%	11.3%	12.5%	12.7%	13.1%	13.9%	13.9%	14.5%	14.5%	Return on Shr. Equity	14.5%
9.1%	7.2%	6.3%	10.2%	11.5%	12.9%	13.1%	13.5%	14.3%	14.4%	14.5%	14.5%	Return on Com Equity	14.5%
.9%	NMF	NMF	.8%	1.8%	2.6%	2.8%	3.4%	4.0%	4.4%	5.0%	5.0%	Retained to Com Eq	6.5%
91%	NMF	NMF	93%	87%	81%	79%	78%	73%	71%	67%	64%	All Div'ds to Net Prof	55%

CURRENT POSITION ($MILL.)	1997	1998	12/31/98
Cash Assets	5.5	2.5	7.3
Other	134.9	159.0	209.4
Current Assets	140.4	161.5	216.7
Accts Payable	28.6	29.7	18.2
Debt Due	48.1	62.7	95.0
Other	84.4	75.4	116.9
Current Liab.	161.1	167.8	230.1
Fix. Chg. Cov.	329%	338%	340%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	1.5%	7.5%	6.0%
"Cash Flow"	3.5%	5.0%	7.0%
Earnings	6.5%	9.5%	7.5%
Dividends	3.0%	1.0%	3.0%
Book Value	4.0%	2.5%	7.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	159.7	233.9	94.5	60.4	548.5
1997	188.6	285.4	121.1	101.4	696.5
1998	220.4	266.6	113.4	109.9	710.3
1999	244.6	290.4	130	100	765
2000	260	305	140	105	810

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	.68	1.50	.12	d.25	2.06
1997	.72	1.58	.14	d.22	2.22
1998	.79	1.60	.16	d.22	2.33
1999	.84	1.67	.18	d.19	2.50
2000	.87	1.80	.20	d.22	2.65

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.38	.38	.38	.38	1.52
1996	.38	.39	.39	.39	1.55
1997	.40	.40	.40	.40	1.60
1998	.41	.41	.41	.41	1.64
1999	.42				

BUSINESS: New Jersey Resources Corp. is the holding company for New Jersey Natural Gas Co., a natural gas utility (385,188 customers at 9/30/98 in Monmouth, Ocean, and parts of other N.J. counties. Fiscal 1998 volume: 184.7 bill. cu. ft. (30% firm, 8% interruptible industrial and electric utility, 64% off-system and capacity release). New Jersey Natural Energy subsid. provides unregulated retail and wholesale natural gas and related energy services to customers in 17 states. '98 deprec. rate: 3.1%. Est'd plant age: 8 years. Has 800 utility employees, 16,300 stockholders. Offcrs. & dir. own about 8% of common stock (1/99 Proxy). Chairman and President: Laurence M. Downes. Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 908-938-1480. Web: www.njresources.com.

New Jersey Resources' gas utility stands out from the pack. New Jersey Natural Gas serves a central New Jersey territory that is experiencing rapid development. These new residential units choose gas energy at an overwhelming rate. In addition, the territory has a substantial number of units that use electric heating, and which are being given incentives to convert to lower-cost gas. Consequently, NJNG is adding more than 11,000 customers a year—about 60% new and 40% conversions—marking a growth pace well in excess of the national average.

NJNG has improved its efficiency. In the past, new hookups tended to require substantial capital investment. This was a major reason that NJR's earnings tended to move erratically. But now, with a larger system of gas mains in place, NJNG is able to add customers more easily. The cost of a new hookup has fallen some 30% in six years. NJNG has also streamlined its operations. The employee count has been reduced by 9% in the last two years.

The utility is benefiting from a weather normalization clause. Although the weather was 11% warmer than normal (in terms of utility degree-days) in fiscal 1998, the rate adjustment allowed NJR to post record profits. The mechanism is also working in the utility's favor in 1999. We expect share net to reach $2.50 for the year.

A state tax change has taken some of the impetus out of gas marketing. Previously, gas marketers were able to avoid the gross receipts tax that was imposed only on utility sales. Now the two methods of distribution are being taxed equally. This will likely trim the profits from NJR's marketing unit, but could ultimately result in a shakeout of gas marketers, to the benefit of the company.

NJR is still making advances on the nonregulated side. The utility aggressively sells gas "off system" in markets outside its territory. NJR Energy Holdings is also enjoying sharply higher revenues from its several unregulated energy services businesses.

This untimely stock offers an attractive dividend yield and is suitable for conservative investors with a 3- to 5-year time horizon.

Ben Sharav, CFA *March 26, 1999*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Next earnings report due late April. Excludes nonrec. gains (loss): '86, ($0.18); '88, $0.06; '94, $0.08.
(C) Next div'd meeting about May 10. Goes ex about June 14. Approx. div'd payment dates: 1st of Jan., Apr., July, Oct. ■ Dividend reinvestment plan available.
(D) Includes deferred charges. In 1998: $101.5 million, $5.70/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	85

LACLEDE GAS NYSE-LG

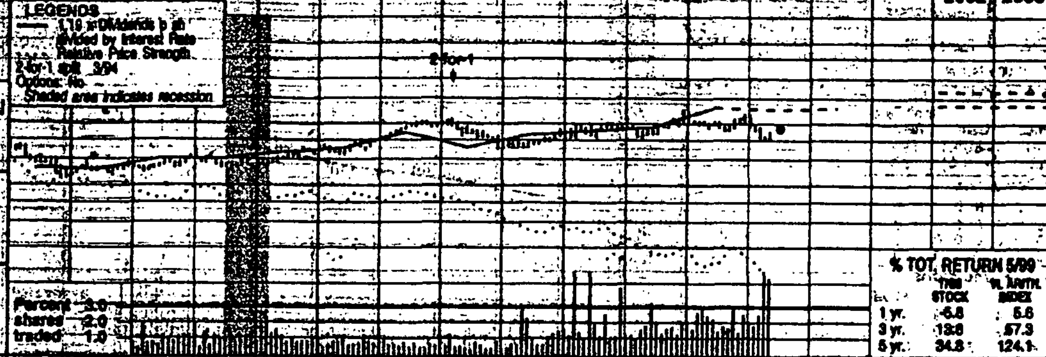
RECENT PRICE 23 | P/E RATIO 13.9 (Trailing: 15.8; Median: 14.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 5.9% | VALUE LINE 475

TIMELINESS 4 Lowered 5/7/99
SAFETY 1 New 7/27/90
TECHNICAL 4 Lowered 6/18/99
BETA .50 (1.00 = Market)

High: 15.9 17.0 18.0 18.7 20.5 24.9 25.8 23.1 24.9 28.6 27.9 27.0
Low: 18.5 14.0 14.2 14.9 16.9 20.0 18.3 18.4 20.0 20.3 22.4 20.0

Target Price Range 2002 2003 2004

LEGENDS
1.10 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 3/94
Options: No
Shaded area indicates recession



2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+50%)	15%
Low	30	(+30%)	12%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q1998	3Q1998	4Q1998
to Buy	29	22	31
to Sell	16	24	17
Hld's(000)	5894	6089	5943

Percent shares traded 3.0 2.0 1.0

% TOT. RETURN 5/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	-6.8	5.6
3 yr.	13.8	57.3
5 yr.	34.8	124.1

1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
37.29	38.64	35.36	34.89	28.38	30.82	31.57	30.21	28.10	28.83	32.33	33.43	24.79	31.03	34.33	31.04	26.05	29.50	Revenues per sh A	37.90
4.37	2.71	2.62	2.95	2.44	2.51	2.47	2.13	2.37	2.32	2.81	2.65	2.55	3.29	2.32	3.02	2.50	3.00	"Cash Flow" per sh	3.65
1.96	1.70	1.84	1.87	1.44	1.57	1.45	1.08	1.28	1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.35	1.80	Earnings per sh A B	2.25
.65	.75	.86	.95	1.06	1.10	1.15	1.18	1.20	1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.36	Div'ds Decl'd per sh C ■	1.45
1.01	1.10	1.31	1.56	1.53	1.92	1.82	1.87	2.46	2.87	2.62	2.50	2.63	2.35	2.44	2.68	2.35	2.40	Cap'l Spending per sh	2.65
8.17	9.12	9.92	10.54	10.98	11.44	11.74	11.75	11.83	11.79	12.19	12.44	13.05	13.72	14.26	14.57	14.90	15.45	Book Value per sh D	17.65
17.45	17.45	17.45	15.74	15.74	15.68	15.59	15.59	15.59	15.59	15.59	15.67	17.42	17.56	17.56	17.63	19.00	19.00	Common Shs Outst'g E	19.00
6.7	5.0	7.1	8.8	11.0	9.2	10.3	14.6	12.5	15.8	13.5	16.4	15.5	11.9	12.5	15.5	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.5
.57	.47	.58	.60	.74	.76	.78	1.08	.80	.96	.80	1.08	1.04	.75	.72	.81	estimates		Relative P/E Ratio	.95
10.1%	8.8%	7.3%	5.8%	6.7%	7.6%	7.7%	7.5%	7.5%	6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%			Avg Ann'l Div'd Yield	4.5%

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		02-04
492.2	470.8	438.1	418.2	504.0	523.9	431.9	544.8	602.8	547.2	495	560	Revenues ($mill) A	720
22.7	16.9	20.0	18.3	25.2	22.2	20.9	32.8	32.5	27.9	25.0	34.0	Net Profit ($mill)	43.0
27.4%	28.5%	35.1%	31.2%	37.3%	36.0%	32.1%	35.9%	36.1%	35.6%	36.5%	36.5%	Income Tax Rate	36.5%
4.6%	3.6%	4.6%	4.4%	5.0%	4.2%	4.8%	6.0%	5.4%	5.1%	5.1%	6.1%	Net Profit Margin	6.0%
38.7%	41.2%	46.9%	44.1%	46.3%	43.9%	40.2%	42.5%	38.0%	40.9%	40.0%	40.5%	Long-Term Debt Ratio	40.0%
60.6%	58.1%	52.5%	55.3%	53.1%	55.5%	59.3%	57.1%	61.6%	58.6%	59.5%	59.0%	Common Equity Ratio	59.5%
302.0	314.9	351.1	332.4	357.6	351.1	383.5	422.2	406.8	438.0	475	490	Total Capital ($mill)	560
302.4	316.3	339.3	367.3	390.8	411.7	434.3	452.2	467.6	490.6	515	540	Net Plant ($mill)	610
9.3%	7.3%	7.8%	7.6%	9.1%	8.1%	7.1%	9.4%	9.7%	8.1%	7.0%	8.5%	Return on Total Cap'l	9.0%
12.3%	9.1%	10.8%	9.8%	13.1%	11.3%	9.1%	13.5%	12.9%	10.8%	9.0%	11.5%	Return on Shr. Equity	12.5%
12.4%	9.2%	10.8%	9.9%	13.2%	11.3%	9.2%	13.6%	12.9%	10.8%	9.0%	12.0%	Return on Com Equity	13.0%
2.6%	NMF	.7%	NMF	3.3%	1.8%	.4%	4.5%	3.9%	1.8%	Nil	3.0%	Retained to Com Eq	4.5%
79%	110%	93%	103%	75%	86%	96%	67%	70%	83%	99%	76%	All Div'ds to Net Prof	65%

CAPITAL STRUCTURE as of 3/31/99

Total Debt $265.3 mill. Due in 5 Yrs $110.0 mill.
LT Debt $179.3 mill. LT Interest $13.5 mill.
(LT interest earned: 3.9x; total interest coverage: 2.9x)

Leases, Uncapitalized $.8 mill.
Pension Liability None

Pfd Stock $2.0 mill. Pfd Div'd $.1 mill.
Common Stock 17,627,987 shs. as of 4/22/99
MARKET CAP: $400 million (Small Cap)

CURRENT POSITION ($MILL.)	1997	1998	3/31/99
Cash Assets	4.5	3.7	9.6
Other	134.8	132.3	141.7
Current Assets	139.3	136.0	151.3
Accts Payable	29.6	20.7	26.3
Debt Due	99.0	98.5	86.0
Other	55.8	64.5	56.4
Current Liab.	184.4	183.7	168.7
Fix. Chg. Cov.	351%	287%	263%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	--	2.0%	3.0%
"Cash Flow"	2.0%	5.0%	2.0%
Earnings	1.0%	5.5%	4.0%
Dividends	2.0%	-1.5%	2.0%
Book Value	2.5%	3.5%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	155.0	246.6	86.0	57.2	544.8
1997	193.9	264.0	84.2	60.7	602.8
1998	199.7	213.8	77.2	56.5	547.2
1999	149.7	207.0	80.0	58.3	495
2000	185	220	90.0	65.0	560

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	.90	1.37	d.02	d.38	1.87
1997	.92	1.22	.04	d.34	1.84
1998	.78	1.04	d.05	d.19	1.58
1999	.55	1.14	d.03	d.31	1.35
2000	.85	1.25	d.05	d.25	1.80

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.31	.31	.31	.31	1.24
1996	.315	.315	.315	.315	1.26
1997	.325	.325	.325	.325	1.30
1998	.33	.33	.33	.33	1.32
1999	.33	.335			

BUSINESS: Laclede Gas Company is a regulated utility that distributes natural gas in eastern Missouri (population, 2 million), including the city of St. Louis, St. Louis County, and parts of 8 other counties. Had 615,907 customers at 9/98. Therms sold and transported in fisc. '98: 1.12 bill. Revenue mix: residential, 67%; commercial and industrial, 24%; transportation, 2%; other, 7%. Purch. gas accts. for 57% of rev. Oper. underground gas storage fields. Est'd plant age: 13.5 yrs. Has abt. 2,065 empl.; 9,715 common stckhdrs. Off. & dir. own less than 1% of common; Stupp Bros., 6.6% (12/98 Proxy). Chrmn., C.E.O. and Pres.: Douglas H. Yaeger. Inc.: MO. Address: 720 Olive Street, St. Louis, MO 63101. Tel.: 314-342-0500. Internet address: www.lacledegas.com

Laclede Gas Company's fiscal 1999 (ends September 30th) share earnings will likely fall short of the year-ago level. Although December-quarter temperatures in the utility's service areas were 7% colder than the prior-year period, they were still 8% warmer than normal. This performance came on the heels of a first fiscal quarter that was hampered even more by unfavorable climate. These trends are apt to have a substantial bottom-line impact, given the gas distributor's lack of weather-normalization adjustment mechanisms on rates. As a result, given that the third and fourth quarters are typically loss periods, share net will probably finish the year at about $1.35. However . . .

Assuming, as we do, normal temperatures going forward, share income may well recover in fiscal 2000. Meter additions, albeit below the gas distribution industry average, should contribute to the bottom line. Furthermore, we believe that the company will receive an extension on its Gas Supply Incentive Plan, which allows the utility and its customers to share in gains and losses arising from the management of gas supply purchases. Indeed, in the first half of this fiscal year, the company has benefited by $2.0 million in terms of pretax income.

Laclede has a rate case pending with the Missouri Public Service Commission. The utility requested a $30.5 million increase in annual rates. At this point we remain uncertain as to the ultimate outcome of this proceeding, on which the commission has until December to act.

This equity's Timeliness rank has come down one step, to 4 (Below Average). We attribute the change to weaker-than-anticipated recent share-earnings momentum. Appreciation prospects out to 2002-2004 are pretty good for a utility, though.

This issue's primary investment merit lies in its dividend. The current yield significantly exceeds the gas distribution industry mean of approximately 4.6%. We only expect modest increases in payments in coming years, though, given projected cash-flow levels. Conservative, income-oriented accounts ought to take notice of the stock's Safety rank of 1 (Highest).

Oscar L. Vidal *June 25, 1999*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Quarterly earnings may not add to total due to changes in shares outstanding. Next earnings report due late July.
(C) Next dividend meeting about Aug. 28. Goes ex about Sep. 9. Approx. dividend payment dates: 1st of January, April, July, October.
■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '98: $110.7 mill., $6.28/sh. (E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	60

LACLEDE GAS NYSE-LG

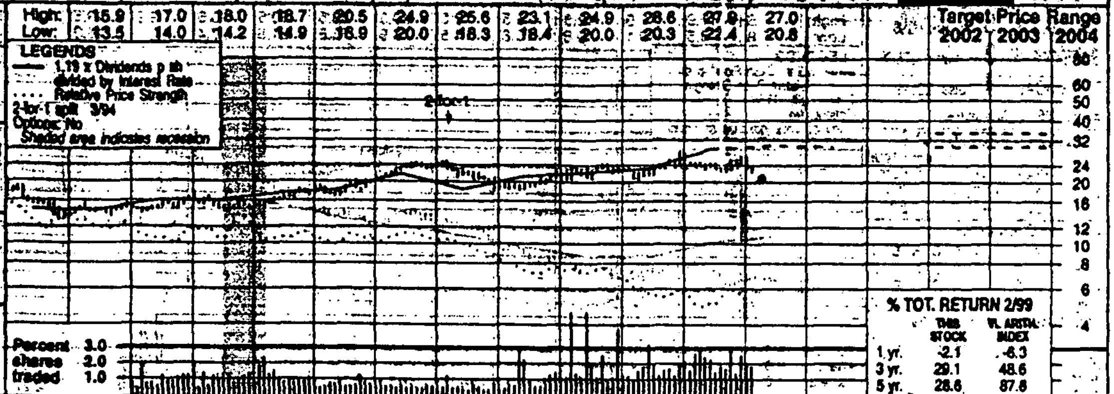
RECENT PRICE 21 | P/E RATIO 15.6 (Trailing: 15.1; Median: 14.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 6.5% | VALUE LINE 475

TIMELINESS 3 Raised 10/23/98
SAFETY 1 New 7/27/90
TECHNICAL 3 Raised 11/20/98
BETA .55 (1.00 = Market)

High:	15.9	17.0	18.0	18.7	20.5	24.9	25.6	23.1	24.9	28.6	27.9	27.0
Low:	13.5	14.0	14.2	14.9	16.9	20.0	18.3	18.4	20.0	20.3	22.4	20.6

Target Price Range 2002 2003 2004

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
··· Relative Price Strength
2-for-1 split 3/94
Options: No
Shaded area indicates recession



2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+65%)	18%
Low	30	(+45%)	14%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q1998	3Q1998	4Q1998
to Buy	29	22	31
to Sell	16	24	17
Hld's(000)	5894	6089	5943

Percent shares traded 3.0 2.0 1.0

% TOT. RETURN 2/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	-2.1	-6.3
3 yr.	29.1	48.6
5 yr.	28.6	87.6

1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
37.29	38.64	35.36	34.89	28.38	30.82	31.57	30.21	28.10	26.83	32.33	33.43	24.79	31.03	34.33	31.04	30.25	33.70	Revenues per sh A	41.10
1.97	2.71	2.62	2.95	2.44	2.51	2.47	2.13	2.37	2.32	2.81	2.65	2.55	3.29	3.32	3.02	2.80	3.10	"Cash Flow" per sh	3.75
1.96	1.70	1.64	1.87	1.44	1.57	1.45	1.08	1.28	1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.35	1.80	Earnings per sh A B	2.25
.85	.75	.85	.85	1.06	1.10	1.15	1.18	1.20	1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.36	Div'ds Decl'd per sh C ■	1.45
1.01	1.10	1.31	1.56	1.53	1.92	1.82	1.87	2.46	2.87	2.62	2.50	2.63	2.35	2.44	2.68	2.55	2.60	Cap'l Spending per sh	2.80
8.17	9.12	9.92	10.54	10.98	11.44	11.74	11.75	11.83	11.79	12.19	12.44	13.05	13.72	14.26	14.57	14.70	15.10	Book Value per sh D	17.10
17.45	17.45	17.45	15.74	15.74	15.68	15.59	15.59	15.59	15.59	15.59	15.67	17.42	17.56	17.56	17.63	17.70	17.80	Common Shs Outst'g E	18.00
16.7	5.0	7.1	8.8	11.0	9.2	10.3	14.6	12.5	15.8	13.5	16.4	15.5	11.9	12.5	15.5	Bold figures are		Avg Ann'l P/E Ratio	15.0
.57	.47	.58	.60	.74	.76	.78	1.08	.80	.96	.80	1.08	1.04	.75	.72	.81	Value Line		Relative P/E Ratio	1.00
10.1%	8.8%	7.3%	5.8%	6.7%	7.6%	7.7%	7.5%	7.5%	6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	estimates		Avg Ann'l Div'd Yield	4.3%

CAPITAL STRUCTURE as of 12/31/98

Total Debt $315.4 mill. Due in 5 Yrs $160.0 mill.
LT Debt $179.3 mill. LT Interest $13.5 mill.
(LT interest earned: 3.6x; total interest coverage: 2.7x)

Leases, Uncapitalized $.8 mill.
Pension Liability None

Pfd Stock $2.0 mill. Pfd Div'd $.1 mill.
Common Stock 17,627,987 shs. as of 2/11/99
MARKET CAP: $375 million (Small Cap)

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		02-04
492.2	470.8	438.1	418.2	504.0	523.9	431.9	544.8	602.8	547.2	535	600	Revenues ($mill) A	740
22.7	16.9	20.0	18.3	25.2	22.2	20.9	32.8	32.5	27.9	24.0	32.0	Net Profit ($mill)	41.0
27.4%	28.5%	35.1%	31.2%	37.3%	36.0%	32.1%	35.9%	36.1%	35.6%	36.0%	36.0%	Income Tax Rate	36.0%
4.6%	3.6%	4.6%	4.4%	5.0%	4.2%	4.8%	6.0%	5.4%	5.1%	4.5%	5.3%	Net Profit Margin	5.5%
38.7%	41.2%	46.9%	44.1%	46.3%	43.9%	40.2%	42.5%	38.0%	40.9%	42.0%	42.5%	Long-Term Debt Ratio	42.0%
60.6%	58.1%	52.5%	55.3%	53.1%	55.5%	59.3%	57.1%	61.6%	58.6%	57.5%	57.0%	Common Equity Ratio	57.5%
302.0	314.9	351.1	332.4	357.6	351.1	383.5	422.2	406.8	438.0	450	470	Total Capital ($mill)	530
302.4	316.3	339.3	367.3	390.8	411.7	434.3	452.2	467.6	490.6	510	540	Net Plant ($mill)	610
9.3%	7.3%	7.8%	7.6%	9.1%	8.1%	7.1%	9.4%	9.7%	8.1%	7.0%	8.5%	Return on Total Cap'l	9.0%
12.3%	9.1%	10.8%	9.8%	13.1%	11.3%	9.1%	13.5%	12.9%	10.8%	9.0%	12.0%	Return on Shr. Equity	13.5%
12.4%	9.2%	10.8%	9.9%	13.2%	11.3%	9.2%	13.6%	12.9%	10.8%	9.5%	12.0%	Return on Com Equity	13.5%
2.6%	NMF	.7%	NMF	3.3%	1.6%	.4%	4.5%	3.9%	1.8%	Nil	3.0%	Retained to Com Eq	5.0%
79%	110%	93%	103%	75%	86%	96%	67%	70%	83%	99%	76%	All Div'ds to Net Prof	64%

CURRENT POSITION ($MILL.)	1997	1998	12/31/98
Cash Assets	4.5	3.7	5.7
Other	134.8	132.3	180.0
Current Assets	139.3	136.0	185.7
Accts Payable	29.6	20.7	33.9
Debt Due	99.0	98.5	136.2
Other	55.8	64.5	52.2
Current Liab.	184.4	183.7	222.3
Fix. Chg. Cov.	351%	287%	254%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	--	2.0%	4.0%
"Cash Flow"	2.0%	5.0%	2.5%
Earnings	1.0%	5.5%	4.0%
Dividends	2.0%	1.5%	2.0%
Book Value	2.5%	3.5%	3.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	155.0	246.6	86.0	57.2	544.8
1997	193.9	264.0	84.2	60.7	602.8
1998	199.7	213.8	77.2	56.5	547.2
1999	149.7	240	85.0	60.3	535
2000	195	250	90.0	65.0	600

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
1996	.90	1.37	d.02	d.38	1.87
1997	.92	1.22	.04	d.34	1.84
1998	.78	1.04	d.05	d.19	1.58
1999	.55	1.20	d.05	d.35	1.35
2000	.90	1.25	d.05	d.30	1.80

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.31	.31	.31	.31	1.24
1996	.315	.315	.315	.315	1.26
1997	.325	.325	.325	.325	1.30
1998	.33	.33	.33	.33	1.32
1999	.33	.335			

BUSINESS: Laclede Gas Company is a regulated utility that distributes natural gas in eastern Missouri (population, 2 million), including the city of St. Louis, St. Louis County, and parts of 8 other counties. Had 615,907 customers at 9/98. Therms sold and transported in fisc. '98: 1.12 bill. Revenue mix: residential, 67%; commercial and industrial, 24%; transportation, 2%; other, 7%. Purch. gas accts. for 57% of rev. Oper. underground gas storage fields. Est'd plant age: 13.5 yrs. Has abt. 2,065 empl.; 9,715 common stkhdrs. Off. & dir. own less than 1% of common; Stupp Bros., 6.6% (12/98 Proxy). Chmn., C.E.O. and Pres.: Douglas H. Yaeger. Inc.: MO. Address: 720 Olive Street, St. Louis, MO 63101. Tel.: 314-342-0500. Internet address: www.lacledegas.com

Laclede will likely post a negative share-earnings comparison in fiscal 1999 (ends September 30th). The December quarter will likely take the blame for the full-year shortfall. In this period, temperatures in Laclede's service territories were 14% warmer than normal and 20% warmer year to year. Such trends have a tremendous impact on a company such as this that lacks weather normalization mechanisms on rates. Gas delivery volumes are substantially reduced. However . . .

Share net ought to recover in fiscal 2000, assuming, as we do, normal temperatures going forward. The company has done a decent job in keeping its operating expenses under control. Customer growth, while below the national average, will probably help the bottom line a bit, as well. Too, Laclede's Gas Supply Incentive Plan continues to perform well. This program allows the utility and its customers to share in gains and losses associated with the management of gas supply purchases.

In January, Laclede filed a request with the Missouri Public Service Commission for an increase in annual rates of $30.5 million. We are quite unsure as to how these proceedings will turn out. Our greatest concern revolves around a filing from less than a year ago, in which the regulatory board recommended a lowering of rates rather than the requested increase. On a positive note, though, in this instance the company was granted cuts in depreciation rates and favorable accounting treatment for pension costs. The commission has 11 months to act on the latest filing. It is possible that Laclede will settle before then.

This equity's dividend is quite attractive at today's depressed stock price levels. The quotation dipped understandably following disappointing December quarter share income. As a result, the yield significantly exceeds the gas distribution industry mean. And we expect continued modest increases in payments in coming years, considering Laclede's healthy balance sheet (from a utility standpoint). Conservative, income-oriented accounts may well find the issue's Safety rank of 1 (Highest) of particular appeal.

Oscar Vidal *March 26, 1999*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Quarterly earnings may not add to total due to changes in shares outstanding. Next earnings report due late Apr.
(C) Next dividend meeting about May 28. Goes ex about Jun. 9. Approx. dividend payment dates: 1st of January, April, July, October.
■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '98: $110.7 mill., $6.28/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	60

PIEDMONT NAT'L. NYSE-PNY

RECENT PRICE 32 | P/E RATIO 16.1 (Trailing: 16.8 Median: 14.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 4.4% | VALUE LINE 483

TIMELINESS 5 Lowered 6/11/99

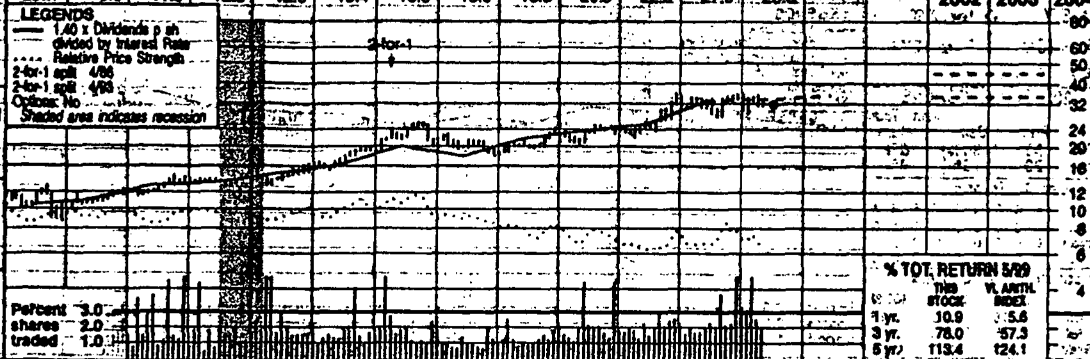
SAFETY 2 New 7/27/90

TECHNICAL 3 Lowered 4/30/99

BETA .55 (1.00 = Market)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
High:	12.6	14.8	14.9	18.9	20.4	26.4	23.4	24.9	25.8	38.4	38.1	38.8
Low:	9.6	11.5	12.8	12.9	15.4	18.8	18.0	18.3	20.5	22.0	27.9	28.6

Target Price Range 2002 | 2003 | 2004



2002-04 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+40%)	12%
Low	35	(+10%)	7%

Insider Decisions

	A	S	O	N	D	J	F	M	A
to Buy	0	0	0	4	1	4	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	2Q1998	3Q1998	4Q1998
to Buy	51	54	51
to Sell	42	38	39
Hld's(000)	7579	7635	7707

% TOT. RETURN 5/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	10.9	5.6
3 yr.	78.0	57.3
5 yr.	113.4	124.1

1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
25.93	27.04	28.15	24.91	23.04	19.92	20.25	18.84	16.64	17.83	21.14	21.65	17.52	23.18	25.69	24.90	*21.60*	*22.95*	Revenues per sh A	*27.85*
1.38	1.53	1.17	1.31	1.74	1.75	1.92	1.94	1.56	2.15	2.28	2.26	2.51	2.98	3.25	3.44	*3.35*	*3.75*	"Cash Flow" per sh	*4.35*
.91	1.04	.80	.77	1.10	1.19	1.21	1.22	.89	1.40	1.45	1.35	1.45	1.67	1.85	1.96	*1.90*	*2.20*	Earnings per sh B	*2.75*
.48	.54	.58	.60	.65	.72	.79	.83	.87	.91	.95	1.01	1.09	1.15	1.21	1.28	*1.36*	*1.42*	Div'ds Decl'd per sh C■	*1.60*
1.18	1.44	2.13	2.39	2.85	3.74	3.11	3.24	2.75	2.81	3.16	3.90	3.44	3.27	3.05	2.96	*4.15*	*3.15*	Cap'l Spending per sh	*3.10*
5.80	6.30	6.41	6.89	7.49	8.25	8.73	9.15	9.65	10.27	10.90	11.36	12.31	13.07	13.90	14.91	*15.40*	*16.30*	Book Value per sh D	*19.20*
13.36	13.96	14.37	17.40	17.87	20.33	20.78	21.43	24.73	25.80	26.15	26.58	28.84	29.55	30.19	30.74	*31.50*	*32.00*	Common Shs Outst'g E	*34.00*
5.7	6.3	13.2	12.1	10.2	9.1	10.3	11.3	16.3	12.3	15.4	15.7	13.8	13.9	13.8	16.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.48	.59	1.07	.82	.68	.76	.78	.84	1.04	.75	.91	1.03	.92	.87	.78	.86	*Value Line*		Relative P/E Ratio	*1.00*
9.4%	8.2%	7.4%	6.4%	5.8%	6.7%	6.3%	6.0%	6.0%	5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*
						420.8	403.8	411.6	459.9	552.8	575.4	505.2	685.1	775.5	765.3	*680*	*735*	Revenues ($mill) A	*950*
						24.9	25.7	20.6	35.3	37.5	35.5	40.3	48.6	55.2	60.3	*59.5*	*71.0*	Net Profit ($mill)	*93.0*
						33.7%	33.2%	32.2%	35.0%	38.4%	37.6%	38.7%	38.9%	39.1%	39.2%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
						5.9%	6.4%	5.0%	7.7%	6.8%	6.2%	8.0%	7.1%	7.1%	7.9%	*8.8%*	*9.7%*	Net Profit Margin	*9.8%*
						50.7%	47.0%	48.0%	46.6%	49.4%	50.9%	50.4%	50.3%	47.6%	44.7%	*45.0%*	*45.0%*	Long-Term Debt Ratio	*43.5%*
						49.3%	53.0%	52.0%	53.4%	50.6%	49.1%	49.6%	49.7%	52.4%	55.3%	*55.0%*	*55.0%*	Common Equity Ratio	*56.5%*
						367.7	369.8	459.3	496.2	563.0	615.0	716.0	777.1	800.8	829.3	*885*	*950*	Total Capital ($mill)	*1150*
						452.4	507.9	537.9	592.8	654.5	734.9	801.3	862.0	941.7	990.6	*1070*	*1130*	Net Plant ($mill)	*1270*
						9.5%	10.0%	6.8%	9.1%	8.6%	7.7%	7.5%	8.2%	8.9%	9.2%	*8.5%*	*9.0%*	Return on Total Cap'l	*9.5%*
						13.7%	13.1%	8.6%	13.3%	13.2%	11.8%	11.4%	12.6%	13.1%	13.2%	*12.5%*	*13.5%*	Return on Shr. Equity	*14.0%*
						13.7%	13.1%	8.6%	13.3%	13.2%	11.8%	11.4%	12.6%	13.1%	13.2%	*12.5%*	*13.5%*	Return on Com Equity	*14.0%*
						4.8%	4.2%	.2%	4.6%	4.4%	2.8%	2.7%	3.9%	4.6%	4.7%	*3.5%*	*5.0%*	Retained to Com Eq	*6.0%*
						65%	68%	98%	66%	67%	76%	76%	69%	65%	65%	*71%*	*64%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 1/31/99
Total Debt $445.0 mill. Due in 5 Yrs $189.0 mill.
LT Debt $371.0 mill. LT Interest $30.0 mill.
(Total interest coverage: 3.9x)

Pension Liability None

Pfd Stock None

Common Stock 30,924,595 shs.
as of 3/5/99

MARKET CAP: $1.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	1997	1998	1/31/99
Cash Assets	5.2	9.7	8.8
Other	127.0	132.8	222.8
Current Assets	132.2	142.5	231.6
Accts Payable	65.1	67.3	68.4
Debt Due	35.0	42.0	74.0
Other	55.4	76.6	100.4
Current Liab.	155.5	185.9	242.8
Fix. Chg. Cov.	339%	373%	390%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	1.0%	6.0%	*2.0%*
"Cash Flow"	7.5%	10.0%	*5.0%*
Earnings	6.0%	8.0%	*7.0%*
Dividends	6.5%	6.0%	*5.0%*
Book Value	6.5%	6.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan. 31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
1996	239.2	259.5	95.7	90.7	685.1
1997	312.5	259.3	104.0	99.7	775.5
1998	313.3	261.5	103.0	87.5	765.3
1999	255.7	239.2	*95.0*	*90.1*	*680*
2000	*275*	*255*	*105*	*100*	*735*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
1996	1.18	1.12	d.28	d.33	1.67
1997	1.26	1.06	d.19	d.28	1.85
1998	1.35	1.16	d.20	d.33	1.96
1999	1.31	1.11	*d.22*	*d.30*	*1.90*
2000	*1.40*	*1.28*	*d.20*	*d.28*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.26	.275	.275	.275	1.09
1996	.275	.29	.29	.29	1.15
1997	.29	.305	.305	.305	1.21
1998	.305	.325	.325	.325	1.28
1999	.325	.345			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 625,000 customers in North Carolina, South Carolina, and Tennessee. 1998 revenue mix: residential (42%), commercial (25%), industrial (21%), other (12%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 57.8% of revenues. '98 depreciation rate: 3.3%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,840 employees, 19,150 shareholders of record. Chairman, President & C.E.O.: John H. Maxheim. Incorporated in North Carolina. Address: P.O. Box 33068, Charlotte, North Carolina 28233. Telephone: 704-364-3120. Internet: www.piedmontng.com

The price of Piedmont Natural Gas stock has fallen more than 10% since our March review. The issue's diminished value largely stems from unfavorable operating trends exhibited in the April quarter just reported, as discussed below. Due to the ongoing lack of share earnings and price momentum, this issue's Timeliness rank has come down one step, to 5 (Lowest). However . . .

We believe that this equity will continue to provide relatively strong dividend growth. In the preceding quarter, the company increased its quarterly payment by approximately 6%. The current yield is pretty much in line with the gas distribution industry mean. Furthermore, this stock has a Safety rank of 2 (Above Average), making it a worthwhile holding for conservative, income-oriented investors.

We have lowered our fiscal-1999 share-earnings estimate by $0.15, to $1.90. (Year ends October 31st.) This adjustment is mainly attributable to April-period share net that fell short of our expectations set in the March review. Significantly warmer-than-normal temperatures during the period resulted in reduced gas sales. Results for April were hit especially hard since that month falls outside of the scope of the utility's weather-normalization adjustment rate mechanism. Indeed, April's temperatures were approximately 25% warmer than normal. The nonregulated propane business, meantime, has suffered from the lack of any weather-adjustment provisions whatsoever. Finally, it now appears that near-term demand has been much greater than anticipated for the Southstar Energy Services LLC marketing venture, which is apt to result in considerably higher start-up expenses. Nevertheless . . .

We expect a share-net recovery in fiscal 2000. Healthy economic conditions in the utility service territories will likely allow Piedmont to post customer growth at a 4% to 5% annual clip, which would be two to three times the industry average. Too, the company seems to have a good handle on its operating and maintenance costs. Note that our estimates are based on the assumption that normal weather will prevail going forward.

Oscar L. Vidal *June 25, 1999*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '85, 11¢. Excl. nonrecurring charge: '97, 4¢. Next egs. report due early Sep.
(C) Next div'd mtg late Aug. Goes ex late Sep. Approx. dividend payment dates: 15th of Jan., April, July, Oct.
■ Div'd reinvest. plan available; 5% discount.
(D) Incl. def'd chrgs. In '98: $2.5 mill., 8¢/sh.
(E) In mill., adj. for stk. splits.
(F) Qtrs. may not add to total due to change in shs. outstanding.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	85

PIEDMONT NAT'L. NYSE-PNY

RECENT PRICE 35 | P/E RATIO 17.4 (Trailing: 18.0; Median: 14.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.9% | VALUE LINE 483

TIMELINESS 4 Lowered 9/4/98
SAFETY 2 New 7/27/90
TECHNICAL 3 Lowered 1/22/99
BETA .80 (1.00 = Market)

													Target Price Range
High:	12.6	14.8	14.9	16.9	20.4	26.4	23.4	24.9	25.8	36.4	36.1	36.6	2002 / 2003 / 2004
Low:	9.6	11.5	12.8	12.9	15.4	18.8	18.0	18.3	20.5	22.0	27.9	28.6	

2002-04 PROJECTIONS

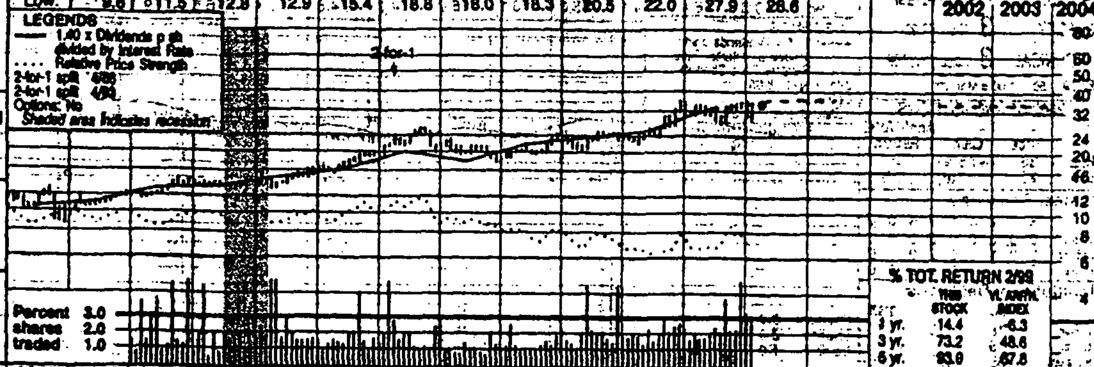
	Price	Gain	Ann'l Total Return
High	50	(+45%)	12%
Low	35	(Nil)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	1	4	0	0	0	1	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	1	0	0	0	0	0	0	0

Institutional Decisions

	2Q1998	3Q1998	4Q1998
to Buy	51	54	51
to Sell	42	38	39
Hld's(000)	7579	7635	7707



% TOT. RETURN 2/99

	THIS STOCK	VL ARITH. INDEX
1 yr.	14.4	-6.3
3 yr.	73.2	48.6
5 yr.	93.0	67.8

1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	© VALUE LINE PUB., INC.	02-04
25.93	27.04	28.15	24.01	23.04	19.62	20.25	18.84	18.64	17.83	21.14	21.65	17.52	23.18	25.69	24.90	*23.35*	*24.40*	Revenues per sh A	*27.95*
1.38	1.53	1.17	1.31	1.74	1.75	1.92	1.94	1.56	2.15	2.28	2.26	2.51	2.98	3.25	3.44	*3.50*	*3.75*	"Cash Flow" per sh	*4.35*
.91	1.04	.80	.77	1.10	1.19	1.21	1.22	.89	1.40	1.45	1.35	1.45	1.67	1.85	1.96	*2.05*	*2.20*	Earnings per sh B	*2.75*
.48	.54	.58	.60	.65	.72	.79	.83	.87	.91	.95	1.01	1.09	1.15	1.21	1.28	*1.36*	*1.42*	Div'ds Decl'd per sh C■	*1.60*
1.18	1.44	2.13	2.39	2.85	3.74	3.11	3.24	2.75	2.81	3.16	3.90	3.44	3.27	3.05	2.98	*4.15*	*3.15*	Cap'l Spending per sh	*3.10*
5.80	6.30	6.41	6.99	7.49	8.25	8.73	9.15	9.65	10.27	10.90	11.36	12.31	13.07	13.90	14.91	*15.55*	*16.40*	Book Value per sh D	*19.30*
13.36	13.86	14.37	17.40	17.87	20.33	20.78	21.43	24.73	25.80	26.15	26.58	28.84	29.55	30.19	30.74	*31.50*	*32.00*	Common Shs Outst'g E	*34.00*
5.7	6.3	13.2	12.1	10.2	8.1	10.3	11.3	16.3	12.3	15.4	15.7	13.8	13.9	13.6	16.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.5*
.48	.59	1.07	.82	.68	.76	.78	.84	1.04	.75	.91	1.03	.92	.87	.78	.86			Relative P/E Ratio	*1.05*
8.4%	8.2%	7.4%	6.4%	5.8%	6.7%	6.3%	6.0%	6.0%	5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%			Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 1/31/99
Total Debt $445.0 mill. Due in 5 Yrs $189.0 mill.
LT Debt $371.0 mill. LT Interest $30.0 mill.
(Total interest coverage: 3.9x)

Pension Liability None

Pfd Stock None

Common Stock 30,924,585 shs. as of 3/5/99

MARKET CAP: $1.1 billion (Mid Cap)

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		02-04
420.8	403.8	411.6	459.9	552.8	575.4	505.2	685.1	775.5	765.3	*735*	*780*	Revenues ($mill) A	*950*
24.9	25.7	20.6	35.3	37.5	35.5	40.3	48.6	55.2	60.3	*64.5*	*71.0*	Net Profit ($mill)	*93.0*
33.7%	33.2%	32.2%	35.0%	36.4%	37.6%	38.7%	38.9%	39.1%	39.2%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
5.9%	6.4%	5.0%	7.7%	6.8%	6.2%	8.0%	7.1%	7.1%	7.9%	*8.8%*	*9.1%*	Net Profit Margin	*9.8%*
50.7%	47.0%	48.0%	46.6%	49.4%	50.9%	50.4%	50.3%	47.6%	44.7%	*45.0%*	*44.5%*	Long-Term Debt Ratio	*43.0%*
49.3%	53.0%	52.0%	53.4%	50.6%	49.1%	49.6%	49.7%	52.4%	55.3%	*55.0%*	*55.5%*	Common Equity Ratio	*57.0%*
367.7	369.8	459.3	496.2	563.0	615.0	716.0	777.1	800.8	829.3	*890*	*950*	Total Capital ($mill)	*1160*
452.4	507.9	537.9	592.8	654.5	734.9	801.3	862.0	941.7	990.6	*1070*	*1130*	Net Plant ($mill)	*1270*
9.5%	10.0%	6.8%	9.1%	8.6%	7.7%	7.5%	8.2%	8.9%	9.2%	*9.0%*	*9.0%*	Return on Total Cap'l	*9.5%*
13.7%	13.1%	8.6%	13.3%	13.2%	11.8%	11.4%	12.6%	13.1%	13.2%	*13.0%*	*13.5%*	Return on Shr. Equity	*14.0%*
13.7%	13.1%	8.6%	13.3%	13.2%	11.8%	11.4%	12.6%	13.1%	13.2%	*13.0%*	*13.5%*	Return on Com Equity	*14.0%*
4.8%	4.2%	2%	4.6%	4.4%	2.8%	2.7%	3.9%	4.6%	4.7%	*4.5%*	*5.0%*	Retained to Com Eq	*8.0%*
65%	68%	98%	66%	67%	76%	76%	69%	65%	65%	*66%*	*64%*	All Div'ds to Net Prof	*58%*

CURRENT POSITION ($MILL.)	1997	1998	1/31/99
Cash Assets	5.2	9.7	8.8
Other	127.0	132.8	222.8
Current Assets	132.2	142.5	231.6
Accts Payable	65.1	67.3	68.4
Debt Due	35.0	42.0	74.0
Other	55.4	76.6	100.4
Current Liab.	155.5	185.9	242.8
Fix. Chg. Cov.	339%	373%	390%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '96-'98 to '02-'04
Revenues	1.0%	6.0%	*2.0%*
"Cash Flow"	7.5%	10.0%	*5.0%*
Earnings	6.0%	8.0%	*7.0%*
Dividends	6.5%	6.0%	*5.0%*
Book Value	6.5%	6.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan. 31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
1996	239.2	259.5	95.7	90.7	685.1
1997	312.5	259.3	104.0	99.7	775.5
1998	313.3	261.5	103.0	87.5	765.3
1999	255.7	*270*	*110*	*99.3*	*735*
2000	*280*	*280*	*115*	*105*	*780*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
1996	1.18	1.12	d.28	d.33	1.67
1997	1.26	1.08	d.19	d.28	1.85
1998	1.35	1.16	d.20	d.33	1.96
1999	1.31	*1.23*	*d.20*	*d.29*	*2.05*
2000	*1.40*	*1.28*	*d.20*	*d.28*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
1995	.26	.275	.275	.275	1.09
1996	.275	.29	.29	.29	1.15
1997	.29	.305	.305	.305	1.21
1998	.305	.325	.325	.325	1.28
1999	.325	.345			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 625,000 customers in North Carolina, South Carolina, and Tennessee. 1998 revenue mix: residential (42%), commercial (25%), industrial (21%), other (12%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 57.8% of revenues. '98 depreciation rate: 3.3%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,840 employees, 19,150 shareholders of record. Chairman, President & C.E.O.: John H. Maxheim. Incorporated in North Carolina. Address: P.O. Box 33068, Charlotte, North Carolina 28233. Telephone: 704-364-3120. Internet: www.piedmontng.com

Piedmont Natural Gas Company should post further share-earnings advances in fiscal 1999 and 2000. (Years end October 31st.) Our estimates are based on an assumption of normal climate going forward. Natural gas volumes were hampered somewhat in the January quarter, when temperatures were 19% warmer than normal and 17% warmer than the year-ago period. Some protection has been afforded, though, by a weather normalization adjustment rate mechanism currently in place. Moreover, healthy economic trends in the utility markets served will likely help the company post annual customer growth in the 4% to 5% range, which amounts to about two to three times the national average. Finally, the gas distributor appears to have a good handle on its operating and maintenance expenses.

A potential regulatory filing in Tennessee may well provide a boost to revenues. We will have more details in the next month or two when management has completed its evaluation of this service territory. Meanwhile, there will likely be no activity on the regulatory front in the Carolinas.

The share-net contribution from Piedmont's nonregulated businesses is apt to be modest. These efforts consist mainly of propane gas sales and energy marketing. Propane operations have been hampered by unfavorable weather conditions over the past few months. The energy marketing side, meantime, is still in its infancy, and will probably face more startup losses in coming quarters. Piedmont, along with AGL Resources Inc. and Dynegy Inc., is part of an energy venture focused on the Southeast U.S. called Southstar Energy Services LLC. Southstar has made considerable progress in building upon its market share.

Relatively rapid dividend growth continues to be this equity's primary appeal. The company recently increased its quarterly payment by about 6%. Nonetheless, the yield falls short of the gas distribution industry mean. This stock, however, holds a Safety rank of 2 (Above Average), which potentially makes it a suitable holding for conservative, income-oriented accounts.

Oscar L. Vidal *March 26, 1999*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '85, 11¢. Excl. nonrecurring charge: '97, 4¢. Next egs. report due about Jun. 4.
(C) Next div'd mtg late May. Goes ex late Jun. Approx. dividend payment dates: 15th of Jan., April, July, Oct.
■ Div'd reinvest. plan available; 5% discount.
(D) Incl. def'd chrgs. In '98: $2.5 mill., 8¢/sh.
(E) In mill., adj. for stk. splits.
(F) Qtrs. may not add to total due to change in shs. outstanding.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	85

STANDARD
&POOR'S
STOCK REPORTS

Atmos Energy

NYSE Symbol **ATO**
In S&P SmallCap 600

08-MAY-99 Industry: Natural Gas

Summary: This company distributes natural gas and propane to more than one million customers in 13 states.

Quantitative Evaluations

Outlook (1 Lowest—5 Highest)
• 3–

Fair Value
• 27¾

Risk
• Low

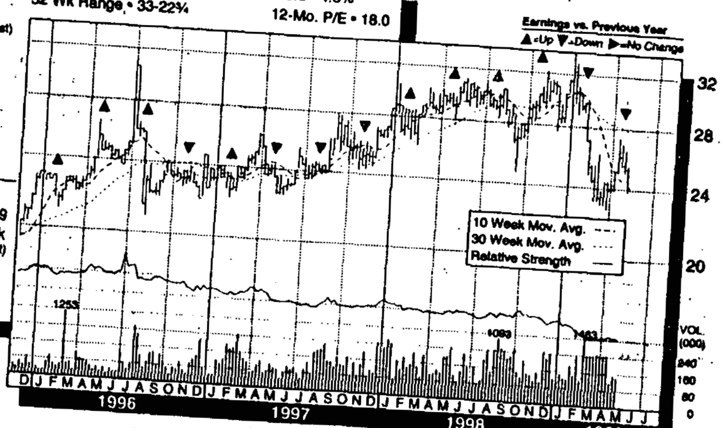
Earn./Div. Rank
• B+

Technical Eval.
• Bearish since 2/99

Rel. Strength Rank (1 Lowest—99 Highest)
• 22

Insider Activity
• NA

Recent Price • 24⅝
52 Wk Range • 33-22¾
Yield • 4.6%
12-Mo. P/E • 18.0



Business Profile - 10-FEB-99

This natural gas distributor expects to achieve $375 million of long-term cost savings following the successful integration of United Cities Gas Co., which was acquired in 1997. In connection with the integration, ATO has cut 635 positions, and plans to reduce the headcount by an additional 240. The company believes its geographic expansion hedges its exposure to weather patterns, economic conditions, and regulatory climates. In November 1998, the dividend was increased, marking the 11th consecutive annual dividend increase. In July 1998, in ATO's first public debt program, the company sold $150 million of 30-year, 6.75% bonds. Proceeds were used to retire short-term debt.

Operational Review - 10-FEB-99

Gross profit (revenues less purchased gas costs) in the three months ended December 31, 1998, fell 8.4%, year to year, reflecting lower gas throughput, as a result of weather that was 15% warmer than normal. After a significant increase in depreciation and amortization charges, despite a slightly lower tax rate, net income fell 24%, to $15.4 million ($0.50 a share, diluted, on 2.6% more shares), from $20.1 million ($0.68).

Stock Performance - 07-MAY-99

In the past 30 trading days, ATO's shares have increased 0.79%, compared to a 5% rise in the S&P 500. Average trading volume for the past five days was 28,020 shares, compared with the 40-day moving average of 47,636 shares.

Key Stock Statistics

Dividend Rate/Share	1.10	Shareholders	29,667
Shs. outstg. (M)	30.7	Market cap. (B)	$0.740
Avg. daily vol. (M)	0.034	Inst. holdings	34%
Tang. Bk. Value/Share	12.21		
Beta	0.18		

Value of $10,000 invested 5 years ago: $ 16,122

Fiscal Year Ending Sep. 30

	1999	1998	1997	1996	1995	1994
Revenues (Million $)						
1Q	210.2	295.3	280.6	130.5	117.8	145.5
2Q	261.4	288.6	362.6	191.1	157.3	186.9
3Q	—	137.3	143.7	93.57	84.69	90.01
4Q	—	127.0	119.9	68.60	75.99	77.35
Yr.	—	848.2	906.8	483.7	435.8	499.8
Earnings Per Share ($)						
1Q	0.50	0.68	0.62	0.59	0.42	0.47
2Q	0.94	1.26	1.04	1.15	0.91	0.87
3Q	—	0.06	-0.10	0.02	0.01	-0.08
4Q	—	-0.13	-0.74	-0.25	-0.11	-0.29
Yr.	—	1.84	0.81	1.42	1.06	1.06

Next earnings report expected: late July

Dividend Data (Dividends have been paid since 1984.)

Amount ($)	Date Decl.	Ex-Div. Date	Stock of Record	Payment Date
0.265	May. 13	May. 21	May. 26	Jun. 10 '98
0.265	Aug. 12	Aug. 21	Aug. 25	Sep. 10 '98
0.275	Nov. 11	Nov. 23	Nov. 25	Dec. 10 '98
0.275	Feb. 10	Feb. 23	Feb. 25	Mar. 10 '99

STANDARD
&POOR'S
STOCK REPORTS

Atmos Energy Corporation

08-MAY-99

Business Summary - 10-FEB-99

Atmos Energy Corp. distributes and sells natural gas and propane to approximately 1,058,000 residential, commercial, industrial, agricultural, and other customers. It sells natural gas through about 1,020,000 meters, in 802 cities, towns and communities located in Texas, Louisiana, Kentucky, Colorado, Kansas, Illinois, Tennessee, Iowa, Virginia, Georgia, South Carolina, and Missouri. ATO also transports gas for others through parts of its distribution system. The company's utility divisions are Energas Co., Greeley Gas Co., Trans Louisiana Gas Co., United Cities Gas Co. (UCG), and Western Kentucky Gas Co.

The natural gas industry is subject to a number of factors, including a continuing need to obtain adequate and timely rate relief from regulatory authorities; inherent seasonality of the business; competition with alternate fuels; competition with other gas sources for industrial customers; and possible volatility in the supply and price of natural gas. About 88% of revenues in FY 98 (Sep.) came from sales at rates set by or subject to approval by local or state authorities.

ATO also operates certain non-utility businesses through wholly owned subsidiaries. UCG Storage Co. provides natural gas storage services, and owns natural gas storage fields in Kentucky and Kansas. UCG Energy Corp. leases appliances, real estate and equipment, and vehicles, owns a small interest in a partnership engaged in exploration and production, and has a 45% interest in a gas marketing business. Atmos Propane Inc., a subsidiary of UCG Energy, is engaged in the retail distribution and wholesale supply of propane. At September 30, 1998, Atmos Propane served 37,400 customers.

During FY 98, ATO sold 138,550 MMcf of gas, at an average price of $4.87 per Mcf and an average cost of $3.24 per Mcf. This compared with 147,244 MMcf sold in FY 97, at an average price and cost of $5.11 per Mcf $3.51 per Mcf, respectively. The company transported 56,224 MMcf and 48,000 MMcf in 1998 and 1997, respectively; the average transportation revenue per Mcf was $0.43 and $0.41. Storage and energy services volumes totaled 20,823 MMcf and 16,964 MMcf. Propane sales in FY 98 and FY 97 totaled 33.7 million gallons and 33.0 million gallons, respectively. Heating degree days (the equivalent to each degree that the average of the high and low temperatures for a day is below 65 degrees; the greater the number of heating days, the colder the climate) totaled 3,799 in FY 98, equal to 95% of normal, versus 3,909 days, or 98% of normal, in FY 97.

Per Share Data ($) (Year Ended Sep. 30)	1998	1997	1996	1995	1994	1993	1992	1991	1990	1989
Tangible Bk. Val.	12.21	11.04	10.75	10.20	9.78	10.39	9.17	8.88	8.71	8.51
Earnings	1.84	0.81	1.51	1.22	0.97	1.45	0.97	0.80	0.98	0.89
Dividends	1.06	1.01	0.96	0.92	0.88	0.85	0.83	0.80	0.77	0.75
Payout Ratio	58%	125%	64%	75%	91%	59%	85%	100%	79%	84%
Prices - High	32¼	27⅞	31	23	20¼	21⅛	15⅞	15⅜	12½	12
- Low	24¾	22⅛	20⅞	18⅛	15⅞	15⅛	12¾	10⅞	10⅜	9¾
P/E Ratio - High	18	34	21	19	21	15	16	19	13	14
- Low	13	27	14	13	16	10	13	13	11	11
Income Statement Analysis (Million $)										
Revs.	848	907	484	436	500	388	340	336	352	342
Depr.	47.6	45.3	20.8	20.7	18.8	13.6	13.6	12.6	13.5	12.7
Maint.	10.3	12.0	4.2	4.3	5.9	3.8	3.3	3.9	4.3	5.8
Fxd. Chgs. Cov.	3.5	2.1	3.5	3.1	2.9	3.5	2.4	2.1	2.2	2.2
Constr. Credits	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Eff. Tax Rate	37%	37%	36%	34%	36%	37%	33%	28%	32%	31%
Net Inc.	55.3	23.8	23.9	18.9	14.7	15.7	10.0	7.9	9.0	8.1
Balance Sheet & Other Fin. Data (Million $)										
Gross Prop.	1,446	1,333	666	595	544	399	364	333	307	300
Cap. Exp.	135	122	77.6	62.9	50.4	38.4	33.3	30.2	25.3	21.6
Net Prop.	918	849	414	363	327	241	219	208	195	195
Capitalization:										
LT Debt	399	303	122	131	138	86.3	91.3	96.6	81.8	91.9
% LT Debt	52	48	42	45	48	42	49	51	51	54
Pfd.	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
% Pfd.	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Common	371	327	172	158	150	118	96.0	90.9	79.8	77.7
% Common	48	52	59	55	52	58	51	49	49	46
Total Cap.	850	718	334	323	318	232	214	212	169	195
% Oper. Ratio	89.2	94.2	91.9	92.5	94.7	93.3	94.0	94.8	94.5	94.9
% Earn. on Net Prop.	9.2	6.3	10.0	9.3	8.4	11.3	9.6	9.0	9.9	9.1
% Return On Revs.	6.5	2.6	5.0	4.3	2.9	4.0	2.9	2.4	2.5	2.4
% Return On Invest. Capital	7.1	6.2	11.8	10.1	9.1	11.6	9.7	9.0	10.4	9.6
% Return On Com. Equity	15.8	9.5	14.5	12.2	10.2	14.7	10.8	9.3	11.4	10.5

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs. Bold denotes diluted EPS (FASB 128)-prior periods restated. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked.

Office—Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, TX 75240. Tel—(972) 934-9227. Website—http://www.atmosenergy.com Chrmn, Pres & CEO—R. W. Best. EVP & CFO—L. J. Dagley. Secy—G. A. Blanscet. VP & Investor Contact—Lynn Hord (972-855-3729). Dirs—T. W. Bain II, R. W. Best, D. Busbee, R.W. Cardin, T. J. Garland, G. C. Koonce, V. J. Lewis, T. C. Meredith, P. E. Nichol, C. S. Quinn, L. Schlessman, C. K. Vaughan, R. Ware II. Transfer Agent & Registrar—Boston EquiServe, L.P. Organized—in Texas in 1983. Empl— 2,193. S&P Analyst: Ephraim Juskowicz

Energen Corp.

NYSE Symbol **EGN**
In S&P SmallCap 600

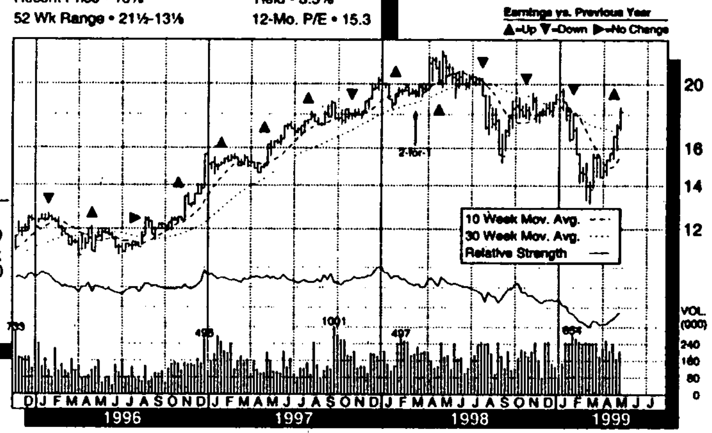
08-MAY-99 **Industry:** Natural Gas

Summary: This diversified energy company's business activities include natural gas distribution, and oil and gas exploration and production.

Quantitative Evaluations
Outlook (1 Lowest—5 Highest)
• 2
Fair Value
• 17¾
Risk
• Low
Earn./Div. Rank
• A

Technical Eval.
• Bearish since 2/99
Rel. Strength Rank (1 Lowest—99 Highest)
• 79
Insider Activity
• NA

Recent Price • 18⅛ Yield • 3.5%
52 Wk Range • 21½-13⅛ 12-Mo. P/E • 15.3



Business Profile - 04-MAR-99

In January 1999, the company stated that, with oil prices at or near 12-year lows, EGN was focusing on natural gas production and that over 85% of this output was hedged at an average price of $2.31 per Mcf. In October 1998, Energen Resources acquired TOTAL Minatome Corp. and then sold 31% of TOTAL Minatome to Westport Oil and Gas Company, Inc. The TOTAL Minatome purchase raised the company's proved oil and natural gas reserves to nearly one trillion cubic feet equivalent. Energen Resources estimates that it will spend $70 million during the next several years to exploit proved, undeveloped reserves.

Operational Review - 04-MAR-99

For the three months ended December 31,1998, operating revenues declined 9.5%, year to year, due mainly to a 25% decrease in demand for natural gas distribution related to warmer weather, and a decline in charges recovered through the Gas Supply Adjustment (GSA), partially offset by significantly higher oil and gas revenues associated with acquisitions. Expenses were down 10%, as a 25% increase in operations and maintenance expense and 30% higher depreciation and depletion were outweighed by a 47% drop in the cost of gas. Following 36% greater interest expense, pretax income fell 47%. After a tax benefit of $278,000, versus taxes at 8.9%, net income declined 37% to $3,842,000 ($0.13 a share), from $6,127,000 ($0.21).

Stock Performance - 07-MAY-99

In the past 30 trading days, EGN's shares have increased 26%, compared to a 5% rise in the S&P 500. Average trading volume for the past five days was 40,860 shares, compared with the 40-day moving average of 49,921 shares.

Key Stock Statistics

Dividend Rate/Share	0.64	Shareholders	9,140
Shs. outstg. (M)	29.6	Market cap. (B)	$0.538
Avg. daily vol. (M)	0.042	Inst. holdings	48%
Tang. Bk. Value/Share	11.99		
Beta	0.69		

Value of $10,000 invested 5 years ago: $ 20,927

Fiscal Year Ending Sep. 30

	1999	1998	1997	1996	1995	1994
Revenues (Million $)						
1Q	114.0	125.9	97.00	78.82	73.48	87.92
2Q	188.4	198.0	182.9	171.0	140.8	188.1
3Q	—	93.91	90.88	87.13	61.53	73.13
4Q	—	78.05	77.41	62.50	45.37	47.94
Yr.	—	502.6	448.2	399.4	321.2	377.1
Earnings Per Share ($)						
1Q	0.13	0.21	0.14	0.10	0.13	0.11
2Q	1.42	1.37	1.21	1.06	0.99	1.01
3Q	—	Nil	0.12	0.05	0.05	0.18
4Q	—	-0.34	-0.29	-0.23	-0.29	-0.21
Yr.	—	1.23	1.14	0.97	0.89	1.09

Next earnings report expected: late July

Dividend Data (Dividends have been paid since 1943.)

Amount ($)	Date Decl.	Ex-Div. Date	Stock of Record	Payment Date
0.160	Jul. 22	Aug. 12	Aug. 14	Sep. 01 '98
0.160	Oct. 28	Nov. 10	Nov. 13	Dec. 01 '98
0.160	Jan. 27	Feb. 10	Feb. 12	Mar. 01 '99
0.160	Apr. 28	May. 12	May. 14	Jun. 01 '99

Business Summary - 04-MAR-99

Energen (EGN) is a diversified energy holding company engaged in natural gas distribution and oil and natural gas exploration and production; its two major subsidiaries are Alabama Gas Corp. (Alagasco) and Energen Resource Corp., (formerly Taurus Exploration Inc.). While Alagasco earns within its allowed range of return of equity, the company's five-year plan, spanning through FY 00 (Sep.), calls for Energen to invest, through Energen Resources, $400 million in the acquisition of producing properties with development potential, and $100 million in offshore Gulf of Mexico exploration and development.

Alagasco, Alabama's largest gas distribution utility, purchases gas through interstate and intrastate marketers and suppliers and distributes the purchased gas through its distribution facilities for sale to end-users of natural gas. Alagasco also provides transportation services to industrial and commercial customers located on its distribution system. These customers purchase gas directly from producers, marketers or suppliers and arrange for delivery of the gas into the Alagasco distribution system; Alagasco charges a fee to transport the gas through its distribution system to the customer's facility. In FY 98, Alagasco served an average of 423,602 residential customers, 34,733 small commercial and industrial customers, and 49 large commercial and industrial transportation customers. Deliveries of sales and transportation gas totaled 115,347 million cubic feet (MMcf) in FY 1998.

The Alagasco distribution system includes approximately 9,060 miles of main and more than 9,800 miles of service lines, odorization and regulation facilities, and customer meters. Alagasco also operates two liquefied natural gas facilities, which it uses to meet peak demand. Alagasco's distribution system is connected to and has firm transportation contracts with two major interstate pipeline systems: Southern and Transcontinental Gas Pipe Line Corp.

Energen Resources is involved in the exploration and production of natural gas and oil in the Gulf of Mexico, and through coalbed methane projects in Alabama's Black Warrior Coal Basin. At the end of FY 98, Energen Resources' remaining recoverable reserves totaled 764.9 billion cubic feet equivalent (Bcfe), and were located primarily in Alabama, New Mexico, Texas, Mississippi, Louisiana and the Gulf of Mexico. Natural gas represents over 70% of Energen Resources' reserves with oil and natural gas liquids constituting the balance. In October 1998, Energen Resources acquired TOTAL Minatome Corp. and then sold 31% of TOTAL Minatome to Westport Oil and Gas Company, Inc. Energen paid about $135 million for TOTAL Minatome, raising EGN's proved oil and natural gas reserves to nearly one trillion cubic feet equivalent.

Per Share Data ($) (Year Ended Sep. 30)	1998	1997	1996	1995	1994	1993	1992	1991	1990	1989
Tangible Bk. Val.	23.98	10.46	8.44	7.97	7.65	6.80	6.38	6.04	6.11	5.84
Earnings	1.23	1.16	0.97	0.89	1.09	0.89	0.77	0.71	0.68	0.59
Dividends	0.94	0.60	0.58	0.56	0.55	0.53	0.51	0.48	0.45	0.43
Payout Ratio	76%	52%	60%	64%	50%	59%	66%	67%	66%	72%
Prices - High	22½	20⅝	15⅝	12⅝	12	13⅛	9⅝	9½	10¼	12¼
- Low	15⅛	14½	10⅞	10⅛	9⅝	9⅛	7½	8	8	7¾
P/E Ratio - High	18	18	16	14	11	15	13	13	15	20
- Low	12	13	11	11	9	10	10	11	12	13
Income Statement Analysis (Million $)										
Revs.	503	448	399	321	377	357	332	326	325	309
Depr.	81.0	59.7	41.1	29.6	28.0	25.3	26.3	24.1	23.0	22.4
Maint.	NA	11.1	11.1	9.8	9.5	9.2	9.1	8.2	8.4	6.8
Fxd. Chgs. Cov.	2.1	2.4	2.9	3.0	3.5	3.0	2.5	2.5	2.5	2.6
Constr. Credits	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Eff. Tax Rate	NA	9.65%	19%	16%	22%	16%	2.40%	2.50%	8.90%	8.60%
Net Inc.	36.2	29.0	21.5	19.3	23.8	18.1	15.7	14.1	13.2	11.1
Balance Sheet & Other Fin. Data (Million $)										
Gross Prop.	1,152	1,042	545	504	465	429	411	393	377	357
Cap. Exp.	175	283	168	68.9	45.5	43.7	22.5	46.9	41.9	59.5
Net Prop.	756	667	277	256	233	213	208	206	205	203
Capitalization:										
LT Debt	373	280	196	132	118	85.9	90.6	77.7	82.8	86.2
% LT Debt	53	48	51	43	42	38	41	39	40	43
Pfd.	Nil	Nil	Nil	Nil	Nil	Nil	1.8	1.8	1.8	2.5
% Pfd.	Nil	Nil	Nil	Nil	Nil	Nil	0.80	0.90	0.90	1.20
Common	329	301	188	174	167	140	130	122	121	113
% Common	47	52	49	57	59	62	58	61	59	56
Total Cap.	702	581	385	312	292	232	230	225	236	236
% Oper. Ratio	87.3	89.1	91.6	90.0	92.2	92.5	93.2	92.9	93.0	94.1
% Earn. on Net Prop.	8.6	9.4	12.7	13.2	13.1	12.7	10.8	11.2	11.9	9.6
% Return On Revs.	7.2	6.5	5.4	6.0	6.3	5.1	4.7	4.3	4.1	3.6
% Return On Invest. Capital	5.6	6.1	10.2	11.5	13.4	12.5	11.5	10.7	10.3	8.9
% Return On Com. Equity	11.5	11.8	11.9	11.3	15.5	13.4	12.5	12.0	11.3	11.0

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs. Bold denotes diluted EPS (FASB 128)-prior periods restated. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked.

Office—605 21st Street North, Birmingham, AL 35203. Tel—(205) 326-2700. Website—http://www.energen.com Chrmn, Pres & CEO—W. M. Warren Jr. EVP-Fin, Treas & CFO—G. C. Ketcham. Secy—D. C. Reynolds. Investor Contact—Julie S. Ryland (205-326-2634). Dirs—S. D. Ban, J. W. Banton, R. D. Cash, J. M. Davis Jr., J. S. M. French, R. J. Lysinger, W. M. Warren Jr. Transfer Agent & Registrar—First Chicago Trust Company of New York. Incorporated—in Alabama in 1929. Empl— 1,421. S&P Analyst: John D. Staszak

STANDARD
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STOCK REPORTS

Laclede Gas

NYSE Symbol **LG**

08-MAY-99

Industry: Natural Gas

Summary: This company primarily distributes natural gas on a retail basis in St. Louis and nearby suburban areas.

Quantitative Evaluations

Outlook (1 Lowest—5 Highest)
• 1

Fair Value
• 19⅝

Risk
• Low

Earn./Div. Rank
• B

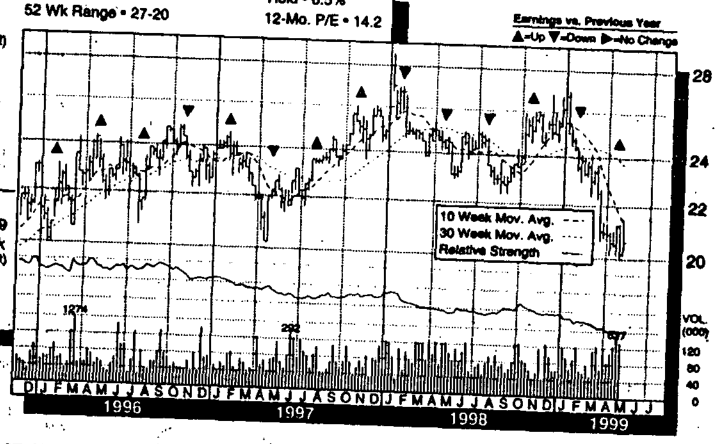
Technical Eval.
• Bearish since 2/99

Rel. Strength Rank (1 Lowest—99 Highest)
• 23

Insider Activity
• NA

Recent Price • 20⅝
52 Wk Range • 27-20

Yield • 6.5%
12-Mo. P/E • 14.2



Business Profile - 07-JAN-99

The company's gas supply incentive plan, which became effective October 1, 1996, for a three-year period, as part of a settlement reached in LG's last rate case, continues to provide significant benefits for both shareowners and customers. Under the plan, the company and its customers share in certain gains and losses as measured against benchmark levels of gas costs as related to the acquisition, utilization and management of LG's gas supply assets. As part of the plan, the company sells gas supply and pipeline capacity in markets outside its normal service territory. The program contributed $6.4 million to pretax income in FY 98 (Sep.). In October 1998, a settlement was reached on a rate increase proposal filed by the company in February.

Operational Review - 07-JAN-99

Revenues fell 9.2% in FY 98 (Sep.), primarily reflecting warmer weather conditions that resulted in reduced customer consumption. Total utility operating expenses declined 9.5%, aided by lower gas and propane expenses reflecting the lower volume, a lower provision for uncollectible accounts and reduced pension costs. Following 11% greater interest expense, net income was down 14%, to $27,892,000 ($1.58 a share, after preferred dividends), from $32,466,000 ($1.84).

Stock Performance - 07-MAY-99

In the past 30 trading days, LG's shares have declined 1%, compared to a 5% rise in the S&P 500. Average trading volume for the past five days was 68,500 shares, compared with the 40-day moving average of 43,059 shares.

Key Stock Statistics

Dividend Rate/Share	1.34	Shareholders	10,600
Shs. outstg. (M)	18.7	Market cap. (B)	$0.386
Avg. daily vol. (M)	0.062	Inst. holdings	32%
Tang. Bk. Value/Share	14.52		
Beta	0.34		

Value of $10,000 invested 5 years ago: $ 11,636

Fiscal Year Ending Sep. 30

	1999	1998	1997	1996	1995	1994
Revenues (Million $)						
1Q	149.7	199.7	193.9	155.0	122.2	167.3
2Q	207.0	213.8	264.0	246.6	191.6	233.0
3Q	—	77.19	84.19	86.00	67.60	74.64
4Q	—	56.54	60.75	57.22	50.49	48.94
Yr.	—	547.2	602.8	545.8	431.9	523.9
Earnings Per Share ($)						
1Q	0.55	0.78	0.92	0.90	0.56	0.77
2Q	1.14	1.04	1.22	1.37	1.15	1.19
3Q	—	-0.06	0.04	-0.02	-0.12	-0.18
4Q	—	-0.18	-0.34	-0.37	-0.25	-0.36
Yr.	—	1.58	1.84	1.87	1.27	1.42

Next earnings report expected: early June

Dividend Data (Dividends have been paid since 1946.)

Amount ($)	Date Decl.	Ex-Div. Date	Stock of Record	Payment Date
0.330	May. 28	Jun. 09	Jun. 11	Jul. 01 '98
0.330	Aug. 27	Sep. 09	Sep. 11	Oct. 01 '98
0.335	Nov. 19	Dec. 09	Dec. 11	Jan. 04 '99
0.335	Feb. 25	Mar. 09	Mar. 11	Apr. 01 '99

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STANDARD
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STOCK REPORTS

Laclede Gas Company

08-MAY-99

Business Summary - 07-JAN-99

Laclede Gas Co. is a public utility engaged primarily in the retail distribution and transportation of natural gas, serving the City of St. Louis, St. Louis County, the City of St. Charles and parts of eight other towns and counties in Missouri. Revenue breakdown by class of customer in recent fiscal years (ended September):

	1998	1997	1996
Residential	67%	66%	68%
Commercial & interruptible	24%	25%	26%
Other	9%	9%	6%

As an adjunct to its gas distribution and transportation business, LG operates underground natural gas storage fields and is engaged in the transportation and storage of liquid propane. Laclede has engaged in exploration for and development of natural gas on a utility and a nonutility basis.

During FY 98, Laclede purchased natural gas from a diverse group of 37 suppliers. Due to an unseasonably warm fiscal year, natural gas purchased by Laclede for delivery to its service area through the Mississippi River Transmission system totaled 78.0 Bcf, versus 85.3 Bcf in FY 97. LG purchased another 10.0 Bcf of gas in FY 98 through Panhandle Eastern Pipeline Co. and Missouri Pipeline Co. for delivery to Laclede take-points in St. Charles and Franklin Counties.

Recently, LG acquired direct access to the Mid-Continent producing region as a result of an expansion of the Williams Gas Pipeline. Laclede said the extension of the pipeline into the western portion of its service area provides it with competitively-priced supplemental gas supplies with which to serve this fast-growing segment of its customer base.

Flowing pipeline gas is supplemented with natural gas withdrawn from Laclede's underground storage fields located in St. Louis and St. Charles Counties. These fields are capable of providing up to 357,000 MMBtu of natural gas withdrawals on a peak day and annual withdrawals of about 5.5 million MMBtu based on the inventory level that LG plans to maintain.

Liquid propane is transported through LG's pipeline from propane supply terminal facilities at Wood River and Cahokia, IL, to Laclede's 800,000-barrel propane storage facilities in St. Louis. The propane is ultimately vaporized and used during periods of peak demand.

In February 1998, LG filed with the Missouri Public Service Commission (MPSC) for an annual rate increase totaling $25.4 million. On October 15, 1998, the MPSC approved a settlement of the matter stipulating that the rates charged by LG to the vast majority of its customers would not change, but that Laclede would be permitted to record substantially lower depreciation and pension costs and to use cost-deferral mechanisms and apply for certain cost recoveries in the future.

Per Share Data ($) (Year Ended Sep. 30)	1998	1997	1996	1995	1994	1993	1992	1991	1990	1989
Tangible Bk. Val.	14.62	14.23	13.68	13.00	12.39	12.13	11.76	11.79	11.72	11.73
Earnings	1.58	1.84	1.87	1.27	1.42	1.61	1.17	1.28	1.08	1.45
Dividends	1.32	1.30	1.26	1.24	1.22	1.22	1.20	1.20	1.17	1.15
Payout Ratio	84%	71%	67%	98%	86%	75%	103%	94%	109%	79%
Prices - High	27⅞	26⅝	24⅞	23⅛	25⅝	24⅞	20½	18¼	18	17
- Low	22⅝	20¼	20	18⅝	20¼	20	17	15	14¼	14
P/E Ratio - High	18	16	13	18	18	15	18	15	17	12
- Low	14	11	11	14	14	12	15	12	13	10
Income Statement Analysis (Million $)										
Revs.	547	603	545	432	524	504	418	438	471	492
Depr.	25.3	25.9	25.0	23.7	19.3	18.7	18.0	17.0	16.4	15.9
Maint.	18.7	18.2	16.1	17.5	18.4	16.7	15.4	14.3	14.9	13.5
Fxd. Chgs. Cov.	3.0	3.6	3.7	2.7	3.1	3.5	2.7	3.1	2.8	3.6
Constr. Credits	Nil	Nil	Nil	0.3	0.3	0.3	0.4	0.2	0.1	0.1
Eff. Tax Rate	36%	36%	36%	33%	36%	39%	32%	36%	24%	27%
Net Inc.	27.9	32.5	32.8	20.9	22.2	25.2	18.3	20.0	16.9	22.7
Balance Sheet & Other Fin. Data (Million $)										
Gross Prop.	868	822	780	746	710	676	644	606	572	547
Cap. Exp.	47.3	42.8	41.2	45.6	39.2	40.9	44.7	38.3	29.2	28.3
Net Prop.	524	497	452	434	412	390	367	339	316	302
Capitalization:										
LT Debt	179	154	179	154	154	166	147	165	130	117
% LT Debt	33	38	43	40	44	46	44	47	41	39
Pfd.	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
% Pfd.	0.40	0.50	0.50	0.50	0.60	0.60	0.60	0.60	0.60	0.70
Common	257	250	241	227	195	190	184	184	183	183
% Common	59	62	57	59	56	53	55	53	58	61
Total Cap.	548	407	422	383	436	403	374	388	360	340
% Oper. Ratio	88.2	91.8	91.5	91.1	92.6	92.0	92.3	92.6	93.2	93.2
% Earn. on Net Prop.	9.1	10.2	10.5	9.1	9.4	10.7	9.1	9.9	10.3	11.3
% Return On Revs.	5.1	5.4	6.0	4.8	4.2	5.0	4.4	4.6	3.6	4.6
% Return On Invest. Capital	9.4	13.9	13.4	10.9	9.2	10.7	8.9	9.4	8.8	10.1
% Return On Com. Equity	11.0	13.2	14.0	9.9	11.5	13.4	9.9	10.8	9.2	12.5

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs. Bold denotes diluted EPS (FASB 128)-prior periods restated. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked.

Office—720 Olive St., St. Louis, MO 63101. Tel—(314) 342-0500. Website—http://www.lacledegas.com Chrmn & CEO—R. O. Jaudes. Pres & COO—D. H. Yaeger. Secy—M. C. Kullman. SVP-Fin & CFO—G. T. McNeive Jr. Treas—R. L. Krutzman. Dirs—R. E. Beumer, A. B. Craig III, H. Givens Jr., C. R. Holman, R. C. Jaudes, M. A. Krey, W. E. Nasser, R. P. Stupp, H. E. Trusheim. Transfer Agent & Registrar—ChaseMellon Shareholder Services, South Hackensack, NJ. Incorporated—in Missouri in 1857. Empl— 2,064. S&P Analyst: S.A.H.

STANDARD
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STOCK REPORTS

New Jersey Resources

NYSE Symbol **NJR**
In S&P SmallCap 600

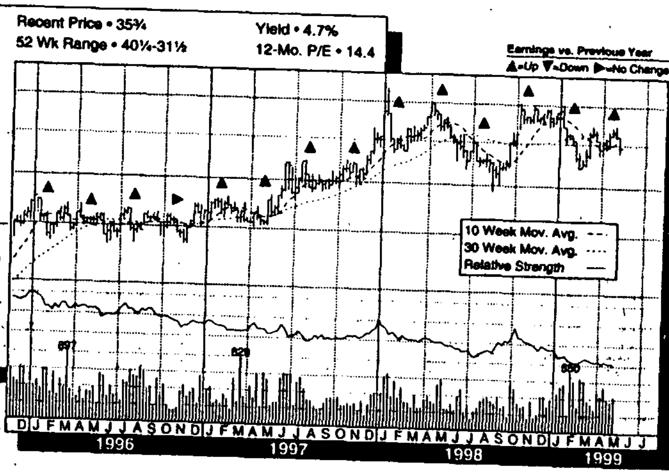
08-MAY-99 Industry: Natural Gas

Summary: Through New Jersey Natural Gas Co., this utility holding company supplies gas to over 385,000 customers in central and northern New Jersey.

Quantitative Evaluations
Outlook (1 Lowest—5 Highest)
• 2
Fair Value
• 37⅛
Risk
• Low
Earn./Div. Rank
• A-

Technical Eval.
• Bearish since 2/99
Rel. Strength Rank (1 Lowest—99 Highest)
• 32
Insider Activity
• NA

Recent Price • 35¾
52 Wk Range • 40¼-31½
Yield • 4.7%
12-Mo. P/E • 14.4



Business Profile - 02-MAR-99

NJR's goal is to continue to grow without increasing its base rates in order to remain competitive as the utility industry transitions to a more market-based environment. In both 1999 and 2000, the company's aim is to add 11,800 to 12,000 new customers, and convert an additional 950 existing customers each year to natural gas heat. Achieving these objectives would represent a customer growth rate of more than 3% and result in a sales increase of about 1.9 billion cubic feet per year, assuming normal weather and average use, and increase gross margin under present rates by some $5.5 million per year.

Operational Review - 02-MAR-99

Revenues in the first quarter of FY 99 (Sep.) were up 11%, year to year, primarily reflecting growth in the customer base and higher fuel and capacity management sales. Operating expenses rose at a slightly more rapid rate, with the largest increases in gas purchases and state income taxes. Operating income was up 6.4%. With lower other income and interest charges, net income rose 6.6%, to $15,152,000 ($0.84 a share), from $14,216,000 ($0.79).

Stock Performance - 07-MAY-99

In the past 30 trading days, NJR's shares have increased 0.70%, compared to a 5% rise in the S&P 500. Average trading volume for the past five days was 21,300 shares, compared with the 40-day moving average of 20,541 shares.

Key Stock Statistics

Dividend Rate/Share	1.68	Shareholders	18,514
Shs. outstg. (M)	17.9	Market cap. (B)	$0.640
Avg. daily vol. (M)	0.022	Inst. holdings	35%
Tang. Bk. Value/Share	15.46		
Beta	0.43		

Value of $10,000 invested 5 years ago: $ 18,079

Fiscal Year Ending Sep. 30

	1999	1998	1997	1996	1995	1994
Revenues (Million $)						
1Q	244.6	220.4	188.6	159.7	126.0	136.2
2Q	327.3	266.6	285.4	233.9	197.2	222.8
3Q	—	113.4	121.2	94.46	74.36	75.61
4Q	—	109.9	101.4	60.40	56.98	64.22
Yr.	—	710.3	696.5	548.5	454.6	498.8
Earnings Per Share ($)						
1Q	0.84	0.79	0.71	0.69	0.65	0.62
2Q	1.69	1.60	1.58	1.50	1.46	1.37
3Q	—	0.16	0.14	0.12	0.07	0.19
4Q	—	-0.22	-0.23	-0.25	-0.25	-0.28
Yr.	—	2.33	2.21	2.06	1.93	1.89

Next earnings report expected: late July

Dividend Data (Dividends have been paid since 1951.)

Amount ($)	Date Decl.	Ex-Div. Date	Stock of Record	Payment Date
0.410	May. 14	Jun. 11	Jun. 15	Jul. 01 '98
0.410	Jul. 07	Sep. 11	Sep. 15	Oct. 01 '98
0.420	Nov. 20	Dec. 11	Dec. 15	Jan. 04 '99
0.420	Jan. 26	Mar. 11	Mar. 15	Apr. 01 '99

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New Jersey Resources Corporation

08-MAY-99

Business Summary - 02-MAR-99

This energy services holding company provides retail and wholesale natural gas and related energy services to customers from the Gulf Coast to New England. Its principal subsidiary, New Jersey Natural Gas Co., provides regulated natural gas service to more than 385,000 customers in central and northern New Jersey. Revenues by customer class broke down as follows in FY 98 (Sep.):

	Revs.
Residential	53%
Commercial & other	11%
Firm transportation	3%
Interruptible	2%
Off-System	29%
Appliance service	2%

New Jersey Natural Gas's service territory is primarily suburban, with a wide range of cultural and recreational activities, highlighted by about 100 miles of New Jersey seacoast. It is in proximity to New York, Philadelphia and the metropolitan areas of northern New Jersey and is accessible through a network of major roadways and mass transportation. These factors contributed to the company adding 11,819, 11,708 and 10,978 new customers in FY 98, FY 97 and FY 96, respectively. This annual growth rate of 3% is expected to continue.

NJNG also participates in "capacity release" and "off-system" sales programs whereby NJNG releases some of the capacity it has secured on interstate pipelines and sells excess gas supplies when demand is not at its peak. These programs reach wholesale customers as far away as Texas, well beyond NJNG's local franchise area. Effective October 1, 1998, through December 31, 2001, the company will retain 15% of the gross margin from off-system and capacity release sales, down from 20% prior to September 30, 1998. Off-system sales totaled 62.2 billion cubic feet and generated $2.6 million of gross margin in 1998.

The New Jersey Natural Energy Co. (NJNE) unit was formed in 1996 to participate in the unregulated marketing of natural gas and energy services. NJNE must compete for its retail gas customers against a score of other marketers; as of the end of FY 98, NJNE supplied gas to some 7,502 retail customers.

The company purchases a diverse gas supply portfolio consisting of long-term (over seven months), winter-term (for the five winter months) and short-term contracts. In 1998, the company purchased gas from 78 suppliers under contracts ranging from one month to 12 years. The company has five long-term firm gas purchase contracts and purchased about 12% of its gas in 1998 from Alberta Northeast Gas.

Per Share Data ($) (Year Ended Sep. 30)	1998	1997	1996	1995	1994	1993	1992	1991	1990	1989
Tangible Bk. Val.	15.46	15.34	15.12	14.55	14.48	14.72	14.16	12.85	13.27	13.66
Earnings	2.33	2.22	2.06	1.93	1.89	1.72	1.64	0.83	0.97	1.45
Dividends	1.64	1.60	1.55	1.52	1.52	1.52	1.52	1.50	1.44	1.36
Payout Ratio	70%	72%	75%	98%	80%	88%	93%	181%	148%	94%
Prices - High	40¼	42	29⅞	30½	27⅞	29½	25⅛	21⅛	20⅞	21½
- Low	31½	26⅛	26⅝	21½	19¾	24	18¼	17	17⅝	17⅞
P/E Ratio - High	17	19	15	16	14	17	15	25	22	15
- Low	14	13	13	11	10	14	11	20	18	12
Income Statement Analysis (Million $)										
Revs.	710	697	549	455	499	455	412	835	325	330
Depr.	27.8	25.8	23.2	23.0	27.6	25.4	24.3	21.7	18.3	16.1
Maint.	Nil	Nil	NA	NA	NA	NA	6.4	7.3	8.0	6.5
Fxd. Chgs. Cov.	4.3	3.8	3.7	2.8	3.0	2.8	2.5	1.7	1.9	2.3
Constr. Credits	Nil	Nil	Nil	Nil	Nil	3.2	3.3	3.6	2.6	2.2
Eff. Tax Rate	36%	34%	34%	32%	30%	30%	31%	31%	31%	32%
Net Inc.	41.8	39.9	37.1	33.9	33.9	26.5	23.5	11.3	13.0	16.4
Balance Sheet & Other Fin. Data (Million $)										
Gross Prop.	920	878	856	786	859	831	770	725	673	588
Cap. Exp.	44.5	47.0	56.1	53.8	58.6	70.4	47.6	57.4	83.2	64.8
Net Prop.	680	659	655	596	640	633	592	567	533	463
Capitalization:										
LT Debt	327	291	303	352	324	311	252	263	228	209
% LT Debt	51	49	51	57	54	54	49	55	54	52
Pfd.	20.8	20.8	21.0	21.0	22.1	22.3	32.6	32.9	13.2	13.4
% Pfd.	3.20	3.50	3.50	3.30	3.70	3.90	6.30	6.90	3.10	3.30
Common	291	278	274	259	250	248	231	179	179	180
% Common	48	47	46	41	42	43	45	38	43	45
Total Cap.	722	591	598	632	661	642	577	529	475	451
% Oper. Ratio	91.5	91.2	89.1	86.9	89.2	89.0	88.7	89.6	89.5	89.5
% Earn. on Net Prop.	9.1	9.4	9.5	9.5	8.7	8.2	8.0	6.3	6.8	8.1
% Return On Revs.	5.9	5.7	6.8	7.4	6.8	6.3	5.7	3.4	4.0	5.0
% Return On Invest. Capital	9.6	10.4	11.5	10.8	8.6	8.4	8.6	7.0	7.4	8.8
% Return On Com. Equity	14.7	14.5	13.9	13.3	13.4	11.9	11.4	6.3	7.2	10.4

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs. Bold denotes diluted EPS (FASB 128)-prior periods restated. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked.

Office—1415 Wyckoff Road, P.O. Box 1468, Wall, NJ 07719. Tel—(732) 938-1480. Website—http://www.njresources.com Chrmn, [illegible] Aversano, B. G. Coe, L. S. Coleman, L. M. Downes, J. B. Foster, H. F. Gluck, L. D. Johnson, D. K. Light, G. G. [illegible] J. J. Unidos, Jr., G. W. Wolf, G. R. Zoffinger. Transfer Agent & Registrar—Bank of Boston. Incorporated—in New Jersey in 1922. Empl— 791. S&P Analyst: P.L.H.
CEO—L. M. Downes. SVP & CFO—G. C. Lockwood. SVP & Secy—O. J. Harden. Investor Contact—Dennis Puma (732-938-1229). Dirs—

STANDARD
&POOR'S
STOCK REPORTS

Piedmont Natural Gas

NYSE Symbol **PNY**
In S&P SmallCap 600

08-MAY-99

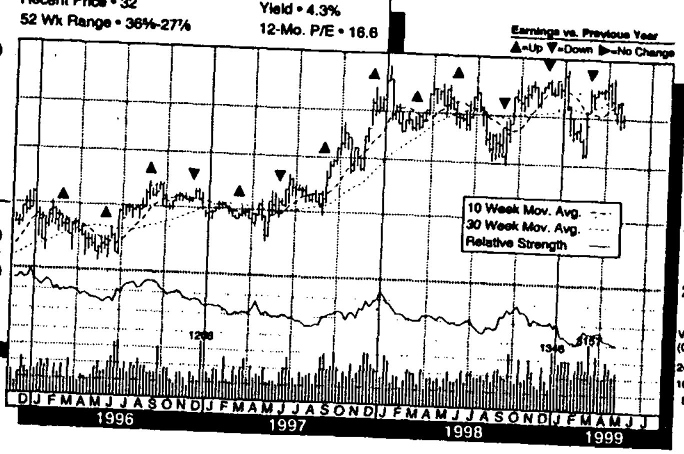
Industry:
Natural Gas

Summary: This company is primarily engaged in the transportation and sale of natural gas to customers in North Carolina, South Carolina and Tennessee.

Quantitative Evaluations
Outlook
(1 Lowest—5 Highest)
• 1 -
Fair Value
• 31⅛
Risk
• Low
Earn./Div. Rank
• A-

Technical Eval.
• Bearish since 2/99
Rel. Strength Rank
(1 Lowest—99 Highest)
• 28
Insider Activity
• Favorable

Recent Price • 32
52 Wk Range • 36⅛-27⅞
Yield • 4.3%
12-Mo. P/E • 16.6



Business Profile - 17-MAR-99

Piedmont is the second largest gas utility in the Southeast. With its 5%-6% annual customer growth rate, the company continues to be one of the fastest-growing natural gas distributors in the U.S., adding customers at a rate three times the industry average. PNY kept pace in FY 98 (Oct.) by adding 31,400 natural gas customers. However, natural gas and propane sales have been soft in recent periods, reflecting warmer than normal weather.

Operational Review - 17-MAR-99

Operating revenues in the first quarter of FY 99 (Oct.) fell 18%, year to year, primarily reflecting weather that was 19% warmer than normal and 17% warmer than the similar prior year period; total system throughput was 43.2 million dekatherms, down from 49.7 million dekatherms. Net income was down 1.7%, to $40,564,000 ($1.31 a share, based on 1.8% more shares) from $41,249,000 ($1.35).

Stock Performance - 07-MAY-99

In the past 30 trading days, PNY's shares have declined 8%, compared to a 5% rise in the S&P 500. Average trading volume for the past five days was 38,180 shares, compared with the 40-day moving average of 51,184 shares.

Key Stock Statistics

Dividend Rate/Share	1.38	Shareholders	19,100
Shs. outstg. (M)	30.9	Market cap. (B)	$0.990
Avg. daily vol. (M)	0.041	Inst. holdings	24%
Tang. Bk. Value/Share	14.83		
Beta	0.38		

Value of $10,000 invested 5 years ago: $ 20,124

Fiscal Year Ending Oct. 31

	1999	1998	1997	1996	1995	1994
Revenues (Million $)						
1Q	255.7	313.3	312.5	239.2	202.5	233.1
2Q	—	261.5	259.3	259.5	179.4	204.8
3Q	—	103.0	104.0	95.74	61.65	70.64
4Q	—	87.52	99.7	90.68	61.71	66.80
Yr.	—	765.3	775.5	685.1	505.2	575.4
Earnings Per Share ($)						
1Q	1.31	1.35	1.26	1.18	1.13	1.06
2Q	—	1.16	1.08	1.12	0.87	0.87
3Q	—	-0.20	-0.19	-0.28	-0.31	-0.27
4Q	—	-0.33	-0.32	-0.33	-0.18	-0.30
Yr.	—	1.96	1.79	1.66	1.45	1.36

Next earnings report expected: early June
Dividend Data (Dividends have been paid since 1956.)

Amount ($)	Date Decl.	Ex-Div. Date	Stock of Record	Payment Date
0.325	Jun. 05	Jun. 22	Jun. 24	Jul. 15 '98
0.325	Aug. 28	Sep. 22	Sep. 24	Oct. 15 '98
0.325	Dec. 04	Dec. 21	Dec. 23	Jan. 15 '99
0.345	Feb. 26	Mar. 23	Mar. 25	Apr. 15 '99

STANDARD
&POOR'S
STOCK REPORTS

Piedmont Natural Gas Company, Inc.

08-MAY-99

Business Summary - 17-MAR-99

This gas utility's growth has been fueled by the economic vibrancy of its service area, one of the fastest growing regions in the U.S. Piedmont Natural Gas (PNY), the second largest gas utility in the Southeast, transports and sells natural gas to more than 625,000 customers in the Piedmont region of the Carolinas (including Charlotte, Salisbury, Greensboro, Burlington, Winston-Salem, High Point and the Hickory area in NC, and Anderson, Greenville and Spartanburg, SC) and the metropolitan Nashville, TN, area. The company's propane market is in and adjacent to its natural gas market in all three states served. Revenues by customer class in recent fiscal years (Oct.) were:

	FY 98	FY 97	FY 96
Residential	42%	41%	43%
Commercial	25%	25%	26%
Industrial	21%	25%	27%
Other	12%	9%	4%

About 90% of new single family homes built in PNY's service area use natural gas, when available. The number of customers billed averaged 589,530 in FY 98 (560,694 in FY 97). Gas volumes delivered in FY 98 totaled 143.0 million dekatherms, versus 135.1 million dekatherms in FY 97.

PNY purchases or transports gas from eight interstate pipeline suppliers. At November 1, 1998, suppliers had contracted to provide a total of 604,600 dekatherms per day to PNY, with additional daily peaking capacity available.

The company's principal non-utility business is the sale of propane to 48,000 customers in its three state service region. Other non-utility operations include acquiring, marketing and arranging for the transportation of natural gas to large-volume purchasers. Non-utility activities accounted for 5% of revenues in FY 98 and 1% of total net income.

To meet demand of its expanding customer base, PNY has budgeted capital expenditures totaling $106.8 million for utility expansion and construction projects for FY 99, not including $2.3 million slated for non-utility projects. In addition, an estimated equity contribution of $18.7 million is required in mid-1999 in connection with the construction of a liquefied natural gas peak-demand facility in which the company has a stake. PNY also is seeking new markets for natural gas including a heating and cooling unit for residential and small business applications and natural gas powered vehicles (NGVs).

In September 1997, PNY acquired two independent propane companies: Lincoln Moore County Propane in Lynchburg, TN; and McCombs Propane Co. in Morganton, NC. The acquisitions added about 1.2 million gallons and 1,650 customers to the company's sales and customer base.

Per Share Data ($) (Year Ended Oct. 31)	1998	1997	1996	1995	1994	1993	1992	1991	1990	1989
Tangible Bk. Val.	14.83	13.81	12.96	12.20	11.36	10.79	10.24	9.62	9.10	8.67
Earnings	1.96	1.81	1.67	1.45	1.35	1.45	1.40	0.89	1.22	1.21
Dividends	1.28	1.21	1.15	1.08	1.02	0.96	0.91	0.87	0.83	0.79
Payout Ratio	65%	67%	69%	75%	76%	67%	65%	98%	68%	65%
Prices - High	36⅛	36⅛	25¾	24⅞	23⅞	26¾	20⅛	16⅞	14⅞	14¾
- Low	27⅞	22	20⅛	18¼	18	18¼	15⅛	13	12¾	11½
P/E Ratio - High	18	20	15	17	17	18	15	19	12	12
- Low	14	12	12	13	13	13	11	15	10	10
Income Statement Analysis (Million $)										
Revs.	765	776	685	505	575	553	480	412	404	421
Depr.	42.2	39.2	36.0	31.9	24.6	22.2	20.1	18.0	15.8	14.9
Maint.	14.7	16.2	15.8	16.4	15.5	15.0	13.3	13.1	11.6	10.1
Fxd. Chgs. Cov.	3.8	3.5	3.5	3.1	3.2	3.7	3.5	2.4	2.8	2.9
Constr. Credits	1.2	0.7	0.8	1.1	1.3	1.1	0.8	0.8	0.8	0.7
Eff. Tax Rate	39%	39%	39%	39%	36%	38%	38%	36%	37%	37%
Net Inc.	60.3	54.1	48.6	40.3	35.5	37.5	35.3	20.6	25.7	24.9
Balance Sheet & Other Fin. Data (Million $)										
Gross Prop.	1,372	1,284	1,168	1,075	978	877	796	723	658	591
Cap. Exp.	90.9	92.1	96.8	99	106	84.0	74.0	69.1	71.0	65.9
Net Prop.	991	942	862	801	735	655	593	538	486	434
Capitalization:										
LT Debt	371	381	391	361	313	278	231	221	174	186
% LT Debt	45	48	50	50	51	49	47	48	47	51
Pfd.	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
% Pfd.	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Common	458	420	386	355	302	285	265	239	196	181
% Common	55	52	50	50	49	51	53	52	53	49
Total Cap.	948	914	880	810	697	653	576	534	442	437
% Oper. Ratio	86.4	89.5	89.1	87.1	90.3	89.8	88.4	90.3	89.1	90.2
% Earn. on Net Prop.	9.4	9.2	9.0	5.2	8.0	9.1	9.4	7.8	9.5	10.1
% Return On Revs.	7.9	7.0	7.1	8.0	6.2	6.8	7.7	5.0	6.4	5.9
% Return On Invest. Capital	10.0	10.3	9.4	12.6	8.9	9.7	10.2	8.8	10.8	10.9
% Return On Com. Equity	13.7	13.4	13.1	12.3	12.1	13.7	14.0	9.5	13.6	14.2

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs. Bold denotes diluted EPS (FASB 128)-prior periods restated. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked.

Office—1915 Rexford Rd., Charlotte, NC 28211; P.O. Box 33068, Charlotte, NC 28233. Tel—(704) 364-3120. Website—www.piedmontng.com Chrmn & CEO—J. H. Maxheim. Pres & COO—W. F. Schiefer. SVP-Fin—D. J. Dzuricky. VP, Treas & Investor Contact—Ted C. Coble. VP & Secy—M. C. Ruegsegger. Dirs—J. W. Amos, C. M. Butler III, S. J. DiGiovanni, J. W. Harris, M. W. Helms, J. H. Maxheim, J. F. McNair III, N. R. McWherter, W. S. Montgomery Jr., D. S. Russell Jr., J. E. Simkins Jr. Transfer Agent & Registrar—Wachovia Bank of North Carolina, Winston-Salem. Incorporated—in North Carolina in 1994; previously incorporated in New York in 1950. Empl— 1,841. S&P Analyst: P.L.H.

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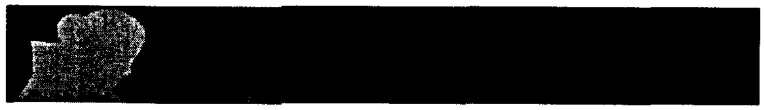

More Info: Quote | Chart | News | Profile | Research | SEC | Msgs | Insider

Historical Quotes NYSE:ATO

	Month	*Day*	*Year*		
Start Date:	Jun	06	99	(•) Daily	Ticker Symbol: ato
				( ) Weekly	
End Date:	Sep	07	99	( ) Monthly	Get Historical Data
				( ) Dividends	

Date	Open	High	Low	Close	Volume	Adj. Close*
3-Sep-99	25.125	25.4375	25	**25.375**	19,600	25.375
2-Sep-99	25	25.0625	25	**25**	254,100	25
1-Sep-99	25.0625	25.1875	25	**25**	14,700	25
31-Aug-99	25	25.25	25	**25.0625**	12,000	25.0625
30-Aug-99	25.3125	25.3125	25	**25.0625**	23,300	25.0625
27-Aug-99	25.0625	25.8125	25	**25.375**	31,900	25.375
26-Aug-99	25.625	25.625	24.875	**25.0625**	16,800	25.0625
25-Aug-99	24.8125	25.75	24.8125	**25.75**	1,372,000	25.75
24-Aug-99	25	25	24.75	**24.9375**	95,000	24.9375
23-Aug-99	26.1875	26.1875	25.25	**25.25**	17,400	25.25
23-Aug-99	$0.28 Cash Dividend					
20-Aug-99	25.50	26.375	25.50	**26.375**	46,000	26.10
19-Aug-99	25.25	25.3125	25.1875	**25.3125**	11,400	25.0486
18-Aug-99	25.1875	25.4375	25	**25.4375**	25,000	25.1723
17-Aug-99	25	25.1875	24.875	**25.1562**	136,600	24.894
16-Aug-99	24.75	25	24.625	**25**	15,900	24.7393
13-Aug-99	24.6875	24.8125	24.4375	**24.75**	215,500	24.4919
12-Aug-99	24.3125	24.5625	24.3125	**24.5625**	20,600	24.3064
11-Aug-99	24.875	24.875	24.375	**24.5625**	22,000	24.3064
10-Aug-99	24.4375	24.875	24.4375	**24.875**	27,500	24.6156
9-Aug-99	24.9375	24.9375	24.50	**24.5625**	59,900	24.3064
6-Aug-99	25	25	24.75	**24.9375**	31,800	24.6775

16-Jun-99	25.1875	25.875	25.1875	**25.875**	11,500	25.6052
15-Jun-99	24.875	25.375	24.375	**25.375**	13,700	25.1104
14-Jun-99	25.25	25.25	24.8125	**24.8125**	14,800	24.5538
11-Jun-99	25.0625	25.50	24.8125	**25**	30,700	24.7393
10-Jun-99	25.75	25.75	24.8125	**25.1875**	58,700	24.9249
9-Jun-99	26	26	25.75	**25.875**	8,000	25.6052
8-Jun-99	25.875	26	25.6875	**26**	27,800	25.7289
7-Jun-99	26.3125	26.3125	25.75	**25.875**	22,200	25.6052

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* adjusted for dividends and splits,please see FAQ.

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More Info: Quote

Historical Quotes NYSE:EGN

	Month	Day	Year
Start Date:	Jun	06	99
End Date:	Sep	07	99

◉ Daily
○ Weekly
○ Monthly
○ Dividends

Ticker Symbol: egn

Get Historical Data

Date	Open	High	Low	Close	Volume	Adj. Close*
3-Sep-99	19.1875	19.875	19.1875	**19.875**	19,700	19.875
2-Sep-99	19.375	19.50	19.25	**19.25**	69,400	19.25
1-Sep-99	19	19.4375	18.9375	**19.4375**	25,900	19.4375
31-Aug-99	19	19.125	18.875	**18.875**	43,400	18.875
30-Aug-99	19.0625	19.125	18.8125	**18.875**	89,700	18.875
27-Aug-99	19	19.125	19	**19.0625**	45,700	19.0625
26-Aug-99	19.0625	19.1875	19	**19**	18,700	19
25-Aug-99	18.75	19.3125	18.75	**19.125**	35,500	19.125
24-Aug-99	19.0625	19.25	18.875	**18.875**	37,500	18.875
23-Aug-99	18.75	19.25	18.75	**19.0625**	71,500	19.0625
20-Aug-99	18.9375	19	18.75	**18.875**	51,300	18.875
19-Aug-99	18.375	19	18.375	**19**	94,300	19
18-Aug-99	18.4375	18.4375	18.125	**18.25**	10,500	18.25
17-Aug-99	18.25	18.50	18.1875	**18.4062**	44,900	18.4062
16-Aug-99	18.4375	18.4375	18.125	**18.1875**	42,800	18.1875
13-Aug-99	18.50	18.50	18.25	**18.4375**	22,600	18.4375
12-Aug-99	18	18.875	18	**18.5625**	35,900	18.5625
11-Aug-99	18	18	17.50	**18**	161,800	18
11-Aug-99	$0.17 Cash Dividend					
10-Aug-99	18.625	18.75	18.3125	**18.625**	33,500	18.46
9-Aug-99	18.9375	18.9375	18.75	**18.75**	39,100	18.5839
6-Aug-99	18.875	18.9375	18.75	**18.875**	49,000	18.7078

16-Jun-99	19.25	19.375	19	**19**	27,100	18.8317
15-Jun-99	18.875	19.125	18.625	**19.125**	50,900	18.9556
14-Jun-99	18.8125	18.875	18.625	**18.75**	71,500	18.5839
11-Jun-99	18.625	19.1875	18.625	**18.6875**	27,200	18.5219
10-Jun-99	19.125	19.25	18.875	**18.875**	130,500	18.7078
9-Jun-99	19.625	19.9375	19.125	**19.1875**	39,300	19.0175
8-Jun-99	19.3125	19.75	19.125	**19.50**	87,900	19.3272
7-Jun-99	18.4375	19.25	18.4375	**19.1875**	34,500	19.0175

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* adjusted for dividends and splits,please see FAQ.

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Historical Quotes NYSE:LG

	Month	Day	Year		
Start Date:	Jun	06	99	◉ Daily	Ticker Symbol: lg
End Date:	Sep	07	99	○ Weekly	Get Historical Data
				○ Monthly	
				○ Dividends	

Date	Open	High	Low	Close	Volume	Adj. Close*
3-Sep-99	22.50	22.75	22.375	**22.625**	8,700	22.625
2-Sep-99	22.6875	22.6875	22.25	**22.3125**	17,600	22.3125
1-Sep-99	21.625	23	21.5625	**22.875**	23,900	22.875
31-Aug-99	21.625	22	21.5625	**21.6875**	21,800	21.6875
30-Aug-99	22.125	22.125	21.625	**21.625**	19,800	21.625
27-Aug-99	22.9375	22.9375	22.125	**22.1875**	16,700	22.1875
26-Aug-99	22.50	22.875	22.375	**22.8125**	18,100	22.8125
25-Aug-99	22	22.50	22	**22.375**	18,100	22.375
24-Aug-99	22.125	22.25	22.0625	**22.125**	11,800	22.125
23-Aug-99	22	22.25	21.8125	**22.25**	16,500	22.25
20-Aug-99	21.75	22	21.75	**22**	10,700	22
19-Aug-99	21.6875	22	21.6875	**21.875**	11,900	21.875
18-Aug-99	21.75	21.9375	21.5625	**21.625**	22,800	21.625
17-Aug-99	22	22	21.5625	**21.625**	22,600	21.625
16-Aug-99	22.375	22.375	21.6875	**21.75**	16,100	21.75
13-Aug-99	22.5625	22.5625	22.25	**22.375**	3,700	22.375
12-Aug-99	22.5625	22.9375	22.50	**22.625**	10,800	22.625
11-Aug-99	22.3125	22.625	21.875	**22.625**	14,400	22.625
10-Aug-99	22.875	23.25	22.125	**22.50**	25,500	22.50
9-Aug-99	23.3125	23.3125	22.75	**22.75**	20,700	22.75
6-Aug-99	23.125	23.375	23.125	**23.375**	9,100	23.375
5-Aug-99	23.4375	23.4375	22.75	**23.25**	13,200	23.25

15-Jun-99	22	22.625	22	**22.4375**	25,600	22.4375
14-Jun-99	22.125	22.375	21.875	**22.1875**	26,900	22.1875
11-Jun-99	21.5625	22	21.5625	**22**	16,000	22
10-Jun-99	21.75	22	21.50	**21.625**	10,400	21.625
9-Jun-99	22.125	22.25	21.5625	**21.6875**	13,200	21.6875
9-Jun-99	$0.34 Cash Dividend					
8-Jun-99	22.1875	22.375	22	**22.375**	22,400	22.04
7-Jun-99	22.1875	22.1875	21.75	**22.1875**	22,500	21.8553

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* adjusted for dividends and splits,please see FAQ.

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Historical Quotes NYSE:NJR

	Month	Day	Year
Start Date:	Jun	06	99
End Date:	Sep	07	99

◉ Daily
○ Weekly
○ Monthly
○ Dividends

Ticker Symbol: njr

Get Historical Data

Date	Open	High	Low	Close	Volume	Adj. Close*
3-Sep-99	39	39.3125	39	**39.25**	28,600	39.25
2-Sep-99	38.8125	39.375	38.625	**38.875**	24,900	38.875
1-Sep-99	38.50	39.125	38.50	**38.875**	18,100	38.875
31-Aug-99	38.9375	39	38.5625	**38.75**	18,600	38.75
30-Aug-99	39.4375	39.4375	38.9375	**39.0625**	12,100	39.0625
27-Aug-99	39.375	39.75	39.125	**39.375**	12,500	39.375
26-Aug-99	40	40.125	39.5625	**39.625**	5,600	39.625
25-Aug-99	39.6875	40.125	39.4375	**40.125**	20,300	40.125
24-Aug-99	39.9375	39.9375	39.1875	**39.8125**	13,700	39.8125
23-Aug-99	39.875	40	39.50	**39.8125**	11,100	39.8125
20-Aug-99	39.875	40	39.3125	**40**	15,700	40
19-Aug-99	39.8125	40	39.375	**39.75**	18,600	39.75
18-Aug-99	40	40	39.125	**39.9375**	18,500	39.9375
17-Aug-99	39.9375	40.125	39.625	**40**	25,200	40
16-Aug-99	39.75	39.9375	39.625	**39.9375**	13,800	39.9375
13-Aug-99	39.375	39.75	39.125	**39.625**	9,200	39.625
12-Aug-99	39.125	39.75	39.0625	**39.50**	15,400	39.50
11-Aug-99	39.0625	39.125	39.0625	**39.125**	20,200	39.125
10-Aug-99	39.4375	39.4375	38.875	**39.125**	22,500	39.125
9-Aug-99	39.5625	39.5625	39.0625	**39.5625**	363,900	39.5625
6-Aug-99	38.625	39.50	38.625	**39.50**	26,500	39.50
5-Aug-99	38.875	38.9375	38.625	**38.6875**	29,000	38.6875

15-Jun-99	37.125	38.25	37.125	**38**	34,700	38
14-Jun-99	37.375	37.375	37	**37**	22,300	37
11-Jun-99	37.75	37.8125	37.50	**37.50**	77,400	37.50
11-Jun-99	$0.42 Cash Dividend					
10-Jun-99	37.9375	38.125	37.8125	**38.0625**	19,300	37.6425
9-Jun-99	38	38	37.8125	**37.9375**	10,300	37.5189
8-Jun-99	37.6875	38	37.6875	**38**	13,200	37.5807
7-Jun-99	37.9375	38	37.50	**37.8125**	15,600	37.3953

Download Spreadsheet Format

* adjusted for dividends and splits,please see FAQ.

YAHOO! FINANCE

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Historical Quotes NYSE:PNY

	Month	Day	Year
Start Date:	Jun	06	99
End Date:	Sep	07	99

◉ Daily
○ Weekly
○ Monthly
○ Dividends

Ticker Symbol: pny

Get Historical Data

Date	Open	High	Low	Close	Volume	Adj. Close*
3-Sep-99	32.625	33.1875	32.625	**33.1875**	15,100	33.1875
2-Sep-99	33.125	33.125	32.50	**32.5625**	16,800	32.5625
1-Sep-99	33.50	33.8125	33.25	**33.375**	15,700	33.375
31-Aug-99	33.25	33.5625	33	**33.5625**	38,700	33.5625
30-Aug-99	33	33.125	33	**33.125**	30,500	33.125
27-Aug-99	33.625	33.625	33.3125	**33.375**	11,800	33.375
26-Aug-99	33.75	33.875	33.50	**33.6875**	10,300	33.6875
25-Aug-99	33.6875	34	33.4375	**33.875**	19,200	33.875
24-Aug-99	33.625	33.625	33.3125	**33.5625**	16,400	33.5625
23-Aug-99	33.3125	34	33.3125	**33.75**	13,000	33.75
20-Aug-99	33.5625	33.8125	33.25	**33.50**	16,000	33.50
19-Aug-99	33.875	33.875	33.4375	**33.6875**	10,400	33.6875
18-Aug-99	33.625	34.125	33.50	**34**	13,300	34
17-Aug-99	33.75	33.8125	33.3125	**33.7812**	18,900	33.7812
16-Aug-99	33.125	33.75	33	**33.625**	17,300	33.625
13-Aug-99	33.0625	33.0625	32.9375	**33.0625**	20,300	33.0625
12-Aug-99	32.9375	33.25	32.9375	**32.9375**	8,000	32.9375
11-Aug-99	33.1875	33.25	32.75	**33**	19,200	33
10-Aug-99	33.1875	33.4375	32.875	**33.375**	52,300	33.375
9-Aug-99	33.3125	33.3125	33	**33.3125**	32,500	33.3125
6-Aug-99	33.75	33.75	32.875	**33.375**	44,000	33.375
5-Aug-99	33.75	33.875	33.4375	**33.6875**	35,800	33.6875

16-Jun-99	31.875	32.125	31.125	**31.875**	81,900	31.5276
15-Jun-99	31.375	31.75	31.125	**31.625**	35,500	31.2804
14-Jun-99	31.1875	31.2188	30.75	**31.125**	38,700	30.7858
11-Jun-99	31.75	31.75	31.0625	**31.0625**	10,900	30.724
10-Jun-99	31.75	32	31.625	**31.875**	14,500	31.5276
9-Jun-99	32	32	31.50	**31.875**	24,000	31.5276
8-Jun-99	31.625	32	31	**32**	41,900	31.6513
7-Jun-99	31.75	32.0625	31.625	**31.625**	21,700	31.2804

Download Spreadsheet Format

* adjusted for dividends and splits,please see FAQ.

Questions or Comments?

 All Financial Information
ATMOS ENERGY CORP

AUDITOR CHANGE: NA
AUDITOR: ERNST & YOUNG (SOURCE: 10-K)
AUDITOR'S REPORT: UNQUALIFIED

BALANCE SHEET
ANNUAL ASSETS (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
CASH	4,735	6,016	11,134
RECEIVABLES	34,887	71,217	103,415
INVENTORIES	15,219	12,333	13,895
OTHER CURRENT ASSETS	52,539	54,139	46,159
TOTAL CURRENT ASSETS	107,380	143,705	174,603
PROP, PLANT & EQUIP	1,446,420	1,332,672	1,219,774
ACCUMULATED DEP	528,560	483,545	449,563
NET PROP & EQUIP	917,860	849,127	770,211
DEFERRED CHARGES	116,150	95,479	65,796
TOTAL ASSETS	1,141,390	1,088,311	1,010,610

ANNUAL LIABILITIES (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
NOTES PAYABLE	66,400	167,300	128,488
ACCOUNTS PAYABLE	44,742	62,626	80,321
CUR LONG TERM DEBT	57,783	15,201	16,679
ACCRUED EXPENSES	12,736	416	11,201
OTHER CURRENT LIAB	42,398	67,680	40,678
TOTAL CURRENT LIAB	224,059	313,223	277,367
DEFERRED CHARGES/INC	147,625	144,847	127,499
LONG TERM DEBT	398,548	302,981	276,162
TOTAL LIABILITIES	770,232	761,051	681,028
COMMON STOCK NET	152	148	146
CAPITAL SURPLUS	271,637	251,174	241,658
RETAINED EARNINGS	99,369	75,938	87,778
SHAREHOLDER EQUITY	371,158	327,260	329,582
TOT LIAB & NET WORTH	1,141,390	1,088,311	1,010,610

ANNUAL INCOME (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
NET SALES	848,208	906,835	886,691
COST OF GOODS	526,650	589,155	573,998
GROSS PROFIT	321,558	317,680	312,693
SELL GEN & ADMIN EXP	161,124	205,814	178,450
INC BEF DEP & AMORT	160,434	111,866	134,243
DEPRECIATION & AMORT	47,555	45,257	41,666
NON-OPERATING INC	9,771	5,122	3,567
INTEREST EXPENSE	35,579	33,595	31,677
INCOME BEFORE TAX	87,071	38,136	64,467
PROV FOR INC TAXES	31,806	14,298	23,316
NET INC BEF EX ITEMS	55,265	23,838	41,151
NET INCOME	55,265	23,838	41,151
OUTSTANDING SHARES	30,398	29,241	29,241

CASH FLOW PROVIDED BY OPERATING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
Net Income (Loss)	55,265	14,575
Depreciation/Amortization	47,555	39,970
Net Incr (Decr) Assets/Liabs	-9,727	6,160
Other Adjustments, Net	-1,442	8,044
Net Cash Prov (Used) by Oper	91,651	68,749

CASH FLOW PROVIDED BY INVESTING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
(Incr) Decr in Prop, Plant	-118,814	-121,123
Net Cash Prov (Used) by Inv	-118,814	-121,123

CASH FLOW PROVIDED BY FINANCING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
Issue (Purchase) of Equity	20,467	9,518
Issue (Repayment) of Debt	154,445	40,000
Incr (Decr) In Borrowing	-117,196	24,153
Dividends, Other Distribution	-31,834	-26,415
Net Cash Prov (Used) by Finan	25,882	47,256
Net Change in Cash or Equiv	-1,281	-5,118
Cash or Equiv at Year Start	6,016	11,134
Cash or Equiv at Year End	4,735	6,016

COMMENTS:
FIVE YEAR SUMMARY NOT GIVEN

PRICING INFORMATION

FOR WEEK ENDING:	07/31/1999
LATEST TRADE DATE:	07/30/1999
OUTSTANDING SHARES (000S):	30,869
VOLUME:	14,700
HIGH (OR ASKED):	25.000
LOW (OR BID):	24.813
CLOSE (OR AVERAGE):	25.000
MARKET VALUE (000S):	771,725

EARNINGS INFORMATION

FOR 12 MONTHS ENDING:	07/1999
EARNINGS PER SHARE:	1.34
PRICE/EARNINGS RATIO:	18.6

	CURRENT	PREVIOUS
INDICATED ANNUAL DIVIDEND:	1.100	
CURRENT DIVIDEND:	0.2750	0.2750
EX-DIVIDEND DATE:	05/21/1999	02/23/1999
RECORD DATE:	05/25/1999	02/25/1999
PAYABLE DATE:	06/10/1999	03/10/1999

I/B/E/S: EARNINGS ESTIMATES

--PERIOD--	------EPS EST'S------ MEAN	HIGH	LOW	# OF ESTS	CHG IN MEAN($): 1MONTH	3MONTH
FY 09/99	1.01	1.05	1.00	8	-0.33	-0.39
FY 09/00	1.98	2.15	1.70	9	-0.03	-0.05
QTR 06/99	-0.16	-0.15	-0.20	7	-0.19	-1.18
QTR 09/99	-0.33	-0.28	-0.36	6	-0.12	-0.38

EARNINGS PER SHARE ANNUAL GROWTH RATES

LAST 5 YEARS	8.9%	FY99/98	-45.0%	QTR 06/99	-507.1%
NEXT 5 YEARS	8.1%	FY00/99	95.3%	QTR 09/99	N-%

ATO ATMOS ENERGY CP		ESTD F/Y EPS:		
INDUSTRY CODE: GASUTI	PRICE	09/99	09/00	YIELD
GAS UTILITIES	25.00	1.01	1.98	4.4%

FY09/98 EPS:	1.84	DIVIDEND:	1.10	YIELD:	4.4%
FY09/99 P/E:	24.7	P/E REL S&P:	0.80	P/E REL IND:	0.93
FY09/00 P/E:	12.6	P/E REL S&P:	0.47	P/E REL IND:	0.54

	----FCST EPS GRWTH---- ATO	IND	S&P 500	---RELATIVE---- ATO TO IND	ATO TO S&P
FY99 VS FY98	-45.0%	14.2%	16.1%	-316	-279
FY00 VS FY99	95.3%	20.6%	17.1%	463	558
NEXT 5 YEARS	8.1%	11.6%	15.8%	70	51
LAST 5 YEARS	8.9%	8.1%	16.4%	77	56
P/E FY 1998	24.7	26.5	30.9	93	80
P/E FY 1999	12.6	23.3	26.6	54	47

DISTRIBUTION OF EPS ESTS. AS OF 07/30/99

```
              ATO        EPS FY 09/98    $  1.84
      FY 09/99 -   8 ESTS              FY 09/00 -   9 ESTS
       MEAN EPS $   1.01                MEAN EPS $   1.98

          N
          L
          L
          L                                     L
          L         L                           L         X
          L         L          X                X N     X X X
+--------+--------+--------+  +--------+--------+--------+
$0.95    1.00     1.05    1.1.60     1.80     2.00     2.20
X=EST R/L=RAISED/LOWERED PAST MO. N=NEW PAST MO. *=9+ ESTS
```

KEY ANNUAL FINANCIAL RATIOS

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
QUICK RATIO	0.18	0.25	0.41
CURRENT RATIO	0.48	0.46	0.63
SALES/CASH	179.14	150.74	79.64
SG & A/SALES	0.19	0.23	0.20
RECEIVABLES TURNOVER	24.31	12.73	8.57
RECEIVABLES DAYS SALES	14.81	28.27	41.99
INVENTORIES TURNOVER	55.73	73.53	63.81
INVENTORIES DAYS SALES	6.46	4.90	5.64
NET SALES/WORKING CAPITAL	-7.27	-5.35	-8.63
NET SALES/PLANT & EQUIPMENT	0.92	1.07	1.15
NET SALES/CURRENT ASSETS	7.90	6.31	5.08
NET SALES/TOTAL ASSETS	0.74	0.83	0.88
NET SALES/EMPLOYEES	386,780	338,498	536,738
TOTAL LIAB/TOTAL ASSETS	0.67	0.70	0.67
TOTAL LIAB/INVESTED CAPITAL	1.00	1.21	1.12
TOTAL LIAB/COMMON EQUITY	2.08	2.33	2.07
TIMES INTEREST EARNED	3.45	2.14	3.04
CURRENT DEBT/EQUITY	0.16	0.05	0.05
LONG TERM DEBT/EQUITY	1.07	0.93	0.84
TOTAL DEBT/EQUITY	1.23	0.97	0.89
TOTAL ASSETS/EQUITY	3.08	3.33	3.07
PRETAX INC/NET SALES	0.10	0.04	0.07
PRETAX INC/TOTAL ASSETS	0.08	0.04	0.06
PRETAX INC/INVESTED CAPITAL	0.11	0.06	0.11
PRETAX INC/COMMON EQUITY	0.23	0.12	0.20
NET INCOME/NET SALES	0.07	0.03	0.05
NET INCOME/TOTAL ASSETS	0.05	0.02	0.04
NET INCOME/INVESTED CAPITAL	0.07	0.04	0.07
NET INCOME/COMMON EQUITY	0.15	0.07	0.12

FINANCIAL STATEMENT TEXT:
NA; Assets Statement Full text to be supplied in future update.

NA; Liabilities Statement Full text to be supplied in future update.

NA; Income Statement Full text to be supplied in future update.

ENERGEN CORP

AUDITOR CHANGE: NA
AUDITOR: PRICEWATERHOUSECOOPERS, LLP (SOURCE: 10-K)
AUDITOR'S REPORT: UNQUALIFIED

BALANCE SHEET

ANNUAL ASSETS (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
CASH	103,231	105,402	17,074
RECEIVABLES	64,173	70,676	42,353
INVENTORIES	33,288	36,278	38,335
OTHER CURRENT ASSETS	17,761	29,809	17,533
TOTAL CURRENT ASSETS	218,453	242,165	115,295
PROP, PLANT & EQUIP	1,152,138	1,042,306	773,178
ACCUMULATED DEP	395,794	375,303	328,262
NET PROP & EQUIP	756,344	667,003	444,916
DEFERRED CHARGES	18,658	10,629	10,760
TOTAL ASSETS	993,455	919,797	570,971

ANNUAL LIABILITIES (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
NOTES PAYABLE	153,000	202,000	59,000
ACCOUNTS PAYABLE	33,533	49,196	32,659
CUR LONG TERM DEBT	7,209	1,855	1,805
ACCRUED EXPENSES	36,554	32,019	29,151
OTHER CURRENT LIAB	53,945	45,681	53,159
TOTAL CURRENT LIAB	284,241	330,751	175,774
DEFERRED CHARGES/INC	NA	NA	972
LONG TERM DEBT	372,782	279,602	195,545
OTHER LONG TERM LIAB	7,183	8,301	10,275
TOTAL LIABILITIES	664,206	618,654	382,566
COMMON STOCK NET	293	144	112
CAPITAL SURPLUS	198,676	188,643	89,635
RETAINED EARNINGS	131,153	112,356	98,658
TREASURY STOCK	873	NA	NA
SHAREHOLDER EQUITY	329,249	301,143	188,405
TOT LIAB & NET WORTH	993,455	919,797	570,971

ANNUAL INCOME (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
NET SALES	502,627	448,230	399,442
COST OF GOODS	322,427	303,512	290,710
GROSS PROFIT	180,200	144,718	108,732
SELL GEN & ADMIN EXP	37,716	33,044	28,817
INC BEF DEP & AMORT	142,484	111,674	79,915
DEPRECIATION & AMORT	80,999	59,688	41,118
NON-OPERATING INC	2,544	3,014	1,712
INTEREST EXPENSE	30,001	22,906	13,920
INCOME BEFORE TAX	34,028	32,094	26,589
PROV FOR INC TAXES	-2,221	3,097	5,048
NET INC BEF EX ITEMS	36,249	28,997	21,541
NET INCOME	36,249	28,997	21,541
OUTSTANDING SHARES	29,326	14,398	11,162

CASH FLOW PROVIDED BY OPERATING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
Net Income (Loss)	36,249	28,997
Depreciation/Amortization	80,999	59,688
Net Incr (Decr) Assets/Liabs	23,808	-21,299
Cash Prov (Used) by Disc Oper	NA	NA
Other Adjustments, Net	-17,433	-4,287
Net Cash Prov (Used) by Oper	123,623	63,099

CASH FLOW PROVIDED BY INVESTING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
(Incr) Decr in Prop, Plant	-174,578	-283,274
(Acq) Disp of Subs, Business	7,636	1,871
(Incr) Decr in Securities Inv	730	527
Other Cash Inflow (Outflow)	-96	1,030
Net Cash Prov (Used) by Inv	-166,308	-279,846

CASH FLOW PROVIDED BY FINANCING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
Issue (Purchase) of Equity	10,038	99,040
Issue (Repayment) of Debt	100,476	183,052
Incr (Decr) In Borrowing	-51,819	44,055
Dividends, Other Distribution	-18,181	-15,299
Other Cash Inflow (Outflow)	NA	NA
Net Cash Prov (Used) by Finan	40,514	310,848

Effect of Exchg Rate On Cash	NA	NA
Net Change in Cash or Equiv	-2,171	94,101
Cash or Equiv at Year Start	105,402	11,301
Cash or Equiv at Year End	103,231	105,402

COMMENTS:
FIVE YEAR SUMMARY NOT GIVEN

PRICING INFORMATION

FOR WEEK ENDING:	07/31/1999
LATEST TRADE DATE:	07/30/1999
OUTSTANDING SHARES (000S):	29,715
VOLUME:	52,700
HIGH (OR ASKED):	18.750
LOW (OR BID):	18.625
CLOSE (OR AVERAGE):	18.750
MARKET VALUE (000S):	557,156

EARNINGS INFORMATION

FOR 12 MONTHS ENDING:	07/1999
EARNINGS PER SHARE:	1.31
PRICE/EARNINGS RATIO:	14.3

	CURRENT	PREVIOUS
INDICATED ANNUAL DIVIDEND:	0.660	
CURRENT DIVIDEND:	0.1600	0.1600
EX-DIVIDEND DATE:	05/12/1999	02/10/1999
RECORD DATE:	05/14/1999	02/12/1999
PAYABLE DATE:	06/01/1999	03/01/1999

I/B/E/S: EARNINGS ESTIMATES

--PERIOD-	MEAN	HIGH	LOW	# OF ESTS	CHG IN MEAN($): 1MONTH	3MONTH
	------EPS EST'S------					
FY 09/99	1.28	1.32	1.25	6	0.01	0.01
FY 09/00	1.38	1.40	1.35	5	0.01	0.08
QTR 09/99	-0.30	-0.24	-0.35	4	-0.01	-1.62
QTR 12/99	0.16	0.16	0.15	2	0.00	0.10

EARNINGS PER SHARE ANNUAL GROWTH RATES

LAST 5 YEARS	18.0%	FY99/98	3.9%	QTR 09/99	N+%
NEXT 5 YEARS	7.2%	FY00/99	8.0%	QTR 12/99	19.2%

EGN ENERGEN CP

		PRICE	ESTD F/Y EPS: 09/99	09/00	YIELD
INDUSTRY CODE: GASUTI					
GAS UTILITIES		18.88	1.28	1.38	3.4%

FY09/98 EPS:	1.23	DIVIDEND:	0.64	YIELD:	3.4%
FY09/99 P/E:	14.8	P/E REL S&P:	0.48	P/E REL IND:	0.56
FY09/00 P/E:	13.7	P/E REL S&P:	0.51	P/E REL IND:	0.59

	----FCST EPS GRWTH---- EGN	IND	S&P 500	---RELATIVE---- EGN TO IND	EGN TO S&P
FY99 VS FY98	3.9%	14.2%	16.1%	28	24
FY00 VS FY99	8.0%	20.6%	17.1%	39	47
NEXT 5 YEARS	7.2%	11.6%	15.8%	62	46
LAST 5 YEARS	18.0%	8.1%	16.4%	155	114
P/E FY 1998	14.8	26.5	30.9	56	48
P/E FY 1999	13.7	23.3	26.6	59	51

DISTRIBUTION OF EPS ESTS. AS OF 07/30/99

EGN EPS FY 09/98 $ 1.23

FY 09/99 - 6 ESTS MEAN EPS $ 1.28

FY 09/00 - 5 ESTS MEAN EPS $ 1.38

```
          X                                                  R
          X         X                              X         X
          X         X  R                           X         X
+---------+---------+---------+  +---------+---------+---------+
$1.20    1.25      1.30   1.1.25      1.30      1.35     1.40
X=EST R/L=RAISED/LOWERED PAST MO. N=NEW PAST MO. *=9+ ESTS
```

KEY ANNUAL FINANCIAL RATIOS

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
QUICK RATIO	0.59	0.53	0.34
CURRENT RATIO	0.77	0.73	0.66
SALES/CASH	4.87	4.25	23.39
SG & A/SALES	0.08	0.07	0.07
RECEIVABLES TURNOVER	7.83	6.34	9.43
RECEIVABLES DAYS SALES	45.96	56.76	38.17
INVENTORIES TURNOVER	15.10	12.36	10.42
INVENTORIES DAYS SALES	23.84	29.14	34.55
NET SALES/WORKING CAPITAL	-7.64	-5.06	-6.60
NET SALES/PLANT & EQUIPMENT	0.66	0.67	0.90
NET SALES/CURRENT ASSETS	2.30	1.85	3.46
NET SALES/TOTAL ASSETS	0.51	0.49	0.70
NET SALES/EMPLOYEES	176,857	152,563	138,985
TOTAL LIAB/TOTAL ASSETS	0.67	0.67	0.67
TOTAL LIAB/INVESTED CAPITAL	0.95	1.07	1.00
TOTAL LIAB/COMMON EQUITY	2.02	2.05	2.03
TIMES INTEREST EARNED	2.13	2.40	2.91
CURRENT DEBT/EQUITY	0.02	0.01	0.01
LONG TERM DEBT/EQUITY	1.13	0.93	1.04
TOTAL DEBT/EQUITY	1.15	0.93	1.05
TOTAL ASSETS/EQUITY	3.02	3.05	3.03
PRETAX INC/NET SALES	0.07	0.07	0.07
PRETAX INC/TOTAL ASSETS	0.03	0.03	0.05
PRETAX INC/INVESTED CAPITAL	0.05	0.06	0.07
PRETAX INC/COMMON EQUITY	0.10	0.11	0.14
NET INCOME/NET SALES	0.07	0.06	0.05
NET INCOME/TOTAL ASSETS	0.04	0.03	0.04
NET INCOME/INVESTED CAPITAL	0.05	0.05	0.06
NET INCOME/COMMON EQUITY	0.11	0.10	0.11

FINANCIAL STATEMENT TEXT:
NA; Assets Statement Full text to be supplied in future update.

NA; Liabilities Statement Full text to be supplied in future update.

NA; Income Statement Full text to be supplied in future update.

LACLEDE GAS CO

AUDITOR CHANGE: NA
AUDITOR: DELOITTE & TOUCHE (SOURCE: 10-K)
AUDITOR'S REPORT: UNQUALIFIED

BALANCE SHEET
ANNUAL ASSETS (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
CASH	3,718	4,508	4,360
RECEIVABLES	46,055	47,932	45,578
INVENTORIES	73,404	75,000	77,058
OTHER CURRENT ASSETS	12,860	11,867	6,387
TOTAL CURRENT ASSETS	136,037	139,307	133,383
PROP, PLANT & EQUIP	833,685	792,661	780,001
ACCUMULATED DEP	343,100	325,088	327,836
NET PROP & EQUIP	490,585	467,573	452,165
INVEST & ADV TO SUBS	33,834	29,724	24,265
DEFERRED CHARGES	110,691	84,106	79,582
TOTAL ASSETS	771,147	720,710	689,395

ANNUAL LIABILITIES (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
ACCOUNTS PAYABLE	20,692	29,628	20,637
CUR LONG TERM DEBT	98,500	99,000	59,600
ACCRUED EXPENSES	20,314	18,253	21,217
OTHER CURRENT LIAB	44,145	37,557	44,994
TOTAL CURRENT LIAB	183,651	184,438	146,448
DEFERRED CHARGES/INC	109,789	92,293	85,818
LONG TERM DEBT	179,238	154,413	179,346
OTHER LONG TERM LIAB	39,724	37,219	34,980
TOTAL LIABILITIES	512,402	468,363	446,592
PREFERRED STOCK	1,960	1,960	1,960
COMMON STOCK NET	256,785	250,387	19,423
CAPITAL SURPLUS	NA	NA	61,205
RETAINED EARNINGS	NA	NA	184,232
TREASURY STOCK	NA	NA	24,017
SHAREHOLDER EQUITY	258,745	252,347	242,803
TOT LIAB & NET WORTH	771,147	720,710	689,395

ANNUAL INCOME (000$)

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
NET SALES	547,229	602,832	556,456
COST OF GOODS	330,424	372,015	334,603
GROSS PROFIT	216,805	230,817	221,853
SELL GEN & ADMIN EXP	129,902	137,246	129,831
INC BEF DEP & AMORT	86,903	93,571	92,022
DEPRECIATION & AMORT	25,304	25,884	25,009
NON-OPERATING INC	2,496	1,829	2,361
INTEREST EXPENSE	21,270	19,088	17,947
INCOME BEFORE TAX	42,825	50,428	51,427
PROV FOR INC TAXES	14,933	17,962	18,603
NET INC BEF EX ITEMS	27,892	32,466	32,824
NET INCOME	27,892	32,466	32,824
OUTSTANDING SHARES	17,557	NA	17,557

CASH FLOW PROVIDED BY OPERATING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
Net Income (Loss)	27,892	32,466
Depreciation/Amortization	25,403	25,923
Net Incr (Decr) Assets/Liabs	-12,622	-12,305
Other Adjustments, Net	8,216	8,046
Net Cash Prov (Used) by Oper	48,889	54,130

CASH FLOW PROVIDED BY INVESTING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
(Incr) Decr in Prop, Plant	-47,254	-42,842
(Incr) Decr in Securities Inv	-2,569	-2,228
Other Cash Inflow (Outflow)	-2,973	-565
Net Cash Prov (Used) by Inv	-52,796	-45,635

CASH FLOW PROVIDED BY FINANCING ACTIVITY ($000S)

Fiscal Year Ending	09/30/1998	09/30/1997
Issue (Purchase) of Equity	1,832	NA
Issue (Repayment) of Debt	24,500	14,400
Dividends, Other Distribution	-23,215	-22,747
Net Cash Prov (Used) by Finan	3,117	-8,347

Net Change in Cash or Equiv	-790	148
Cash or Equiv at Year Start	4,508	4,360
Cash or Equiv at Year End	3,718	4,508

COMMENTS:
FIVE YEAR SUMMARY NOT GIVEN1997 FINANCIALS RESTATED
PRICING INFORMATION

FOR WEEK ENDING:	07/31/1999
LATEST TRADE DATE:	07/30/1999
OUTSTANDING SHARES (000S):	17,628
VOLUME:	12,800
HIGH (OR ASKED):	23.688
LOW (OR BID):	23.375
CLOSE (OR AVERAGE):	23.438
MARKET VALUE (000S):	413,024

EARNINGS INFORMATION

FOR 12 MONTHS ENDING:	07/1999
EARNINGS PER SHARE:	1.45
PRICE/EARNINGS RATIO:	16.1

	CURRENT	PREVIOUS
INDICATED ANNUAL DIVIDEND:	1.340	
CURRENT DIVIDEND:	0.3350	0.3350
EX-DIVIDEND DATE:	06/09/1999	03/09/1999
RECORD DATE:	06/11/1999	03/11/1999
PAYABLE DATE:	07/01/1999	04/01/1999

I/B/E/S: EARNINGS ESTIMATES

	------EPS EST'S------			# OF	CHG IN MEAN($):	
--PERIOD-	MEAN	HIGH	LOW	ESTS	1MONTH	3MONTH
FY 09/99	1.37	1.42	1.35	3	0.00	0.02
FY 09/00	1.78	1.80	1.75	3	0.00	0.01
QTR 06/99	-0.01	0.01	-0.05	3	0.00	-1.16
QTR 09/99	-0.31	-0.27	-0.35	2	0.00	-0.28

EARNINGS PER SHARE ANNUAL GROWTH RATES

LAST 5 YEARS	-9.3%	FY99/98	-13.6%	QTR 06/99	N+%
NEXT 5 YEARS	2.9%	FY00/99	29.6%	QTR 09/99	N-%

		ESTD F/Y EPS:		
LG LACLEDE GAS				
INDUSTRY CODE: GASUTI	PRICE	09/99	09/00	YIELD
GAS UTILITIES	23.50	1.37	1.78	5.7%

FY09/98 EPS:	1.59	DIVIDEND:	1.34	YIELD:	5.7%
FY09/99 P/E:	17.1	P/E REL S&P:	0.55	P/E REL IND:	0.64
FY09/00 P/E:	13.2	P/E REL S&P:	0.50	P/E REL IND:	0.57

	----FCST EPS GRWTH----			---RELATIVE----	
	LG	IND	S&P 500	LG TO IND	LG TO S&P
FY99 VS FY98	-13.6%	14.2%	16.1%	-96	-84
FY00 VS FY99	29.6%	20.6%	17.1%	144	173
NEXT 5 YEARS	2.9%	11.6%	15.8%	25	18
LAST 5 YEARS	-9.3%	8.1%	16.4%	-80	-59
P/E FY 1998	17.1	26.5	30.9	64	55
P/E FY 1999	13.2	23.3	26.6	57	50

DISTRIBUTION OF EPS ESTS. AS OF 07/30/99

LG EPS FY 09/98 $ 1.59

FY 09/99 - 3 ESTS FY 09/00 - 3 ESTS

MEAN EPS $ 1.37 MEAN EPS $ 1.78

```
      X
      X         X                 X      X X
+---------+---------+---------+ +---------+---------+---------+
$1.30    1.35     1.40   1.1.70    1.75      1.80    1.85
```

X=EST R/L=RAISED/LOWERED PAST MO. N=NEW PAST MO. *=9+ ESTS

KEY ANNUAL FINANCIAL RATIOS

FISCAL YEAR ENDING	09/30/1998	09/30/1997	09/30/1996
QUICK RATIO	0.27	0.28	0.34
CURRENT RATIO	0.74	0.76	0.91
SALES/CASH	147.18	133.72	127.63
SG & A/SALES	0.24	0.23	0.23
RECEIVABLES TURNOVER	11.88	12.58	12.21
RECEIVABLES DAYS SALES	30.30	28.62	29.49
INVENTORIES TURNOVER	7.46	8.04	7.22
INVENTORIES DAYS SALES	48.29	44.79	49.85
NET SALES/WORKING CAPITAL	-11.49	-13.36	-42.59
NET SALES/PLANT & EQUIPMENT	1.12	1.29	1.23
NET SALES/CURRENT ASSETS	4.02	4.33	4.17
NET SALES/TOTAL ASSETS	0.71	0.84	0.81
NET SALES/EMPLOYEES	265,130	288,989	268,560
TOTAL LIAB/TOTAL ASSETS	0.66	0.65	0.65
TOTAL LIAB/INVESTED CAPITAL	1.17	1.15	1.06
TOTAL LIAB/COMMON EQUITY	2.00	1.87	1.85
TIMES INTEREST EARNED	3.01	3.64	3.87
CURRENT DEBT/EQUITY	0.38	0.39	0.25
LONG TERM DEBT/EQUITY	0.69	0.61	0.74
TOTAL DEBT/EQUITY	1.07	1.00	0.98
TOTAL ASSETS/EQUITY	2.98	2.86	2.84
PRETAX INC/NET SALES	0.08	0.08	0.09
PRETAX INC/TOTAL ASSETS	0.06	0.07	0.07
PRETAX INC/INVESTED CAPITAL	0.10	0.12	0.12
PRETAX INC/COMMON EQUITY	0.17	0.20	0.21
NET INCOME/NET SALES	0.05	0.05	0.06
NET INCOME/TOTAL ASSETS	0.04	0.05	0.05
NET INCOME/INVESTED CAPITAL	0.06	0.08	0.08
NET INCOME/COMMON EQUITY	0.11	0.13	0.14

FINANCIAL STATEMENT TEXT:
NA; Assets Statement Full text to be supplied in future update.

NA; Liabilities Statement Full text to be supplied in future update.

NA; Income Statement Full text to be supplied in future update.

NEW JERSEY RESOURCES CORP

AUDITOR CHANGE: NA
AUDITOR: DELOITTE & TOUCHE (SOURCE: 10-K)
AUDITOR'S REPORT: UNQUALIFIED

FIVE YEAR SUMMARY

DATE	SALES (000$)	NET INCOME	EPS
1998	710,342	41,757	NA
1997	696,544	39,924	NA
1996	554,753	37,068	NA
1995	460,179	24,785	NA
1994	501,961	32,995	NA
GROWTH RATE	9.0	6.0	NA

PRELIMINARY EARNINGS DATA

ITEMS	VALUES	PERIOD	NEWS DATE
Basic EPS	1.70	2Q	04/21/1999
Basic EPS	2.55	6M	04/21/1999
Primary EPS	-0.23	4Q	10/29/1997
Primary EPS	2.22	12M	10/29/1997
Fully Diluted EPS	1.69	2Q	04/21/1999
Fully Diluted EPS	2.53	6M	04/21/1999
Net Sales	327,315,000	2Q	04/21/1999
Net Sales	571,905,000	6M	04/21/1999
Operating Profit	35,042,000	2Q	04/21/1999
Operating Profit	55,013,000	6M	04/21/1999
Net Income	30,337,000	2Q	04/21/1999
Net Income	45,489,000	6M	04/21/1999
WtdAvg ComStock(Basic)	17,869,000	2Q	04/21/1999
WtdAvg ComStock(Basic)	17,856,000	6M	04/21/1999
WtdAvg ComStock(Primary)	17,911,000	4Q	10/29/1997
WtdAvg ComStock(Primary)	18,016,000	12M	10/29/1997
WtdAvg ComStock(Fully Diluted)	17,976,000	2Q	04/21/1999
WtdAvg ComStock(Fully Diluted)	17,972,000	6M	04/21/1999

NJ Resources

BALANCE SHEET

ANNUAL ASSETS (000$)

FISCAL YEAR ENDING	09/30/98	09/30/97	09/30/96
CASH	2,476	5,467	10,808
RECEIVABLES	46,898	44,373	33,906
INVENTORIES	56,643	39,597	46,776
OTHER CURRENT ASSETS	55,460	50,920	48,472
TOTAL CURRENT ASSETS	161,477	140,357	139,962
PROP, PLANT & EQUIP	919,811	878,272	856,494
ACCUMULATED DEP	239,814	218,912	201,296
NET PROP & EQUIP	679,997	659,360	655,198
DEFERRED CHARGES	49,493	45,721	51,074
DEPOSITS & OTH ASSET	52,051	33,623	8,953
TOTAL ASSETS	943,018	879,061	855,187

ANNUAL LIABILITIES (000$)

FISCAL YEAR ENDING	09/30/98	09/30/97	09/30/96
NOTES PAYABLE	60,700	48,000	35,000
ACCOUNTS PAYABLE	77,167	86,511	65,821
CUR LONG TERM DEBT	1,957	138	1,501
ACCRUED EXPENSES	7,029	5,781	6,032
OTHER CURRENT LIAB	20,956	20,687	30,911
TOTAL CURRENT LIAB	167,809	161,117	139,265
DEFERRED CHARGES/INC	137,024	127,341	117,758
LONG TERM DEBT	326,741	291,407	303,363
TOTAL LIABILITIES	631,574	579,865	560,386
PREFERRED STOCK	20,640	20,760	20,880
COMMON STOCK NET	45,834	45,385	45,295
CAPITAL SURPLUS	218,030	210,385	209,516
RETAINED EARNINGS	43,742	31,204	20,087
OTHER EQUITIES	-16,802	-8,538	-977
SHAREHOLDER EQUITY	311,444	299,196	294,801
TOT LIAB & NET WORTH	943,018	879,061	855,187

ANNUAL INCOME (000$)

FISCAL YEAR ENDING	09/30/98	09/30/97	09/30/96
NET SALES	710,342	696,544	548,512
COST OF GOODS	483,715	465,552	327,991
GROSS PROFIT	226,627	230,992	220,521
SELL GEN & ADMIN EXP	114,748	122,648	119,021
INC BEF DEP & AMORT	111,879	108,344	101,500
DEPRECIATION & AMORT	27,835	25,797	23,229
NON-OPERATING INC	2,353	566	68
INTEREST EXPENSE	19,633	20,513	21,001
INCOME BEFORE TAX	66,764	62,600	57,338
PROV FOR INC TAXES	23,422	21,085	18,671
MINORITY INT (INC)	1,585	1,591	1,599
NET INC BEF EX ITEMS	41,757	39,924	37,068
NET INCOME	41,757	39,924	37,068
OUTSTANDING SHARES	17,810	NA	18,084

CASH FLOW PROVIDED BY OPERATING ACTIVITY ($000S)

Fiscal Year Ending	09/30/98	09/30/97
Net Income (Loss)	41,757	39,924
Depreciation/Amortization	30,551	26,915
Net Incr (Decr) Assets/Liabs	-48,967	5,485
Other Adjustments, Net	-2,281	-5,148
Net Cash Prov (Used) by Oper	21,060	67,176

CASH FLOW PROVIDED BY INVESTING ACTIVITY ($000S)

Fiscal Year Ending	09/30/98	09/30/97
(Incr) Decr in Prop, Plant	-44,456	-47,033
(Acq) Disp of Subs, Business	15,600	16,118
(Incr) Decr in Securities Inv	-9,500	-1,430
Other Cash Inflow (Outflow)	-3,691	-4,062
Net Cash Prov (Used) by Inv	-42,047	-36,407

CASH FLOW PROVIDED BY FINANCING ACTIVITY ($000S)

Fiscal Year Ending	09/30/98	09/30/97
Issue (Purchase) of Equity	-2,781	-7,217
Incr (Decr) In Borrowing	49,853	-182
Dividends, Other Distribution	-29,076	-28,711
Net Cash Prov (Used) by Finan	17,996	-36,110

Net Change in Cash or Equiv	-2,991	-5,341
Cash or Equiv at Year Start	5,467	10,808
Cash or Equiv at Year End	2,476	5,467

COMMENTS:
FIVE YEAR SUMMARY GIVEN AS STATED1997 FINANCIALS RESTATED

PRICING INFORMATION

FOR WEEK ENDING:	05/31/99
LATEST TRADE DATE:	05/28/99
OUTSTANDING SHARES (000S):	17,916
VOLUME:	27,400
HIGH (OR ASKED):	38.188
LOW (OR BID):	37.125
CLOSE (OR AVERAGE):	37.750
MARKET VALUE (000S):	676,329

EARNINGS INFORMATION

FOR 12 MONTHS ENDING:	05/99
EARNINGS PER SHARE:	2.49
PRICE/EARNINGS RATIO:	15.1

NJ Resources

	CURRENT	PREVIOUS
INDICATED ANNUAL DIVIDEND:	1.680	
CURRENT DIVIDEND:	0.4200	0.4200
EX-DIVIDEND DATE:	03/11/99	12/11/98
RECORD DATE:	03/15/99	12/15/98
PAYABLE DATE:	04/01/99	01/04/99

I/B/E/S: EARNINGS ESTIMATES

	------EPS EST'S------			# OF	CHG IN MEAN($):	
--PERIOD-	MEAN	HIGH	LOW	ESTS	1MONTH	3MONTH
FY 09/99	2.50	2.52	2.50	7	0.00	0.01
FY 09/00	2.66	2.71	2.60	6	0.00	-0.01
QTR 06/99	0.17	0.19	0.15	5	0.00	-1.53
QTR 09/99	-0.20	-0.19	-0.21	4	0.00	-0.36

EARNINGS PER SHARE ANNUAL GROWTH RATES

LAST 5 YEARS	18.3%	FY99/98	7.5%	QTR 06/99	6.3%
NEXT 5 YEARS	6.0%	FY00/99	6.2%	QTR 09/99	N+%

NJR NEW JERSEY RES

		ESTD F/Y EPS:		
INDUSTRY CODE: GASUTI	PRICE	09/99	09/00	YIELD
GAS UTILITIES	37.13	2.50	2.66	4.5%

FY09/98 EPS:	2.33	DIVIDEND:	1.68	YIELD:	4.5%
FY09/99 P/E:	14.8	P/E REL S&P:	0.50	P/E REL IND:	0.61
FY09/00 P/E:	14.0	P/E REL S&P:	0.55	P/E REL IND:	0.63

	----FCST EPS GRWTH----			---RELATIVE----	
	NJR	IND	S&P 500	NJR TO IND	NJR TO S&P
FY99 VS FY98	7.5%	10.3%	16.6%	73	45
FY00 VS FY99	6.2%	18.4%	16.8%	34	37
NEXT 5 YEARS	6.0	11.6%	15.5%	52	39
LAST 5 YEARS	18.3%	6.6%	16.5%	157	118
P/E FY 1998	14.8	24.3	29.8	61	50
P/E FY 1999	14.0	22.0	25.6	63	55

DISTRIBUTION OF EPS ESTS. AS OF 05/28/99

NJR EPS FY 09/98 $ 2.33

FY 09/99 - 7 ESTS   FY 09/00 - 6 ESTS

MEAN EPS $ 2.50   MEAN EPS $ 2.66

```
                      X
                      X
                      X                                  X
                      X                                  X     X
                      XX X                           X   X     X
+---------+---------+---------+  +---------+---------+---------+
$2.40     2.45      2.50     2.2.50      2.60      2.70      2.80
```

X=EST R/L=RAISED/LOWERED PAST MO. N=NEW PAST MO. *=9+ ESTS

NJ Resources KEY ANNUAL FINANCIAL RATIOS

FISCAL YEAR ENDING	09/30/98	09/30/97	09/30/96
QUICK RATIO	0.29	0.31	0.32
CURRENT RATIO	0.96	0.87	1.01
SALES/CASH	286.89	127.41	50.75
SG & A/SALES	0.16	0.18	0.22
RECEIVABLES TURNOVER	15.15	15.70	16.18
RECEIVABLES DAYS SALES	23.77	22.93	22.25
INVENTORIES TURNOVER	12.54	17.59	11.73
INVENTORIES DAYS SALES	28.71	20.47	30.70
NET SALES/WORKING CAPITAL	-999.99	-33.55	786.96
NET SALES/PLANT & EQUIPMENT	1.04	1.06	0.84
NET SALES/CURRENT ASSETS	4.40	4.96	3.92
NET SALES/TOTAL ASSETS	0.75	0.79	0.64
NET SALES/EMPLOYEES	898030	845320	640785
TOTAL LIAB/TOTAL ASSETS	0.67	0.66	0.66
TOTAL LIAB/INVESTED CAPITAL	0.99	0.98	0.94
TOTAL LIAB/COMMON EQUITY	2.17	2.08	2.05
TIMES INTEREST EARNED	4.40	4.05	3.73
CURRENT DEBT/EQUITY	0.01	0.00	0.01
LONG TERM DEBT/EQUITY	1.05	0.97	1.03
TOTAL DEBT/EQUITY	1.06	0.97	1.03
TOTAL ASSETS/EQUITY	3.03	2.94	2.90
PRETAX INC/NET SALES	0.09	0.09	0.10
PRETAX INC/TOTAL ASSETS	0.07	0.07	0.07
PRETAX INC/INVESTED CAPITAL	0.10	0.11	0.10
PRETAX INC/COMMON EQUITY	0.23	0.22	0.21
NET INCOME/NET SALES	0.06	0.06	0.07
NET INCOME/TOTAL ASSETS	0.04	0.05	0.04
NET INCOME/INVESTED CAPITAL	0.07	0.07	0.06
NET INCOME/COMMON EQUITY	0.14	0.14	0.14

FINANCIAL STATEMENT TEXT:
NA; Assets Statement Full text to be supplied in future update.

NA; Liabilities Statement Full text to be supplied in future update.

NA; Income Statement Full text to be supplied in future update.

PIEDMONT NATURAL GAS CO INC

AUDITOR CHANGE: NA
AUDITOR: DELOITTE & TOUCHE (SOURCE: 10-K)
AUDITOR'S REPORT: UNQUALIFIED

FIVE YEAR SUMMARY

DATE	SALES (000$)	NET INCOME	EPS
1998	765,277	60,313	1.98
1997	775,517	54,074	1.81
1996	685,055	48,562	1.67
1995	505,223	40,310	1.45
1994	575,354	35,506	1.35
GROWTH RATE	7.3	14.1	10.0

BALANCE SHEET

ANNUAL ASSETS (000$)

FISCAL YEAR ENDING	10/31/1998	10/31/1997	10/31/1996
CASH	37,204	26,595	25,475
RECEIVABLES	24,459	32,367	32,378
INVENTORIES	48,138	54,457	57,516
OTHER CURRENT ASSETS	32,741	18,737	42,618
TOTAL CURRENT ASSETS	142,542	132,156	157,987
PROP, PLANT & EQUIP	990,640	941,736	889,101
NET PROP & EQUIP	990,640	941,736	889,101
DEFERRED CHARGES	2,455	2,759	3,033
DEPOSITS & OTH ASSET	27,207	21,505	16,965
TOTAL ASSETS	1,162,844	1,098,156	1,067,086

ANNUAL LIABILITIES (000$)

FISCAL YEAR ENDING	10/31/1998	10/31/1997	10/31/1996
NOTES PAYABLE	32,000	25,000	39,000
ACCOUNTS PAYABLE	67,296	65,103	60,150
CUR LONG TERM DEBT	10,000	10,000	10,000
ACCRUED EXPENSES	12,893	11,041	9,940
INCOME TAXES	15,367	10,276	17,727
OTHER CURRENT LIAB	48,292	34,109	16,838
TOTAL CURRENT LIAB	185,848	155,529	153,655
DEFERRED CHARGES/INC	118,674	113,630	136,340
LONG TERM DEBT	371,000	381,000	391,000
OTHER LONG TERM LIAB	29,054	28,171	NA
TOTAL LIABILITIES	704,576	678,330	680,995
COMMON STOCK NET	279,709	262,576	246,907
RETAINED EARNINGS	178,559	157,250	139,184
SHAREHOLDER EQUITY	458,268	419,826	386,091
TOT LIAB & NET WORTH	1,162,844	1,098,156	1,067,086

ANNUAL INCOME (000$)

FISCAL YEAR ENDING	10/31/1998	10/31/1997	10/31/1996
NET SALES	765,277	775,517	685,055
COST OF GOODS	457,130	476,825	409,909
GROSS PROFIT	308,147	298,692	275,146
SELL GEN & ADMIN EXP	137,566	143,571	136,869
INC BEF DEP & AMORT	170,581	155,121	138,277
DEPRECIATION & AMORT	42,175	39,187	36,039
NON-OPERATING INC	2,343	4,084	5,000
INTEREST EXPENSE	33,187	33,996	31,067
INCOME BEFORE TAX	97,562	86,022	76,171
PROV FOR INC TAXES	37,249	31,948	27,609
NET INC BEF EX ITEMS	60,313	54,074	48,562
NET INCOME	60,313	54,074	48,562
OUTSTANDING SHARES	30,737	30,193	29,548

CASH FLOW PROVIDED BY OPERATING ACTIVITY ($000S)

Fiscal Year Ending	10/31/1998	10/31/1997
Net Income (Loss)	60,313	54,074
Depreciation/Amortization	45,555	42,883
Net Incr (Decr) Assets/Liabs	9,438	39,933
Other Adjustments, Net	8,082	2,565
Net Cash Prov (Used) by Oper	123,388	139,455

CASH FLOW PROVIDED BY INVESTING ACTIVITY ($000S)

Fiscal Year Ending	10/31/1998	10/31/1997
(Incr) Decr in Prop, Plant	-90,898	-92,057
Other Cash Inflow (Outflow)	-1,112	-1,594
Net Cash Prov (Used) by Inv	-92,010	-93,651

CASH FLOW PROVIDED BY FINANCING ACTIVITY ($000S)

Fiscal Year Ending	10/31/1998	10/31/1997
Issue (Purchase) of Equity	15,136	14,420
Issue (Repayment) of Debt	-10,000	-10,000
Incr (Decr) In Borrowing	7,000	-14,000
Dividends, Other Distribution	-39,004	-36,008
Net Cash Prov (Used) by Finan	-26,868	-45,588

Net Change in Cash or Equiv	4,510	216
Cash or Equiv at Year Start	5,210	4,994
Cash or Equiv at Year End	9,720	5,210

COMMENTS:
NA

PRICING INFORMATION

FOR WEEK ENDING:	07/31/1999
LATEST TRADE DATE:	07/30/1999
OUTSTANDING SHARES (000S):	31,053
VOLUME:	43,600
HIGH (OR ASKED):	34.125
LOW (OR BID):	33.875
CLOSE (OR AVERAGE):	34.063
MARKET VALUE (000S):	1,057,665

EARNINGS INFORMATION

FOR 12 MONTHS ENDING:	07/1999
EARNINGS PER SHARE:	1.88
PRICE/EARNINGS RATIO:	18.1

	CURRENT	PREVIOUS
INDICATED ANNUAL DIVIDEND:	1.380	
CURRENT DIVIDEND:	0.3450	0.3450
EX-DIVIDEND DATE:	06/22/1999	03/23/1999
RECORD DATE:	06/24/1999	03/25/1999
PAYABLE DATE:	07/15/1999	04/15/1999

I/B/E/S: EARNINGS ESTIMATES

	------EPS EST'S------			# OF	CHG IN MEAN($):	
--PERIOD-	MEAN	HIGH	LOW	ESTS	1MONTH	3MONTH
FY 10/99	1.91	1.94	1.88	7	0.00	-0.16
FY 10/00	2.17	2.25	2.10	4	0.00	-0.05
QTR 07/99	-0.22	-0.19	-0.25	5	0.00	-1.46
QTR 10/99	-0.30	-0.27	-0.31	4	0.00	-0.08

EARNINGS PER SHARE ANNUAL GROWTH RATES

LAST 5 YEARS	6.1%	FY99/98	-3.7%	QTR 07/99	N-%
NEXT 5 YEARS	6.1%	FY00/99	13.7%	QTR 10/99	N+%

PNY PIEDMONT NAT GAS		ESTD F/Y EPS:		
INDUSTRY CODE: GASUTI	PRICE	10/99	10/00	YIELD
GAS UTILITIES	34.13	1.91	2.17	4.0%

FY10/98 EPS:	1.98	DIVIDEND:	1.38	YIELD:	4.0%
FY10/99 P/E:	17.9	P/E REL S&P:	0.58	P/E REL IND:	0.67
FY10/00 P/E:	15.7	P/E REL S&P:	0.59	P/E REL IND:	0.68

	----FCST EPS GRWTH----			---RELATIVE----	
	PNY	IND	S&P 500	PNY TO IND	PNY TO S&P
FY99 VS FY98	-3.7%	14.2%	16.1%	-26	-23
FY00 VS FY99	13.7%	20.6%	17.1%	66	80
NEXT 5 YEARS	6.1%	11.6%	15.8%	53	39
LAST 5 YEARS	6.1%	8.1%	16.4%	53	39
P/E FY 1998	17.9	26.5	30.9	67	58
P/E FY 1999	15.7	23.3	26.6	68	59

DISTRIBUTION OF EPS ESTS. AS OF 07/30/99

PNY EPS FY 10/98 $ 1.98

FY 10/99 - 7 ESTS FY 10/00 - 4 ESTS

MEAN EPS $ 1.91 MEAN EPS $ 2.17

```
          X
          X
          X
      X   X     X X                        X    X X      X
  +---------+---------+---------+  +---------+---------+---------+
 $1.85     1.90      1.95    2.2.00     2.10      2.20    2.30
```

X=EST R/L=RAISED/LOWERED PAST MO. N=NEW PAST MO. *=9+ ESTS

KEY ANNUAL FINANCIAL RATIOS

FISCAL YEAR ENDING	10/31/1998	10/31/1997	10/31/1996
QUICK RATIO	0.33	0.38	0.38
CURRENT RATIO	0.77	0.85	1.03
SALES/CASH	20.57	29.16	26.89
SG & A/SALES	0.18	0.19	0.20
RECEIVABLES TURNOVER	31.29	23.96	21.16
RECEIVABLES DAYS SALES	11.51	15.02	17.01
INVENTORIES TURNOVER	15.90	14.24	11.91
INVENTORIES DAYS SALES	22.64	25.28	30.22
NET SALES/WORKING CAPITAL	-17.67	-33.18	158.14
NET SALES/PLANT & EQUIPMENT	0.77	0.82	0.77
NET SALES/CURRENT ASSETS	5.37	5.87	4.34
NET SALES/TOTAL ASSETS	0.66	0.71	0.64
NET SALES/EMPLOYEES	415,685	407,309	347,215
TOTAL LIAB/TOTAL ASSETS	0.61	0.62	0.64
TOTAL LIAB/INVESTED CAPITAL	0.85	0.85	0.88
TOTAL LIAB/COMMON EQUITY	1.54	1.62	1.76
TIMES INTEREST EARNED	3.94	3.53	3.45
CURRENT DEBT/EQUITY	0.02	0.02	0.03
LONG TERM DEBT/EQUITY	0.81	0.91	1.01
TOTAL DEBT/EQUITY	0.83	0.93	1.04
TOTAL ASSETS/EQUITY	2.54	2.62	2.76
PRETAX INC/NET SALES	0.13	0.11	0.11
PRETAX INC/TOTAL ASSETS	0.08	0.08	0.07
PRETAX INC/INVESTED CAPITAL	0.12	0.11	0.10
PRETAX INC/COMMON EQUITY	0.21	0.20	0.20
NET INCOME/NET SALES	0.08	0.07	0.07
NET INCOME/TOTAL ASSETS	0.05	0.05	0.05
NET INCOME/INVESTED CAPITAL	0.07	0.07	0.06
NET INCOME/COMMON EQUITY	0.13	0.13	0.13

FINANCIAL STATEMENT TEXT:

NA; Assets Statement Full text to be supplied in future update.

NA; Liabilities Statement Full text to be supplied in future update.

NA; Income Statement Full text to be supplied in future update.

Prices of gas utility shares, which are income stocks, have traditionally moved inversely to changes in interest rates. Money rates have risen moderately in recent months, but gas stocks, by and large, have lost little support. Since this utility group hasn't been building earning power fast enough to step up its dividend-paying potential, we suspect that a measure of merger speculation, spurred by deregulation programs, is giving many of these equities an added underpinning. Still, gas stocks continue to sell on a yield basis, keeping them attractive for income.

INDUSTRY TIMELINESS: 88 (of 94)

The New Business Arena

Back in the Eighties, energy policymakers, responding to supply/demand imbalances in the natural gas market, began to rework the operating structure of the interstate pipelines and the local distributors. The makeover altogether changed the long-established business relationship between the two industry subsegments and between them and the gas producers. The new regulatory guidelines ended the pipelines' traditional calling as the purveyors of gas supply for local utilities. The former became common carriers for buyers and sellers, compelling the utilities to be fully self-reliant in negotiating the best supply deals.

The new ground rules have also encouraged competition, moving pipelines to scramble for market share and forcing local gas distributors to defend their turf against sellers of other fuels and electricity and to block incursions by the long-haul gas systems. The industry has adapted to its makeover, gaining a keener sense of business and contributing to a more efficient gas market.

During the Nineties, regulators took their reinvention efforts a step further and established an even more competitive market to the benefit of end-users. Unbundling became the industry byword, with both interstate and local gas systems being required to segregate the components of the traditional utility service and offer to sell them separately or in package plans. Thus, high-volume industrial users have been able to arrange for gas-supply transport and/or storage service with a utility or pipeline of its choosing.

The unbundling program has lately been extended to residential and commercial customers, which, under various pilot and state-wide programs, may sign up with the gas supplier of their choice and call upon any available contractor for repair work or fuel-management service. Profits of the newly segregated businesses aren't regulated, though a utility affiliate, say, doing repairs and maintenance, might come under some measure of state rate control to let smaller independent contractors gain a price advantage.

No Earnings Windfall Yet

Competition is the trade-off and has been the economic regulator of prices and profits. Deregulation has, in effect, created a rugged playing field for utility subsidiaries and their affiliates in joint ventures. There are ample business opportunities, but with many contenders having entered the fray, there has been little room for profit. As marginal players abandon the field, the economics of the business might improve.

As it stands now, save for those companies that have long been heavily invested in exploration, regulated utility service still accounts for some 95% of assets and earnings, with allowed returns on equity at 11.0%-11.5%—not enough to invite steeply rising values for these stocks. And alternate fuels competition may deter utilities from seeking higher returns.

Investment Guide

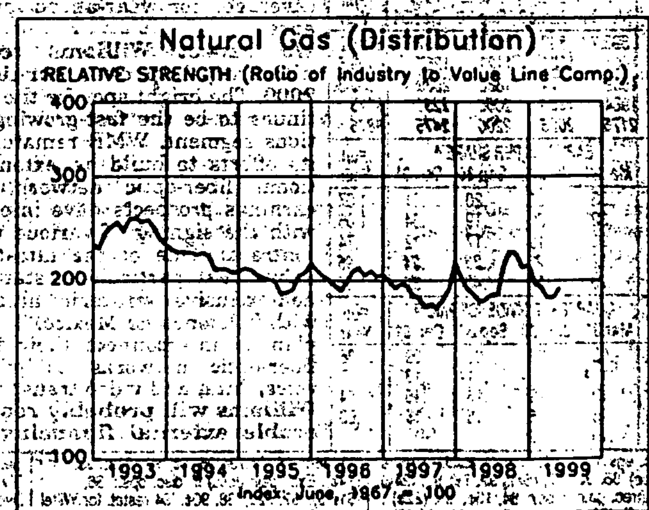
The opportunity to establish energy-related businesses in a free market has stirred both gas and electric companies to buy up kindred utilities to gain regional dominance in the fuel and power market and to extend their base of captive customers for marketing associated services. While it might be difficult to enhance share earnings via the acquisition of a regulated business, under the circumstances, any gas company today seems to be a buyout target. Thus, it appears that gas stocks have been bid on merger speculation.

Still, gas stocks remain income vehicles because dividends are the chief incentive for investing in a regulated utility. The recent climb in money rates may have capped the rise in the group's market values, serving as an equalizer to the effect of merger speculation. But the current yield averages 4.6%, based on a rising annual payout of 1%-2%, which should provide a respectable one-year total return in today's market. Conservative investors ought to favor the higher-quality issues, which should trace narrower price swings than the rest of this untimely stock group.

Gerald Holtzman

Composite Statistics: Natural Gas (Distribution)

1995	1996	1997	1998	1999	2000		02-04
15307	18028	20877	20830	21950	23100	Revenues ($mill)	27500
884.0	1101.5	1225.9	905.7	1150	1340	Net Profit ($mill)	1650
34.5%	34.7%	34.5%	36.7%	35.0%	35.0%	Income Tax Rate	36.0%
5.8%	6.8%	5.9%	4.4%	5.5%	5.8%	Net Profit Margin	6.0%
49.8%	48.4%	48.7%	43.7%	44.0%	44.5%	Long-Term Debt Ratio	45.0%
48.3%	49.0%	49.1%	48.8%	48.5%	48.5%	Common Equity Ratio	49.0%
16558	17615	19634	24360	25500	26100	Total Capital ($mill)	30850
18158	19586	21265	24563	25880	26450	Net Plant ($mill)	31250
7.2%	8.0%	7.9%	5.3%	6.0%	6.5%	Return on Total Cap'l	7.0%
10.7%	12.1%	11.7%	6.6%	8.0%	8.5%	Return on Shr. Equity	8.5%
10.9%	12.4%	12.2%	6.8%	8.5%	10.0%	Return on Com Equity	10.5%
2.1%	4.1%	4.2%	NMF	1.0%	2.0%	Retained to Com Eq	3.5%
81%	68%	67%	114%	91%	80%	All Div'ds to Net Prof	68%
14.3	13.7	14.8	26.9	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	13.5
.96	.88	.85	1.41			Relative P/E Ratio	.90
5.6%	4.9%	4.4%	4.3%			Avg Ann'l Div'd Yield	4.9%
266%	289%	289%	212%	220%	225%	Fixed Charge Coverage	250%



THE VALUE LINE® Investment Survey®

Part 1 Summary & Index

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

August 27, 1999

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

16.7

26 Weeks Ago	Market Low 10-28-87	Market High 4-22-98
16.2	10.6	19.7

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

1.9%

26 Weeks Ago	Market Low 10-28-87	Market High 4-22-98
2.1%	3.7%	1.6%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

65%

26 Weeks Ago	Market Low 10-28-87	Market High 4-22-98
60%	120%	35%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*Reviewed in this week's edition.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LIV, No. 51.

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Federal Reserve Statistical Release

H.15

Selected Interest Rates

Release Date: June 18, 1999

H.15: Release | Release dates | About | ASCII | Historical data | Daily update

H.15 Daily Update

The weekly release is posted on Monday. Daily updates of the weekly release are posted Tuesday through Friday on this site.

H.15 DAILY UPDATE: WEB RELEASE ONLY
SELECTED INTEREST RATES

For immediate release
June 18, 1999

Yields in percent per annum

Instruments	Mon Jun 14	Tue Jun 15	Wed Jun 16	Thu Jun 17
SELECTED INTEREST RATES				
Federal funds (effective) 1 2 3	4.74	4.67	4.71	4.73
Commercial paper 3 4 5 6				
Nonfinancial				
1-month	4.93	4.94	4.97	4.96
2-month	4.95	5.01	5.01	4.98
3-month	5.00	5.00	5.01	4.99
Financial				
1-month	4.95	4.98	4.98	4.96
2-month	4.99	5.01	5.01	5.03
3-month	5.00	5.03	5.05	5.07
Bankers acceptances (top rated) 3 4 7				
3-month	5.06	5.06	5.06	4.95
6-month	5.18	5.18	5.18	5.05
CDs (secondary market)				

Federal Reserve Statistical Release

H.15

Selected Interest Rates

Release Date: July 2, 1999

H.15: Release | Release dates | About | ASCII | Historical data | Daily update

H.15 Daily Update

The weekly release is posted on Monday. Daily updates of the weekly release are posted Tuesday through Friday on this site.

H.15 DAILY UPDATE: WEB RELEASE ONLY
SELECTED INTEREST RATES

For immediate release
July 2, 1999

Yields in percent per annum

	Mon Jun 28	Tue Jun 29	Wed Jun 30	Thu Jul 1
Instruments				
SELECTED INTEREST RATES				
Federal funds (effective) 1 2 3	5.04	4.91	5.12	5.76
Commercial paper 3 4 5 6				
Nonfinancial				
1-month	5.17	5.18	5.13	5.08
2-month	5.12	5.13	5.16	5.10
3-month	5.13	5.12	5.17	5.11
Financial				
1-month	5.14	5.16	5.15	5.09
2-month	5.16	5.17	5.16	5.12
3-month	5.22	5.19	5.19	5.13
Bankers acceptances (top rated) 3 4 7				
3-month	5.18	5.22	5.24	5.24
6-month	5.26	5.28	5.42	5.42
CDs (secondary market)				
1-month	5.20	5.21	5.22	5.13
3-month	5.30	5.32	5.32	5.22
6-month	5.42	5.43	5.63	5.51
Eurodollar deposits (London) 3 9				
1-month	5.13	5.13	5.13	5.06
3-month	5.25	5.25	5.25	5.19
6-month	5.38	5.50	5.56	5.50
Bank prime loan 2 3 10	7.75	7.75	7.75	8.00
Discount window borrowing 2 11	4.50	4.50	4.50	4.50
U.S. Government securities				
Treasury bills				
Auction high 3 4 12				
3-month	4.75			
6-month	4.96			
1-year				
Secondary market 3 4				
3-month	4.68	4.70	4.65	4.55
6-month	4.89	4.92	4.84	4.81

DESCRIPTION OF THE TREASURY CONSTANT MATURITY SERIES

Yields on Treasury securities at "constant maturity" are interpolated by the U.S. Treasury from the daily yield curve. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 3 and 6 months and 1, 2, 3, 5, 7, 10, 20, and 30 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. In estimating the 20-year constant maturity, the Treasury incorporates the prevailing market yield on an outstanding Treasury bond with approximately 20 years remaining to maturity.

H.15: Release | Release dates | About | ASCII | Historical data | Daily update

Home | Statistical releases

Last update: July 2, 1999, 4:00 pm

THE VALUE LINE Investment Survey®

PAGES 5535-5550
File in page order in the *Selection & Opinion* binder.

PART 2 — *Selection & Opinion* — MAY 28, 1999

The Quarterly Economic View

In This Issue

In Three Parts: Part 1 is the Summary & Index. This is Part 2, Selection & Opinion. Part 3 is Ratings & Reports. Volume LIV, Number 38.

Published weekly by VALUE LINE PUBLISHING, INC.
220 East 42nd Street, New York, NY 10017-5891.

ECONOMIC AND STOCK MARKET COMMENTARY

The U.S. economy continues to move ahead briskly as we proceed through the second quarter, with this strength being underscored by steady improvement in employment, retail sales, industrial production, and factory usage. In fact, except for a widening global trade deficit (weak consumer spending abroad is putting a lid on demand for American goods and services), we see little evidence of any deterioration in the economy, in spite of the fact that the business expansion is now in its ninth year. Moreover, we look for no more than a modest deceleration in growth in the current quarter, with GDP increasing by a still-healthy 3%, or so.

Several key trends account for this strong economic performance. For starters, considerable wealth is being created by the long bull market, as well as by rising income levels and increasing home values. Such wealth, along with modest gains in employment, has given the American public the wherewithal to continue spending freely. Healthy consumer demand, in turn, is giving domestic industrial concerns the incentive to increase their productive capacity. This is helping to boost output at U.S. factories, raise spending on plant and equipment, and necessitate the hiring of additional workers. New spending power and wealth are thus created.

Importantly, this strong economic uptrend is being accompanied, for the most part, by low inflation. Rising productivity (or the output per hour of work), which continues to be fostered by the growing use of labor-saving technologies, has been one of the keys to this nation's low inflation rate for much of this decade. Increased global competition and plentiful and inexpensive sources of raw materials (in particular, energy) have also been instrumental in helping to keep costs down. At the same time, interest rates have trended lower for much of this period. Low rates, too, have helped to sustain the business uptrend, by keeping housing costs under control and by reducing the costs of business expansion. Modest inflation, together with steady economic growth, has given the Federal Reserve the leeway to retain an accommodative monetary stance over the past several years.

Continued on page 5538

VALUE LINE'S FORECAST FOR THE U.S. ECONOMY

Statistical Summary for 1998-2000

	98:4	99:1	99:2	99:3	99:4	2000:1	2000:2	2000:3	1999	2000
GDP AND OTHER KEY MEASURES										
Real Gross Domestic Product (1992 Chained $Bill.)	7678	7763	7821	7871	7916	7951	7998	8048	7843	8024
Unit Car Sales (Million Units)	8.5	8.0	8.2	8.1	8.0	7.8	7.8	7.8	8.1	7.8
Housing Starts (Million Units)	1.70	1.79	1.60	1.55	1.55	1.53	1.53	1.55	1.63	1.55
Pretax Corporate Profits ($Bill.)	708.1	729.5	774.0	759.0	752.0	751.0	805.0	797.0	760.0	798.0
ANNUALIZED RATES OF CHANGE										
Gross Domestic Product (Real)	6.0	4.5	3.0	2.6	2.3	1.8	2.4	2.5	3.8	2.3
GDP Price Index	0.8	1.4	2.5	2.2	2.0	2.0	2.0	2.2	2.0	2.1
CPI-All Urban Consumers	1.7	1.5	4.8	2.5	2.3	2.3	2.4	2.5	2.8	2.5
AVERAGE FOR THE PERIOD										
National Unemployment Rate	4.4	4.3	4.3	4.3	4.3	4.4	4.4	4.5	4.3	4.4
Prime Rate	7.9	7.8	7.8	7.8	8.0	8.0	8.0	8.0	7.8	8.0
30-Year Treasury Bond Rate	5.1	5.4	5.7	5.7	5.6	5.6	5.6	5.7	5.6	5.6

Value Line Forecast for the U.S. Economy

	ACTUAL	ESTIMATED						
	98:4	99:1	99:2	99:3	99:4	2000:1	2000:2	2000:3
GROSS DOMESTIC PRODUCT AND ITS COMPONENTS (1992 CHAIN WEIGHTED $) BILLIONS OF DOLLARS								
Total Consumption	5246	*5332*	*5372*	*5409*	*5448*	*5488*	*5531*	*5575*
Nonresidential Fixed Investment	992	*1010*	*1034*	*1057*	*1072*	*1086*	*1101*	*1118*
Residential Fixed Investment	324	*336*	*335*	*333*	*331*	*327*	*324*	*322*
Exports	1010	*989*	*1002*	*1005*	*1017*	*1033*	*1048*	*1064*
Imports	1260	*1295*	*1313*	*1348*	*1381*	*1392*	*1402*	*1413*
Federal Government	461	*460*	*464*	*465*	*467*	*469*	*470*	*471*
State & Local Governments	850	*865*	*868*	*873*	*881*	*887*	*894*	*901*
Gross Domestic Product	8681	*8808*	*8889*	*8976*	*9057*	*9133*	*9216*	*9307*
Real GDP (1992 Chain Weighted $)	7678	*7763*	*7821*	*7871*	*7916*	*7951*	*7998*	*8048*
PRICES AND WAGES-ANNUAL RATES OF CHANGE								
GDP Price Index (1992 Chain Weighted)	0.8	*1.4*	*2.5*	*2.2*	*2.0*	*2.0*	*2.0*	*2.2*
CPI-All Urban Consumers	1.7	*1.5*	*4.8*	*2.5*	*2.3*	*2.3*	*2.4*	*2.5*
PPI-Finished Goods	1.2	*1.9*	*3.8*	*2.0*	*1.5*	*1.5*	*1.6*	*1.7*
Employment Cost Index—Total Comp.	2.9	*1.4*	*4.0*	*3.8*	*3.7*	*3.5*	*3.5*	*3.6*
Output per Hour-Nonfarm	4.6	*3.0*	*3.0*	*2.0*	*1.5*	*1.5*	*1.5*	*1.8*
PRODUCTION AND OTHER KEY MEASURES								
Industrial Prod. (% Change, Annualized)	2.2	*0.7*	*3.0*	*3.0*	*2.5*	*2.0*	*2.3*	*2.5*
Capacity Utilization Rate (%)	80.1	*79.5*	*80.5*	*80.5*	*80.5*	*80.0*	*80.2*	*80.3*
Housing Starts (Mill. Units)	1.70	*1.79*	*1.60*	*1.55*	*1.55*	*1.53*	*1.53*	*1.55*
Total Light Vehicle Sales (Mill. Units)	16.4	*16.0*	*16.0*	*15.6*	*15.6*	*15.5*	*15.4*	*15.4*
Unit Car Sales (Mill. Units)	8.5	*8.0*	*8.2*	*8.1*	*8.0*	*7.8*	*7.8*	*7.8*
ollar Exchange Rate (% Change)	-21.0	*1.9*	*7.9*	*2.9*	*-0.2*	*-6.1*	*-1.5*	*-1.5*
al Unemployment Rate (%)	4.4	*4.3*	*4.3*	*4.3*	*4.3*	*4.4*	*4.4*	*4.5*
Federal Budget Surplus (Unified, FY, $Bill)	-55.0	*5.1*	*136.0*	*30.0*	*35.0*	*15.0*	*60.0*	*-2.0*
Price of Oil ($Bbl., U.S. Refiners' Cost)	11.67	*11.46*	*16.15*	*15.90*	*16.20*	*16.45*	*16.55*	*16.65*
MONEY AND INTEREST RATES								
Annual Money Supply (M2)	4365	*4443*	*4500*	*4556*	*4609*	*4661*	*4714*	*4766*
Yr-to-Yr % Change	8.5	*8.4*	*7.8*	*7.3*	*5.6*	*4.9*	*4.8*	*4.6*
3-Month Treasury Bill Rate (%)	4.3	*4.4*	*4.7*	*4.7*	*4.7*	*4.8*	*4.8*	*4.8*
Federal Funds Rate (%)	4.9	*4.7*	*4.8*	*4.8*	*4.9*	*5.0*	*5.0*	*5.0*
30-Year Treasury Bond Rate (%)	5.1	*5.4*	*5.7*	*5.7*	*5.6*	*5.6*	*5.6*	*5.7*
AAA Corporate Bond Rate (%)	6.3	*6.4*	*6.2*	*6.2*	*6.2*	*6.1*	*6.1*	*6.2*
Prime Rate (%)	7.9	*7.8*	*7.8*	*7.8*	*8.0*	*8.0*	*8.0*	*8.0*
INCOMES								
Personal Income (Annualized % Change)	5.5	*5.4*	*4.8*	*4.7*	*4.5*	*4.4*	*4.5*	*4.7*
Real Disp. Inc. (Annualized % Change)	4.3	*4.6*	*3.0*	*3.0*	*3.0*	*3.0*	*3.5*	*3.5*
Personal Savings Rate (%)	0.0	*-0.5*	*-0.5*	*-0.3*	*-0.3*	*0.1*	*0.2*	*0.5*
Pretax Corporate Profits (Annualized $Bill)	708.1	*729.5*	*774.0*	*759.0*	*752.0*	*751.0*	*805.0*	*797.0*
Aftertax Corporate Profits (Annualized $Bill)	472.5	*485.9*	*511.0*	*501.0*	*496.0*	*496.0*	*531.0*	*526.0*
Yr-to-Yr % Change	-3.0	*1.4*	*6.0*	*5.0*	*5.0*	*2.0*	*4.0*	*5.0*
COMPOSITION OF REAL GDP-ANNUAL RATES OF CHANGE								
Gross Domestic Product	6.0	*4.5*	*3.0*	*2.6*	*2.3*	*1.8*	*2.4*	*2.5*
Final Sales	6.6	*4.5*	*3.0*	*2.0*	*2.0*	*2.3*	*2.5*	*2.5*
Total Consumption	5.0	*6.7*	*3.0*	*2.8*	*2.9*	*3.0*	*3.2*	*3.2*
Nonresidential Fixed Investment	14.6	*7.6*	*10.0*	*9.0*	*6.0*	*5.0*	*6.0*	*6.0*
Construction	6.0	*-0.1*	*-5.0*	*5.0*	*1.0*	*2.0*	*3.0*	*3.0*
Durable Equipment	17.8	*10.5*	*16.0*	*12.0*	*9.0*	*6.0*	*7.0*	*7.0*
Residential Fixed Investment	10.0	*15.6*	*-1.0*	*-2.0*	*-3.0*	*-5.0*	*-3.0*	*-3.0*
Exports	19.7	*-7.7*	*5.4*	*1.0*	*4.9*	*6.7*	*6.0*	*6.0*
ts	12.0	*11.7*	*5.7*	*11.2*	*9.9*	*3.3*	*3.0*	*3.0*
l Government	7.3	*-0.7*	*3.6*	*1.1*	*1.1*	*1.9*	*1.0*	*1.0*
& Local Governments	1.3	*7.3*	*1.2*	*2.6*	*3.5*	*3.1*	*3.0*	*3.0*

Value Line Forecast for the U.S. Economy

	ACTUAL					ESTIMATED				
	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
GROSS DOMESTIC PRODUCT AND ITS COMPONENTS (1992 CHAIN WEIGHTED $) BILLIONS OF DOLLARS										
Total Consumption	4486	4606	4752	4914	5153	*5390*	*5554*	*5720*	*5892*	*6069*
Nonresidential Fixed Investment	648	711	777	859	961	*1043*	*1110*	*1165*	*1229*	*1303*
Residential Fixed Investment	267	257	276	283	312	*334*	*323*	*320*	*323*	*330*
Exports	712	793	860	970	985	*1003*	*1057*	*1138*	*1228*	*1325*
Imports	817	889	971	1106	1223	*1334*	*1407*	*1467*	*1546*	*1662*
Federal Government	487	471	466	458	453	*464*	*471*	*463*	*458*	*456*
State & Local Governments	766	784	803	827	844	*872*	*897*	*919*	*942*	*964*
Gross Domestic Product	6947	7270	7662	8111	8511	*8932*	*9265*	*9663*	*10111*	*10605*
Real GDP (1992 Chain Weighted $)	6611	6762	6995	7270	7552	*7843*	*8024*	*8225*	*8447*	*8684*
PRICES AND WAGES-ANNUAL RATES OF CHANGE										
GDP Price Index (1992 Chain Weighted)	2.3	2.5	2.1	1.9	1.0	*2.0*	*2.1*	*2.1*	*2.2*	*2.3*
CPI-All Urban Consumers	2.6	2.8	2.9	2.3	1.6	*2.8*	*2.5*	*2.5*	*2.6*	*2.7*
PPI-Finished Goods	0.6	1.9	2.6	0.4	-0.9	*2.3*	*1.6*	*1.6*	*1.8*	*2.0*
Employment Cost Index—Total Comp.	3.2	2.8	2.8	3.1	3.5	*3.5*	*3.5*	*3.5*	*3.5*	*3.5*
Output per Hour-Nonfarm	0.5	0.6	0.8	1.2	2.2	*2.3*	*1.5*	*1.6*	*1.7*	*1.7*
PRODUCTION AND OTHER KEY MEASURES										
Industrial Prod. (% Change)	5.8	3.3	2.8	6.0	3.7	*2.3*	*2.5*	*3.0*	*3.0*	*3.0*
Capacity Utilization Rate (%)	83.1	83.1	82.1	82.0	80.8	*80.3*	*80.2*	*80.7*	*81.3*	*82.0*
Housing Starts (Mill. Units)	1.45	1.36	1.47	1.48	1.62	*1.63*	*1.55*	*1.50*	*1.50*	*1.50*
Total Light Vehicle Sales (Mill. Units)	15.0	14.8	15.1	15.1	15.6	*15.8*	*15.4*	*15.4*	*15.6*	*15.8*
Unit Car Sales (Mill. Units)	9.0	8.6	8.5	8.2	8.2	*8.1*	*7.8*	*7.7*	*7.6*	*7.6*
U.S. Dollar Exchange Rate (% Change)	-1.5	-5.7	4.9	8.0	5.0	*-1.0*	*-2.2*	*-3.3*	*-2.6*	*-1.8*
National Unemployment Rate (%)	6.1	5.6	5.4	4.9	4.5	*4.3*	*4.4*	*4.6*	*4.7*	*4.8*
Federal Budget Surplus (Unified, FY, $Bill)	-203.1	-163.9	-107.0	-22.0	70.2	*117.0*	*108.0*	*90.0*	*115.0*	*125.0*
Price of Oil ($Bbl., U.S. Refiners' Cost)	15.52	17.24	20.69	19.11	12.66	*14.90*	*16.60*	*17.25*	*17.90*	*18.75*
MONEY AND INTEREST RATES										
Annual Money Supply (M2)	3502	3638	3806	4023	4365	*4609*	*4812*	*5010*	*5220*	*5444*
Yr-to-Yr % Change (Q4/Q4)	0.6	3.9	4.6	5.8	8.5	*5.6*	*4.4*	*4.1*	*4.2*	*4.3*
3-Month Treasury Bill Rate (%)	4.2	5.5	5.0	5.1	4.8	*4.6*	*4.8*	*4.8*	*4.8*	*4.8*
Federal Funds Rate (%)	4.2	5.8	5.3	5.5	5.4	*4.8*	*5.0*	*5.0*	*5.1*	*5.2*
30-Year Treasury Bond Rate (%)	7.4	6.9	6.7	6.6	5.6	*5.6*	*5.6*	*5.6*	*5.7*	*5.8*
AAA Corporate Bond Rate (%)	8.0	7.6	7.4	7.3	6.5	*6.1*	*6.1*	*6.1*	*6.2*	*6.3*
Prime Rate (%)	7.1	8.8	8.3	8.4	8.4	*7.8*	*8.0*	*8.2*	*8.3*	*8.5*
INCOMES										
Personal Income (% Change)	5.0	6.3	5.5	5.6	5.0	*4.8*	*4.6*	*4.6*	*4.6*	*4.7*
Real Disp. Inc. (% Change)	2.4	3.5	2.9	2.8	3.2	*3.1*	*3.3*	*3.0*	*3.0*	*3.0*
Personal Savings Rate (%)	3.8	4.7	4.9	2.1	0.5	*-0.4*	*0.3*	*0.4*	*0.5*	*0.6*
Pretax Corporate Profits ($Bill)	531.2	635.6	680.2	734.4	717.8	*760.0*	*798.0*	*846.0*	*905.0*	*977.0*
Aftertax Corporate Profits ($Bill)	335.9	424.6	454.1	488.3	477.7	*502.0*	*527.0*	*558.0*	*597.0*	*645.0*
Yr-to-Yr % Change	11.9	26.4	9.3	7.5	-2.2	*5.0*	*5.0*	*6.0*	*7.0*	*8.0*
COMPOSITION OF REAL GDP-ANNUAL RATES OF CHANGE										
Gross Domestic Product	3.5	2.3	3.4	3.9	3.9	*3.8*	*2.3*	*2.5*	*2.7*	*2.8*
Final Sales	2.9	2.5	2.8	3.5	4.0	*2.7*	*2.5*	*2.5*	*2.6*	*2.7*
Total Consumption	3.3	2.4	2.6	3.4	4.9	*4.6*	*3.0*	*3.0*	*3.0*	*3.0*
Nonresidential Fixed Investment	8.0	9.0	9.2	10.7	11.8	*8.6*	*6.4*	*5.0*	*5.5*	*6.0*
Construction	1.0	4.3	4.8	7.1	-0.1	*1.0*	*2.5*	*2.5*	*3.0*	*3.5*
Durable Equipment	11.0	10.8	10.9	12.1	16.5	*12.0*	*7.0*	*5.0*	*6.0*	*7.0*
Residential Fixed Investment	10.1	-3.8	5.9	2.5	10.4	*7.0*	*-3.0*	*-1.0*	*1.0*	*2.0*
Exports	8.2	11.1	8.3	12.8	1.5	*1.8*	*5.3*	*7.7*	*7.9*	*7.9*
Imports	12.2	8.9	9.1	13.9	10.6	*9.1*	*5.5*	*4.2*	*5.4*	*7.5*
Federal Government	-3.8	-3.3	-1.3	-1.6	-1.0	*2.4*	*1.4*	*-1.6*	*-1.0*	*-0.6*
State & Local Governments	2.6	2.1	1.6	3.1	2.0	*3.3*	*3.0*	*2.4*	*2.5*	*2.4*

CURRENT STATISTICS

CONSUMER INSTALLMENT CREDIT

NOT SEASONALLY ADJUSTED

BY MAJOR HOLDER

TOTAL OUTSTANDING (101) — BILLION DOLLARS

	JAN.	FEB.	MAR.	APRIL	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	1324.5												
1998	1244.0	1234.2	1236.0	1241.1	1243.1	1256.8	1262.6	1277.0	1287.4	1298.6	1305.8	1333.6	1268.4
1997	1199.6	1190.5	1186.4	1195.6	1199.3	1205.0	1209.2	1220.6	1227.3	1234.3	1237.4	1268.1	1214.4
1996	1117.9	1115.6	1120.5	1129.0	1135.9	1146.9	1157.6	1171.6	1177.3	1180.2	1190.3	1214.9	1154.8
1995	984.6	979.6	989.5	1000.4	1013.6	1028.5	1036.6	1054.9	1074.9	1080.7	1099.7	1128.6	1039.3
1994	855.8	853.0	859.3	869.3	880.3	893.5	899.7	918.6	933.6	944.3	958.8	988.1	904.5
1993	795.1	790.6	786.4	792.7	791.9	797.6	802.7	812.2	820.9	827.2	837.7	863.0	809.8
1992	787.4	779.7	775.6	773.6	772.3	772.8	773.0	779.1	781.3	779.8	784.6	801.0	780.0

COMMERCIAL BANKS (101)

	JAN.	FEB.	MAR.	APRIL	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	506.3												
1998	493.3	492.5	492.1	500.1	497.3	491.4	491.4	498.2	497.9	502.1	498.8	508.9	497.5
1997	521.4	512.9	504.3	510.3	511.6	510.7	514.5	516.2	507.5	507.2	508.3	515.2	511.7
1996	499.4	497.2	497.7	503.9	502.3	505.7	510.2	516.7	517.1	521.3	523.0	529.4	510.3
1995	460.9	459.3	463.0	470.1	473.9	476.3	480.5	490.4	492.4	491.8	496.0	507.8	480.2
1994	398.6	398.4	401.1	408.4	411.7	417.4	423.9	432.7	438.2	443.0	449.0	462.9	423.8
1993	365.3	363.2	362.7	366.3	369.2	370.9	375.4	379.3	383.6	385.8	391.7	399.7	376.1
1992	369.1	364.2	361.3	361.3	359.8	359.1	360.1	360.8	360.4	359.3	360.2	365.5	361.8

FINANCE COMPANIES (101)

	JAN.	FEB.	MAR.	APRIL	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	168.0												
1998	159.5	155.7	156.5	154.3	153.6	154.3	156.1	159.6	159.1	165.6	166.6	168.5	159.1
1997	153.5	153.3	153.8	152.7	154.9	156.7	156.4	157.2	158.4	156.9	156.4	160.0	155.9
1996	152.1	153.9	152.5	154.3	156.1	153.9	155.8	154.7	154.6	151.4	151.0	152.4	153.6
1995	137.1	134.3	135.4	137.4	139.2	141.3	141.7	145.1	145.7	148.2	148.3	152.1	142.2
1994	117.2	117.7	119.8	122.5	121.8	124.0	122.8	124.8	130.0	131.2	132.5	134.4	124.9
1993	116.8	113.4	112.4	112.9	108.3	110.3	111.9	110.7	110.7	111.3	113.4	116.1	112.4
1992	118.9	120.8	118.9	118.7	116.5	117.0	117.4	118.0	117.5	117.1	117.5	118.1	118.0

BY MAJOR TYPE OF CREDIT

AUTOMOBILE (101) — BILLION DOLLARS

	JAN.	FEB.	MAR.	APRIL	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	450.3												
1998	413.5	412.1	415.5	416.0	418.2	425.2	429.7	434.9	439.0	442.3	445.5	449.7	428.5
1997	391.8	389.8	388.9	391.9	393.8	399.6	403.7	405.7	409.8	415.0	412.9	418.9	401.8
1996	363.1	364.3	367.6	369.9	374.1	380.7	385.6	388.4	390.4	392.7	392.1	393.2	380.2
1995	328.2	329.4	331.9	333.2	337.2	341.0	345.4	350.3	354.1	358.2	362.6	364.7	344.7
1994	288.8	289.3	293.2	296.9	301.9	307.3	308.4	314.9	321.5	323.8	326.9	328.6	308.5
1993	262.3	264.5	265.1	266.1	268.3	271.4	273.8	278.1	281.2	286.4	287.3	288.9	274.5
1992	265.1	262.6	262.3	261.8	261.3	259.8	260.5	262.8	264.1	262.7	262.1	263.6	262.4

REVOLVING CREDIT (101)

	JAN.	FEB.	MAR.	APRIL	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	574.9												
1998	541.5	535.3	534.1	535.6	535.6	539.6	537.1	545.0	548.8	555.8	559.0	586.2	546.1
1997	513.5	508.6	503.8	505.8	509.6	511.4	515.1	520.8	524.3	527.5	532.9	555.9	519.1
1996	454.7	453.5	455.1	460.5	466.6	470.3	474.7	480.7	483.3	487.5	497.8	522.9	475.6
1995	378.4	377.8	381.6	385.1	393.8	401.8	404.3	415.1	427.1	432.0	438.7	464.1	408.3
1994	318.1	315.0	316.4	321.0	325.4	331.2	335.9	345.6	346.6	351.5	364.5	383.2	338.0
1993	288.2	283.1	281.8	283.5	285.1	286.9	290.8	294.6	298.3	300.5	308.1	325.0	293.7
1992	270.4	266.0	263.7	264.5	265.5	267.8	267.7	270.6	272.2	274.0	276.8	292.0	270.9

OTHER PERSONAL DEBT HELD BY FINANCIAL INSTITUTIONS (101)

	JAN.	FEB.	MAR.	APRIL	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	299.3												
1998	288.9	286.8	286.4	289.6	289.2	292.0	295.8	297.1	299.6	300.6	301.4	297.7	293.8
1997	294.3	292.0	293.7	297.8	295.9	294.0	290.4	294.1	293.2	291.9	291.6	293.3	293.5
1996	300.1	298.0	297.8	298.6	295.2	295.8	297.3	302.6	303.5	299.9	300.4	298.8	299.0
1995	278.0	272.5	276.0	282.2	282.5	285.8	287.0	289.5	293.7	290.5	298.3	299.8	286.3
1994	248.9	248.8	249.7	251.3	253.0	255.0	255.3	258.1	263.5	268.9	267.3	276.3	258.0
1993	246.7	243.0	239.6	243.2	238.6	239.3	238.1	239.5	241.4	240.3	242.2	249.1	241.8
1992	251.9	251.1	249.6	247.2	245.5	245.1	244.8	245.7	245.1	243.2	245.7	245.2	246.7

INTEREST RATE

PERCENT

CERTIFICATES OF DEPOSIT 3 MONTHS SECONDARY MARKET (9)

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	4.89	4.90											
1998	5.54	5.54	5.58	5.58	5.59	5.60	5.59	5.58	5.41	5.21	5.24	5.14	5.47
1997	5.43	5.37	5.53	5.71	5.70	5.66	5.60	5.60	5.60	5.65	5.74	5.80	5.65
1996	5.39	5.15	5.29	5.36	5.36	5.46	5.53	5.40	5.51	5.41	5.38	5.44	5.39
1995	6.24	6.16	6.15	6.11	6.02	5.90	5.77	5.77	5.73	5.79	5.74	5.62	5.92
1994	3.15	3.43	3.77	4.01	4.51	4.52	4.73	4.81	5.03	5.51	5.79	6.29	4.63
1993	3.19	3.12	3.11	3.09	3.10	3.21	3.16	3.14	3.12	3.24	3.26	3.17	3.18
1992	4.05	4.07	4.25	4.00	3.82	3.86	3.37	3.31	3.13	3.25	3.58	3.48	3.68

BANKERS ACCEPTANCES PRIME 90 DAYS (9)

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	4.80	4.79											
1998	5.48	5.46	5.50	5.48	5.48	5.50	5.50	5.49	5.38	5.12	5.15	5.08	5.39
1997	5.34	5.29	5.44	5.62	5.62	5.59	5.53	5.53	5.54	5.57	5.66	5.75	5.54
1996	5.31	5.07	5.21	5.28	5.29	5.38	5.45	5.32	5.39	5.32	5.29	5.35	5.31
1995	6.12	6.05	6.04	6.00	5.91	5.80	5.66	5.68	5.66	5.71	5.64	5.52	5.82
1994	3.10	3.40	3.73	3.96	4.45	4.45	4.65	4.74	4.95	5.41	5.71	6.18	4.50
1993	3.14	3.06	3.07	3.05	3.06	3.16	3.12	3.10	3.07	3.19	3.29	3.23	3.13
1992	3.97	4.00	4.19	3.92	3.76	3.88	3.42	3.28	3.10	3.24	3.51	3.44	3.64

3 MONTHS TREASURY BILLS AUCTION AVG. NEW ISSUES (10)

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	4.34	4.45											
1998	5.09	5.11	5.03	5.00	5.03	4.99	4.96	4.94	4.74	4.08	4.44	4.42	4.82
1997	5.05	5.00	5.14	5.17	5.13	4.92	5.07	5.13	4.97	4.95	5.15	5.16	5.07
1996	5.02	4.87	4.96	4.99	5.02	5.11	5.17	5.09	5.15	5.01	5.03	4.87	5.02
1995	5.81	5.80	5.73	5.67	5.70	5.50	5.47	5.41	5.26	5.30	5.35	5.16	5.51
1994	3.02	3.21	3.52	3.74	4.19	4.18	4.39	4.50	4.64	4.96	5.25	5.64	4.27
1993	3.06	2.95	2.97	2.89	2.96	3.10	3.05	3.05	2.96	3.04	3.12	3.08	3.02
1992	3.84	3.84	4.05	3.81	3.66	3.70	3.28	3.14	2.97	3.10	3.14	3.25	3.48

6 MONTHS TREASURY BILLS AUCTION AVG. NEW ISSUES (10)

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	4.38	4.43											
1998	5.07	5.07	5.04	5.08	5.15	5.12	5.03	4.97	4.75	4.15	4.43	4.43	4.86
1997	5.11	5.05	5.24	5.35	5.35	5.14	5.12	5.17	5.11	5.09	5.17	5.24	5.18
1996	4.97	4.79	4.96	5.08	5.12	5.26	5.32	5.17	5.29	5.12	5.07	5.02	5.10
1995	6.31	6.10	5.91	5.80	5.73	5.46	5.41	5.40	5.28	5.34	5.29	5.15	5.60
1994	3.19	3.38	3.79	4.13	4.64	4.58	4.81	4.91	5.02	5.39	5.69	6.21	4.65
1993	3.17	3.08	3.08	3.00	3.07	3.23	3.15	3.17	3.06	3.13	3.27	3.25	3.14
1992	3.88	3.94	4.19	3.93	3.78	3.81	3.36	3.23	3.01	3.20	3.35	3.39	3.59

COMPOSITE LONG-TERM GOV'T SECURITIES (over 10 years) (10)

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	5.39	5.60											
1998	5.87	5.94	6.00	5.98	5.99	5.78	5.76	5.64	5.34	5.24	5.43	5.29	5.69
1997	6.89	6.76	7.03	7.18	7.00	6.82	6.55	6.64	6.54	6.37	6.18	6.06	6.67
1996	6.07	6.28	6.72	6.94	7.08	7.20	7.13	6.94	7.13	6.87	6.55	6.63	6.80
1995	7.93	7.69	7.52	7.41	6.99	6.59	6.71	6.90	6.63	6.43	6.31	6.11	6.94
1994	6.24	6.44	6.90	7.32	7.47	7.43	7.61	7.55	7.81	8.02	8.16	7.97	7.41
1993	7.17	6.89	6.65	6.64	6.68	6.55	6.34	6.18	5.94	5.90	6.25	6.27	6.46
1992	7.48	7.78	7.93	7.88	7.80	7.72	7.40	7.19	7.08	7.34	7.43	7.30	7.53

FEDERAL FUNDS SOLD (9)

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	4.63	4.76											
1998	5.56	5.51	5.49	5.45	5.49	5.56	5.54	5.55	5.51	5.07	4.83	4.68	5.35
1997	5.25	5.19	5.39	5.51	5.50	5.56	5.52	5.54	5.54	5.50	5.56	5.50	5.46
1996	5.56	5.22	5.31	5.22	5.24	5.27	5.40	5.22	5.30	5.24	5.31	5.29	5.30
1995	5.53	5.92	5.98	6.05	6.01	6.00	5.85	5.74	5.80	5.76	5.80	5.60	5.84
1994	3.05	3.25	3.34	3.56	4.01	4.25	4.26	4.47	4.73	4.76	5.29	5.45	4.20
1993	3.02	3.03	3.07	2.96	3.00	3.04	3.06	3.03	3.09	2.99	3.02	2.96	3.02
1992	4.03	4.06	3.98	3.73	3.82	3.76	3.25	3.30	3.22	3.12	3.09	2.92	3.52

COMMERCIAL PAPER (10)

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.	AVG.
1999	1185.9												
1998	989.0	1013.1	1057.7	1063.4	1058.3	1098.4	1098.7	1104.2	1150.6	1142.3	1139.6	1161.0	1089.7
1997	810.6	817.6	836.8	853.8	854.3	867.7	878.9	873.6	901.7	913.2	921.5	950.0	873.3
1996	686.7	688.5	694.7	722.6	718.6	731.3	728.0	741.7	754.8	758.2	762.8	777.7	730.5
1995	613.9	622.4	630.2	656.7	646.8	649.3	652.6	652.9	668.6	674.5	672.4	677.7	651.5
1994	559.4	560.3	557.8	553.5	559.9	563.5	572.9	564.6	574.5	592.5	580.7	601.9	570.1
1993	541.4	530.9	535.4	538.7	543.1	542.5	539.7	544.2	541.9	547.4	548.0	555.1	542.4
1992	533.1	530.0	539.0	541.9	538.1	545.0	548.0	546.1	551.0	554.6	556.5	545.6	544.1

DISCOUNT RATES (11)

FEDERAL RESERVE BANK OF NEW YORK DISCOUNT RATES

DATE	RATE	DATE	RATE	DATE	RATE
1981–Nov 2	13	1985–May 24	7 1/2	1991–Feb 1	6–6 1/2
Dec 4	12	1986–Mar 7	7–7 1/2	4	6
1982–July 20	11 1/2	10	7	Apr 30	5 1/2–6
Aug 2	11	Apr 21	6 1/2–7	May 2	5 1/2
16	10 1/2	July 11	6	Nov 7	4 1/2
27	10	Aug 21	5 1/2–6	Dec 20	3 1/2
Oct 12	9 1/2	22	5 1/2	1992–July 2	3
Nov 22	9	1987–Sept 4	5 1/2–6	1994–May 17	3 1/2
Dec 15	8 1/2	11	6	Aug 16	4
1984–Apr 9	9	1988–Feb 24	6 1/2–7	Nov 15	4 3/4
Nov 21	8 1/2	27	7	1995–Feb 1	5 1/4
Dec 24	8	1990–Dec 19	6 1/2	1996–Jan 31	5
				1998–Oct 15	4 3/4
				Nov 17	4 1/2

PRIME RATE (11)

Charged by banks

DATE	RATE	DATE	RATE	DATE	RATE
1981–July 8	20 1/2	1984–Mar 19	11 1/2	1988–Jan 1	8 3/4
Sept 15	20	April 5	12	Feb 2	8 1/2
22	19	May 8	12 1/2	May 11	9
Oct 5	19	June 25	13	July 14	9 1/2
13	18	Sept 27	12 3/4	Aug 11	10
Nov 3	17 1/2	Oct 17	12 1/2	Nov 28	10 1/2
9	16 1/2–17	29	12	1989–Feb 10	11
17	17	Nov 9	11 3/4	24	11 1/2
20	16 1/2	28	11 1/4	June 5	11
Dec 1	15 3/4	Dec 20	10 3/4	July 31	10 1/2
1982–Feb 2	16 1/6	1985–Jan 15	10 1/2	1990–Jan 8	10
18	17	May 20	10	1991–Jan 2	9 1/2
23	16 1/2	June 18	9 1/2	Feb 4	9
July 20	16	1986–Mar 7	9	May 1	8 1/2
29	15 1/2	April 21	8 1/2	Sept 13	8
Aug 2	15	July 14	8	Nov 7	7 1/2
16	14 1/2	Aug 26	7 1/2	Dec 23	7 1/2-6 1/2
18	14	1987–May 1	8	Dec 24	6 1/2
23	13 1/2	May 15	8 1/4	1992-July 2	6
Sept 30	13 1/2	Sept 9	8 3/4	1994-Mar 24	6 1/4
Oct 7	13	Oct 7	9 1/4	April 19	6 3/4
14	12	15	9 1/4–9 3/4	May 17	7 1/4
Nov 22	11 1/2	21	9 1/4	Aug 16	7 3/4
1983–Jan 11	11	22	9	Nov 15	8 1/2
Feb 28	10 1/2	Nov 5	8 3/4	1995-Feb 1	9
Aug 8	11			July 7	8 3/4
				Dec 19	8 1/2
				1996-Feb 1	8 1/4
				1997-Mar 26	8 1/2
				1998-Sept 30	8 1/4
				Oct 16	8
				Nov 18	7 3/4

Figures in parentheses indicate the page of Basic Statistics on which sources, complete description, and earlier data are published.

U.S. GOVERNMENT BOND YIELDS

Yield to Maturity, in Percent

TAXABLE ISSUES

LONG TERM MATURITIES*

Monthly Averages of Weekly Indexes

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Avg.
1948	2.44	2.44	2.44	2.44	2.42	2.41	2.44	2.43	2.43	2.43	2.43	2.42	2.43
1949	2.40	2.38	2.37	2.37	2.37	2.37	2.24	2.21	2.19	2.18	2.16	2.15	2.28
1950	2.17	2.22	2.25	2.28	2.30	2.33	2.34	2.35	2.37	2.38	2.39	2.41	2.32
1951	2.40	2.41	2.52	2.60	2.68	2.69	2.68	2.60	2.58	2.65	2.69	2.72	2.60
1952	2.74	2.72	2.71	2.64	2.58	2.62	2.60	2.69	2.70	2.74	2.70	2.74	2.68
1953	2.79	2.81	2.89	2.94	3.08	3.10	2.98	2.97	2.93	2.79	2.81	2.76	2.90
1954	2.65	2.58	2.49	2.44	2.51	2.52	2.44	2.45	2.49	2.51	2.54	2.56	2.52
1955	2.65	2.71	2.70	2.77	2.76	2.77	2.87	2.91	2.88	2.82	2.84	2.89	2.80
1956	2.87	2.81	2.90	3.05	2.94	2.90	2.97	3.15	3.21	3.20	3.29	3.41	3.06
1957	3.37	3.21	3.28	3.33	3.44	3.66	3.67	3.68	3.67	3.75	3.48	3.07	3.47
1958	2.97	2.98	2.94	2.79	2.84	2.92	3.11	3.40	3.60	3.71	3.68	3.79	3.23
1959	3.91	3.90	3.90	3.98	4.06	4.07	4.08	4.05	4.35	4.21	4.22	4.42	4.10
1960	4.47	4.26	4.11	4.17	4.15	3.93	3.78	3.71	3.72	3.85	3.88	3.87	3.99
1961	3.87	3.78	3.76	3.79	3.72	3.89	3.90	4.01	4.00	3.98	3.99	4.11	3.90
1962	4.10	4.11	4.01	3.89	3.87	3.89	4.01	3.97	3.94	3.89	3.88	3.87	3.95
1963	3.90	3.95	3.96	4.00	4.00	4.01	4.02	4.00	4.06	4.09	4.13	4.16	4.02
1964	4.16	4.14	4.19	4.22	4.18	4.15	4.14	4.15	4.17	4.18	4.15	4.16	4.17
1965	4.16	4.16	4.15	4.16	4.16	4.16	4.17	4.21	4.28	4.30	4.36	4.45	4.23
1966	4.46	4.64	4.65	4.58	4.61	4.67	4.77	4.84	4.82	4.73	4.75	4.68	4.68
1967	4.43	4.49	4.50	4.56	4.81	4.92	4.92	5.01	5.04	5.24	5.48	5.44	4.90
1968	5.26	5.24	5.48	5.34	5.45	5.32	5.15	5.11	5.15	5.31	5.42	5.74	5.33
1969	5.85	5.95	6.17	5.95	5.99	6.22	6.21	6.12	6.38	6.38	6.61	6.86	6.22
1970	6.91	6.59	6.61	6.71	7.11	7.17	6.77	6.93	6.79	6.77	6.51	6.18	6.75
1971	6.06	5.96	5.74	5.79	6.19	6.23	6.19	6.09	5.83	5.72	5.64	5.78	5.94
1972	5.73	5.77	5.76	5.85	5.74	5.69	5.67	5.55	5.62	5.65	5.43	5.57	5.67
1973	5.89	6.09	6.16	6.07	6.11	6.17	6.35	6.69	6.11	5.89	5.92	5.99	6.12
1974	6.25	6.22	6.52	6.74	6.69	6.57	6.67	6.78	6.79	6.81	6.54	6.44	6.59
1975	7.98	7.81	8.05	8.34	8.21	8.08	8.20	8.53	8.53	8.36	8.26	8.20	8.21
1976	8.01	8.01	7.93	7.77	8.09	8.04	8.01	7.94	7.81	7.72	7.71	7.35	7.87
1977	7.49	7.71	7.74	7.68	7.73	7.60	7.61	7.64	7.60	7.74	7.80	7.93	7.69
1978	8.15	8.23	8.20	8.33	8.44	8.49	8.65	8.42	8.44	8.62	8.70	8.86	8.46
1979	8.93	9.00	9.01	9.05	9.13	8.85	8.86	8.90	9.13	9.90	10.34	10.11	9.27
1980	10.53	12.25	12.28	11.18	10.13	9.80	10.21	11.00	11.28	11.70	12.12	12.21	11.22
1981	11.88	12.64	12.48	12.98	13.44	12.71	13.37	13.84	14.48	14.38	12.96	13.28	13.20
1982	14.10	13.90	13.16	13.08	12.88	13.61	13.44	12.53	11.86	10.71	10.30	10.52	12.51
1983	10.58	10.88	10.56	10.42	10.41	10.90	11.33	11.69	11.51	11.44	11.59	11.78	11.09
1984	11.61	11.76	12.28	12.59	13.31	13.46	13.22	12.60	12.33	11.96	11.52	11.40	12.34
1985	11.36	11.46	11.82	11.46	11.00	10.31	10.48	10.54	10.57	10.44	10.00	9.43	10.74
1986	9.41	8.94	8.16	7.58	8.06	8.29	7.89	7.75	7.99	8.11	7.85	7.68	8.14
1987	7.64	7.77	7.65	8.36	8.92	8.76	8.86	9.14	9.78	9.80	9.16	9.24	8.76
1988	8.97	8.53	8.74	9.03	9.40	9.16	9.41	9.50	9.18	9.08	9.14	9.16	9.11
1989	9.14	9.17	9.36	9.20	8.95	8.39	8.27	8.28	8.36	8.23	8.06	8.07	8.62
1990	8.43	8.78	8.79	8.99	8.98	8.70	8.72	9.00	9.21	9.05	8.70	8.38	8.81
1991	8.45	8.22	8.48	8.38	8.42	8.65	8.57	8.19	8.06	7.94	7.92	7.62	8.24
1992	7.57	7.85	7.99	7.96	7.87	7.83	7.51	7.27	7.20	7.38	7.48	7.35	7.61
1993	7.25	6.96	6.69	6.66	6.64	6.56	6.34	6.19	5.91	5.87	6.21	6.23	6.46
1994	6.28	6.44	6.89	7.32	7.50	7.47	7.68	7.54	7.83	8.07	8.18	7.97	7.43
1995	7.96	7.74	7.59	7.49	7.02	6.65	6.81	6.96	6.69	6.49	6.37	6.16	6.99
1996	6.12	6.37	6.75	6.98	7.09	7.25	7.14	6.98	7.19	6.92	6.58	6.70	6.84
1997	6.93	6.81	7.05	7.18	7.04	6.86	6.57	6.65	6.56	6.42	6.20	6.08	6.69

Annual Range, and Close, of Weekly Indexes†

Year	High	Low	Close
1948	2.44	2.38	2.41
1949	2.40	2.14	2.14
1950	2.42	2.15	2.41
1951	2.74	2.39	2.74
1952	2.78	2.56	2.78
1953	3.15	2.70	2.70
1954	2.70	2.41	2.57
1955	2.95	2.62	2.90
1956	3.52	2.80	3.43
1957	3.80	3.04	3.05
1958	3.84	2.73	3.84
1959	4.55	3.84	4.55
1960	4.58	3.68	3.72
1961	4.11	3.69	4.12
1962	4.16	3.84	3.88
1963	4.18	3.88	4.18
1964	4.22	4.12	4.18
1965	4.49	4.14	4.47
1966	4.90	4.44	4.63
1967	5.55	4.38	5.46
1968	5.98	5.05	5.83
1969	6.95	5.80	6.91
1970	7.44	6.04	6.31
1971	6.37	5.52	5.72
1972	5.87	5.36	5.68
1973	6.92	5.72	6.13
1974	6.85	6.10	6.72
1975	8.63	7.77	8.04
1976	8.15	7.27	7.27
1977	8.02	7.26	8.02
1978	8.95	8.04	8.92
1979	10.59	8.74	10.17
1980	12.68	9.55	11.86
1981	15.08	11.52	13.71
1982	14.32	10.18	10.44
1983	11.99	10.18	11.76
1984	13.89	11.25	11.38
1985	11.84	9.24	9.24
1986	9.51	7.23	7.79
1987	10.30	7.57	9.12
1988	9.60	8.44	9.19
1989	9.50	7.97	8.17
1990	9.32	8.22	8.48
1991	8.70	7.36	7.36
1992	8.07	7.07	7.29
1993	7.35	6.14	6.20
1994	8.22	6.15	7.94
1995	7.98	6.11	6.11
1996	7.36	6.04	6.75
1997	7.23	5.98	6.08

Weekly Indexes

1994

Week	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
1	6.38	6.25	6.74	7.33	7.46	7.48	7.69	7.41	7.68	8.09	8.21	8.01
2	6.15	6.43	6.85	7.34	7.70	7.34	7.76	7.63	7.79	8.01	8.18	7.98
3	6.29	6.44	6.82	7.42	7.36	7.47	7.60	7.50	7.92	8.00	8.20	7.95
4	6.28	6.64	6.84	7.20	7.47	7.49	7.66	7.59	7.94	8.17	8.22	7.94
5	———	———	7.19	———	———	7.59	———	7.55	———	———	8.09	———
Avg.	6.28	6.44	6.89	7.32	7.50	7.47	7.68	7.54	7.83	8.07	8.18	7.97

1994: High, 8.22, November; Low, 6.15, January; Average, 7.43

1995

Week	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
1	7.97	7.84	7.59	7.52	7.37	6.64	6.70	6.93	6.68	6.59	6.39	6.14
2	7.97	7.75	7.71	7.50	7.09	6.68	6.62	6.98	6.68	6.54	6.33	6.17
3	7.90	7.71	7.50	7.50	6.97	6.65	6.97	7.02	6.62	6.42	6.40	6.22
4	7.98	7.67	7.61	7.44	6.87	6.61	6.96	7.05	6.78	6.41	6.40	6.11
5	———	———	7.54	———	6.79	———	———	6.82	———	———	6.33	———
Avg.	7.96	7.74	7.59	7.49	7.02	6.65	6.81	6.96	6.69	6.49	6.37	6.16

1995: High, 7.98, January; Low, 6.11, December; Average, 6.99

1996

Week	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
1	6.04	6.20	6.57	6.81	7.09	7.14	7.07	6.88	7.26	6.96	6.67	6.51
2	6.25	6.18	6.85	7.10	7.20	7.36	7.24	6.92	7.27	6.94	6.59	6.74
3	6.08	6.50	6.70	7.00	7.04	7.28	7.15	6.98	7.16	6.97	6.54	6.82
4	6.11	6.61	6.86	7.02	7.00	7.20	7.16	7.14	7.06	6.94	6.53	6.68
5	6.10	———	———	———	7.11	———	7.09	———	———	6.77	———	6.75
Avg.	6.12	6.37	6.75	6.98	7.09	7.25	7.14	6.98	7.19	6.92	6.58	6.70

1996: High, 7.36, June; Low, 6.04, January; Average, 6.84

1997

Week	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
1	6.93	6.83	6.97	7.20	7.04	6.95	6.79	6.54	6.67	6.39	6.30	6.10
2	6.88	6.80	7.00	7.22	6.97	6.90	6.62	6.72	6.72	6.42	6.21	6.17
3	6.91	6.69	7.11	7.23	7.04	6.77	6.54	6.62	6.45	6.45	6.13	6.09
4	6.99	6.92	7.12	7.19	7.11	6.80	6.49	6.73	6.39	6.48	6.15	5.98
5	———	———	———	7.04	———	———	6.39	———	———	6.35	———	6.06
Avg.	6.93	6.81	7.05	7.18	7.04	6.86	6.57	6.65	6.56	6.42	6.20	6.08

1997: High, 7.23, April; Low, 5.98, December; Average, 6.69

*Based on the median yield to maturity of a varying number of bonds, depending upon the issues available. List used is restricted to those issues with more than twenty years to maturity.
†Closes are last Wednesday of each year.
Note: Series revised beginning 1975.

THE ECONOMIC AND BUDGET OUTLOOK: AN UPDATE

July 1, 1999

NOTES

The figures in this report use shaded vertical bars to indicate periods of recession. Those bars extend from the peak to the trough of the recession.

Unemployment rates throughout the report are calculated on the basis of the civilian labor force.

Numbers in the text and tables may not add up to totals because of rounding.

Preface

This volume is one in a series of reports on the state of the economy and the budget that the Congressional Budget Office (CBO) issues each year. It satisfies the requirement of section 202(e) of the Congressional Budget Act of 1974 for CBO to submit periodic reports to the Committees on the Budget with respect to fiscal policy and to provide five-year baseline projections of the federal budget. The budget resolution for fiscal year 2000 required CBO to publish this report by July 1, 1999. In accordance with CBO's mandate to provide objective and impartial analysis, the report contains no recommendations.

In view of the accelerated schedule for this volume, additional supporting materials (listed in the table of contents) will be made available on CBO's World Wide Web site (www.cbo.gov) during the month of July.

The analysis of the economic outlook was prepared by the Macroeconomic Analysis Division under the direction of Robert Dennis, Kim J. Kowalewski, and John F. Peterson. David Brauer was the lead author for the economic section. The baseline outlay projections were prepared by the staff of the Budget Analysis Division under the supervision of Paul N. Van de Water, Robert Sunshine, Priscilla Aycock, Thomas Bradley, Paul Cullinan, Peter Fontaine, James Horney, and Michael Miller. The revenue estimates were prepared by the staff of the Tax Analysis Division under the supervision of Thomas Woodward and Richard Kasten. Jeffrey Holland wrote the introduction and the section on the budget outlook.

An early version of the economic forecast underlying this report was discussed at a meeting of CBO's Panel of Economic Advisers on June 2, 1999. Members of the panel are Alan J. Auerbach, Martin N. Baily, Jagdish Bhagwati, Michael Boskin, Barry P. Bosworth, John Cogan, Robert Dederick, William C. Dudley, Martin Feldstein, Robert J. Gordon, David Hale, Robert E. Hall, N. Gregory Mankiw, Allan Meltzer, William Niskanen, William D. Nordhaus, June E. O'Neill, Rudolph Penner, James Poterba, Robert

Reischauer, Joel Slemrod, John Taylor, and Martin B. Zimmerman. Rudy Boschwitz, John Makin, Mark McClellan, William McGuire, and Joan Trauner attended as guests. Although those outside advisers provided considerable assistance, they are not responsible for the contents of this report.

Sherry Snyder and Christian Spoor edited the report, and Leah Mazade proofread it. The authors owe thanks to Marion Curry and Linda Lewis Harris, who assisted in preparing the many drafts. Kathryn Quattrone prepared the report for final publication, and Laurie Brown prepared the electronic versions for CBO's Web site.

Dan L. Crippen
Director
July 1, 1999

Contents

The following supporting documents will be posted on CBO's World Wide Web site (www.cbo.gov) during July:

Extended Discussion of CBO's July 1999 Economic Outlook (Now available)

Evaluating CBO's Record of Economic Forecasts

The Federal Sector of the National Income and Product Accounts

The Budget Adjusted for Effects of the Business Cycle

The Long-Term Budget Outlook: An Update

TABLES

FIGURES

BOX

The Congressional Budget Office (CBO) estimates that the total budget surplus will jump from $69 billion in fiscal year 1998 to $120 billion in 1999 and $161 billion in 2000. Those projections assume that current laws affecting revenues and entitlement programs do not change and that the Congress complies with the statutory caps on discretionary outlays. When the off-budget spending and revenues of Social Security and the Postal Service are excluded, the remaining on-budget transactions are projected to show a surplus of $14 billion in 2000. By either measure of the surplus, though, the beneficial effects on the budget of the prolonged economic expansion that began in 1991, combined with slower growth in entitlement spending and reduced levels of debt held by the public, lead CBO to project a sustained period of rising surpluses.

Growth in real (inflation-adjusted) gross domestic product (GDP) has averaged around 4 percent annually over the past three years and is expected to maintain that rate in 1999. Even though such rapid growth has pushed the unemployment rate down to 4.2 percent, it has not sparked inflation--the consumer price index (CPI) rose by only 1.6 percent in calendar year 1998 and is anticipated to grow by about 2.2 percent this year.

Next year, CBO expects growth in output (GDP) to slow and inflation to rise. One reason is that continued rapid growth this year and expectations of higher inflation are likely to cause the Federal Reserve to raise interest rates modestly over the next several months.

Looking beyond 2000, CBO projects that real growth will average 2.4 percent a year through 2009. That rate marks a significant drop from the 4 percent average annual growth of the past three years, but it still represents a healthy increase in the economy that will keep the budget in good shape.

CBO now projects larger budget surpluses than it estimated in April, when it last assessed the budget outlook.(1) The cumulative total budget surplus over the 1999-2009 period is projected to be more than $300 billion higher and the on-budget surplus more than $180 billion higher. Although the increase in the total surplus may sound large, it equals just 1.2 percent of the revenues projected to flow into government coffers during that period.

The more optimistic projections of the surplus result from changes in economic and other factors that will increase revenues and reduce spending. In particular, slightly more optimistic projections of GDP and inflation (among other economic variables) have led CBO to increase its projection of the cumulative surplus by $275 billion between 1999 and 2009. The only piece of legislation enacted since April with a notable impact on the budget--the 1999 Emergency Supplemental Appropriations Act--lowers projected surpluses by a total of $40 billion over the next 11 years. Overall, revisions to CBO's estimates raise its projections of the total budget surplus by $10 billion in 1999 and an average of about $30 billion a year thereafter. Under current laws and policies (and providing that the economy performs as CBO assumes), the surplus is projected to climb to $413 billion in 2009. Cumulative on-budget surpluses are projected to total nearly $1 trillion between 1999 and 2009. During that same period, cumulative off-budget surpluses will total slightly more than $2 trillion.

The Economic Outlook

CBO now forecasts significantly stronger economic growth in calendar years 1999 and 2000 than it did in January, when it published its previous economic outlook. The new forecast assumes that growth will continue at about the current pace through the rest of this year (see Table 1).(2) Inflation, as measured by either the CPI or the GDP price index, is projected to increase modestly in 1999. However, continued strong growth this year, combined with expectations of higher inflation, will most likely prompt the Federal Reserve to increase the federal funds rate (the overnight interest rate that banks charge one another). Such an increase will help slow the economy next year and cap the inflation rate.

Table 1.
The CBO Forecast for 1999 and 2000

	Actual 1998	Forecast 1999	Forecast 2000
Fourth Quarter to Fourth Quarter (Percentage change)			
Nominal GDP	5.2	5.2	4.0
Real GDP[a]	4.3	3.6	2.1
GDP Price Index[b]	0.9	1.6	1.9
Consumer Price Index[c]	1.5	2.5	2.4
Calendar Year Average (Percent)			
Real GDP[a]	3.9	4.0	2.4
Unemployment Rate	4.5	4.2	4.3
Three-Month Treasury Bill Rate	4.8	4.6	5.0
Ten-Year Treasury Note Rate	5.3	5.6	5.9

SOURCES: Congressional Budget Office; Department of Commerce, Bureau of Economic Analysis; Federal Reserve Board; Department of Labor, Bureau of Labor Statistics.

a. Based on chained 1992 dollars.

b. The GDP price index is virtually the same as the implicit GDP deflator.

c. The consumer price index for all urban consumers.

The Forecast for 1999 and 2000

Real GDP grew at an annualized rate of 4.3 percent in the first quarter of 1999 and shows few signs of slowing. Strong growth is projected to continue in the near term for a number of reasons. First, although CBO expects the growth of consumer spending to slow from its recent breakneck pace, strong incomes and the lingering effects of the increase in wealth from rising stock prices will keep real growth of consumption robust for the rest of 1999, at roughly 3.5 percent. Second, businesses' investment spending will probably continue at a rapid pace as the cost of capital remains fairly low and companies substitute productivity-enhancing capital equipment for increasingly scarce labor. Third, concerns about the Year 2000 (Y2K) computer problem may also spur growth in 1999 as businesses stockpile inventories in anticipation of possible disruptions in their supply. In the other direction, residential construction is likely to slow in 1999 in response to higher mortgage rates this spring and perhaps to shortages of labor and materials for construction.

Long-term interest rates have risen sharply in recent weeks, and prices in the futures market for federal funds suggest that the Federal Reserve will tighten its monetary policy in the next several months. Last fall, concern that dislocations in financial markets would stall the U.S. economy and threaten global recession prompted the Federal Reserve to reduce the target federal funds rate by 75 basis points (0.75 percentage points). The easing of the Asian crisis and of financial-market problems has mostly removed those concerns. Following the May 18 meeting of the Federal Open Market Committee, the Federal Reserve announced that it was leaning toward monetary tightening, citing "ongoing strength in demand" and "the potential for a buildup of inflationary imbalances." CBO's forecast assumes that the federal funds rate will be raised by a total of 50 basis points in 1999. That assumption is reflected in the increase in CBO's forecast for interest rates on three-month Treasury bills (see Tables 2 and 3).(3)

Table 2.
Comparison of the CBO Economic Projections for Calendar Years 1999-2009

		Forecast		Projected								
	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Nominal GDP (Billions of dollars)												
July 1999	8,511	8,964	9,351	9,751	10,159	10,583	11,027	11,508	12,017	12,554	13,113	13,695
January 1999	8,499[a]	8,846	9,182	9,581	10,015	10,476	10,960	11,465	11,988	12,528	13,089	13,668
Nominal GDP (Percentage change)												
July 1999	4.9	5.3	4.3	4.3	4.2	4.2	4.2	4.4	4.4	4.5	4.5	4.4
January 1999	4.8[a]	4.1	3.8	4.3	4.5	4.6	4.6	4.6	4.6	4.5	4.5	4.4
Real GDP (Percentage change)												
July 1999	3.9	4.0	2.4	2.4	2.3	2.3	2.3	2.5	2.5	2.5	2.5	2.5
January 1999	3.7[a]	2.3	1.7	2.2	2.4	2.4	2.4	2.4	2.4	2.3	2.3	2.3
GDP Price Index[b] (Percentage change)												
July 1999	1.0	1.3	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9
January 1999	1.0[a]	1.7	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Consumer Price Index[c] (Percentage change)												
July 1999	1.6	2.2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
January 1999	1.6	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Unemployment Rate (Percent)												
July 1999	4.5	4.2	4.3	4.6	4.9	5.1	5.3	5.4	5.5	5.5	5.5	5.5
January 1999	4.5	4.6	5.1	5.4	5.6	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Three-Month Treasury Bill Rate (Percent)												
July 1999	4.8	4.6	5.0	4.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
January 1999	4.8	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Ten-Year Treasury Note Rate (Percent)												

2 yr forecast LT Proj

July 1999	5.3	5.6	5.9	5.5	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
January 1999	5.3	5.1	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Tax Bases (Percentage of GDP)												
Corporate profits												
July 1999	8.4	8.1	7.3	7.4	7.5	7.4	7.4	7.3	7.3	7.3	7.2	7.2
January 1999	8.5	8.1	7.4	7.6	7.7	7.8	7.9	7.9	7.9	7.8	7.7	7.5
Wages and salaries												
July 1999	48.8	49.2	49.5	49.3	49.2	49.2	49.2	49.3	49.3	49.3	49.3	49.3
January 1999	48.8	49.3	49.7	49.5	49.3	49.2	49.1	49.1	49.1	49.1	49.1	49.1

SOURCES: Congressional Budget Office; Department of Commerce, Bureau of Economic Analysis; Federal Reserve Board; Department of Labor, Bureau of Labor Statistics.

NOTE: Percentage change is year over year. Corporate profits are book profits.

a. Based on data for the first three quarters of 1998 published November 24, 1998.

b. The GDP price index is virtually the same as the implicit GDP deflator.

c. The consumer price index for all urban consumers.

Table 3.
The CBO Economic Projections for Fiscal Years 1999-2009

	Actual	Forecast		Projected								
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Nominal GDP (Billions of dollars)	8,404	8,851	9,259	9,652	10,055	10,476	10,913	11,385	11,887	12,418	12,972	13,547
Nominal GDP (Percentage change)	5.0	5.3	4.6	4.2	4.2	4.2	4.2	4.3	4.4	4.5	4.5	4.4
Real GDP (Percentage change)	3.8	4.1	2.8	2.3	2.3	2.3	2.3	2.4	2.5	2.5	2.5	2.5
GDP Price Index[a] (Percentage change)	1.2	1.1	1.8	1.9	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9
Consumer Price Index[b] (Percentage change)	1.6	1.9	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Unemployment Rate (Percent)	4.6	4.3	4.2	4.5	4.8	5.1	5.3	5.4	5.5	5.5	5.5	5.5
Three-Month Treasury Bill Rate (Percent)	5.0	4.5	5.0	4.8	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Ten-Year Treasury Note Rate (Percent)	5.6	5.2	5.9	5.6	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Tax Bases (Percentage of GDP)												

Corporate profits	8.6	8.2	7.5	7.4	7.5	7.4	7.4	7.3	7.3	7.3	7.3	7.2
Wages and salaries	48.6	49.1	49.5	49.4	49.2	49.2	49.2	49.3	49.3	49.3	49.3	49.3

SOURCES: Congressional Budget Office; Department of Commerce, Bureau of Economic Analysis; Federal Reserve Board; Department of Labor, Bureau of Labor Statistics.

NOTE: Percentage change is year over year. Corporate profits are book profits.

a. The GDP price index is virtually the same as the implicit GDP deflator.

b. The consumer price index for all urban consumers.

Higher interest rates will slow the economy in 2000 through several channels. CBO anticipates a pronounced slowdown in fixed investment, especially in residential construction. At the same time, with interest rates rising and greater growth in compensation putting pressure on profits, stock prices are unlikely to continue increasing at the rate of the past several years. Consequently, the boost to consumer spending from higher stock prices should gradually diminish. Higher interest rates will also help keep the dollar strong; thus, the trade deficit will most likely remain a drag on U.S. output in 2000. In addition, any excess inventory buildup related to Y2K fears will need to be worked off. For all of those reasons, CBO anticipates that growth of real GDP will slow from 4 percent in 1999 to 2.4 percent next year.

Inflation is forecast to rise modestly in both 1999 and 2000, in part because of higher energy prices. In addition, prices of imports other than oil, which have declined during the past two years, and prices for medical care, which have helped keep inflation down in recent years, may reverse course. And with labor markets still exceptionally tight, growth in compensation is likely to speed up.

The Outlook After 2000

CBO does not forecast the ups and downs of the economy more than two years ahead. Its projections beyond that period simply extend historical patterns in the factors that underlie the trend growth of real GDP--factors such as the growth of the labor force, the growth of productivity, and the rate of national saving (see Table 4). Rapid growth in the past three years has driven real GDP above CBO's estimate of potential GDP (the highest level of real GDP that could persist for a substantial period without raising the rate of inflation). Therefore, CBO assumes that real GDP will grow more slowly than potential GDP after 2000 to close the gap between the two and reduce inflationary pressures (see Figure 1).

Table 4.
Key Assumptions for the CBO Projection of Potential Output (By calendar year)

	Average Annual Growth Rate (Percent)						
	1949-1998	1949-1960	1960-1969	1969-1980	1980-1990	1990-1998	1998-2009 (Projection)
Overall Economy							
Working-Age Population	1.3	0.8	1.4	2.0	1.1	1.0	1.0
Potential Labor Force	1.7	1.0	1.6	2.7	1.6	1.1	1.0
Potential Labor Force Productivity[a]	1.6	2.7	2.4	0.6	1.0	1.2	1.7
Excluding new price indexes	1.6	2.7	2.5	0.6	1.0	1.0	1.4
Effect of new price indexes	n.a.	n.a.	n.a.	n.a.	n.a.	0.1	0.3
Potential Real GDP	3.3	3.8	4.1	3.3	2.6	2.4	2.8
Real GDP	3.4	3.9	4.6	2.8	2.9	2.6	2.6
Nonfarm Business Sector							
Potential Employment	1.8	1.2	1.7	2.8	1.7	1.4	1.1
Potential Hours Worked	1.5	1.0	1.3	2.1	1.6	1.4	1.1
Capital Input	3.7	3.4	4.3	4.1	3.6	3.1	4.1
Potential Total Factor Productivity	1.3	2.0	2.0	1.1	0.5	0.7	1.1
Potential Labor Force Productivity[b]	1.9	2.7	2.9	1.7	1.0	1.3	2.0
Excluding new price indexes	1.9	2.7	2.9	1.7	1.0	1.1	1.5
Effect of new price indexes	n.a.	n.a.	n.a.	n.a.	n.a.	0.2	0.5
Potential Real Output	3.5	3.8	4.3	3.8	2.7	2.7	3.1

SOURCE: Congressional Budget Office using data from the Department of Labor, Bureau of Labor Statistics, and the Department of Commerce, Bureau of Economic Analysis.

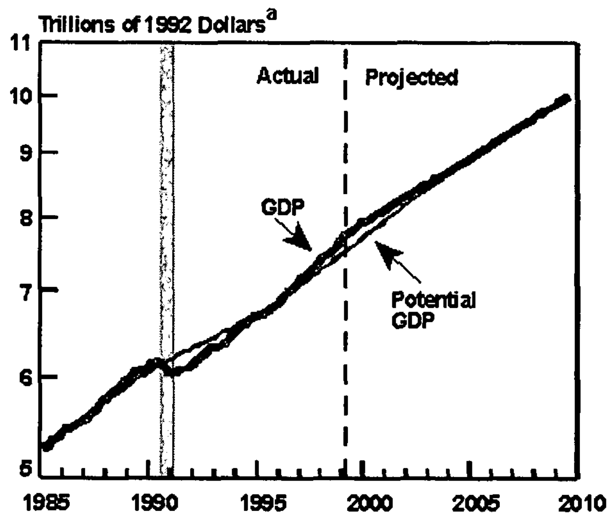
NOTES: The years marking the ends of historical periods (except 1998) are years in which the business cycle peaked.

n.a. = not applicable.

a. Growth in potential output per labor force member.

b. Growth in potential output per hour in the nonfarm business sector.

Figure 1.
GDP and Potential GDP



SOURCES: Congressional Budget Office; Department of Commerce, Bureau of Economic Analysis.

NOTE: Values are plotted using a logarithmic scale.

a. Chain weighted.

The current projection for growth of potential GDP--about 2.7 percent a year through 2009--is roughly 0.2 percentage points higher than CBO estimated in January. Half of that difference results from faster projected growth in the capital stock (4.1 percent, up from 3.8 percent last winter) caused by a higher projected rate of business investment that partly reflects larger budget surpluses.

The other half stems from two additional factors. First, CBO has revised its estimate of the technical adjustment that it incorporates into its projections to account for methodological changes to various price indexes. That adjustment reflects the effect on inflation and growth of real GDP from changes in the methods used to calculate the CPI and the price indexes based on the national income and product accounts. Such changes reduce the measured rate of inflation without affecting nominal GDP, thus raising the growth of real GDP. CBO has increased its estimate of the technical adjustment by less than 0.1 percentage point a year, on average, for the 1999-2009 period.

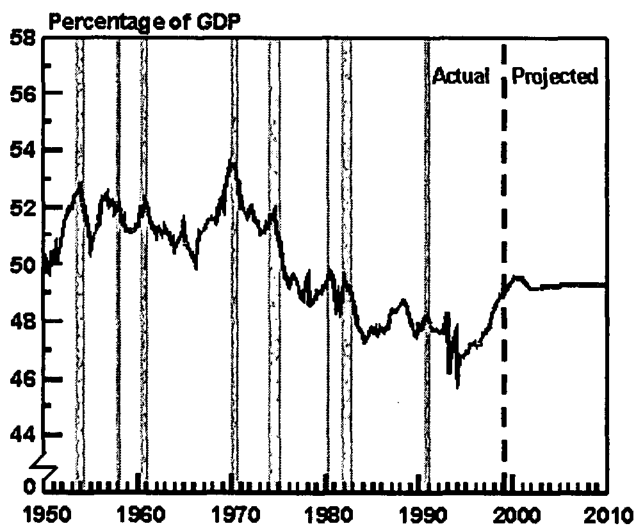
Second, CBO has raised its projection of the growth of total factor productivity slightly to reflect the possibility that part of the recent boom in such growth may be permanent. (The growth of total factor productivity is the growth of output beyond that accounted for by the growth of labor and capital.) Some analysts have argued that the spread of free-market principles around the world, the increase in international trade, the rapid pace of investment in computers and information technology, and the apparent increase in the ability and motivation of managers to innovate will foster stronger productivity growth for years to come. Although those arguments rely on anecdotal evidence, there are few corresponding arguments that would imply significantly slower productivity growth. Thus, CBO has assumed a small increase in productivity growth above and beyond the effects of measurement changes and faster growth in the capital stock.

Taxable Income

Projections of federal revenues are closely linked to projections of national income. However, different components of income are taxed at different rates, and some are not taxed at all. Thus, the distribution of national income among its various components is one of the most important parts of CBO's economic projections. Wage and salary disbursements and corporate profits are of special interest because they are taxed at the highest effective rates. Together, those two sources of income are expected to decline as a share of GDP by about 0.8 percentage points between 1999 and 2009 (see Table 2).

In response to tight labor markets, wage and salary disbursements are forecast to rise slightly as a percentage of GDP--reaching 49.5 percent in 2000. They are then projected to fall slightly--to an average of about 49.3 percent from 2001 through 2009--as gains in compensation relative to productivity diminish (see Figure 2).

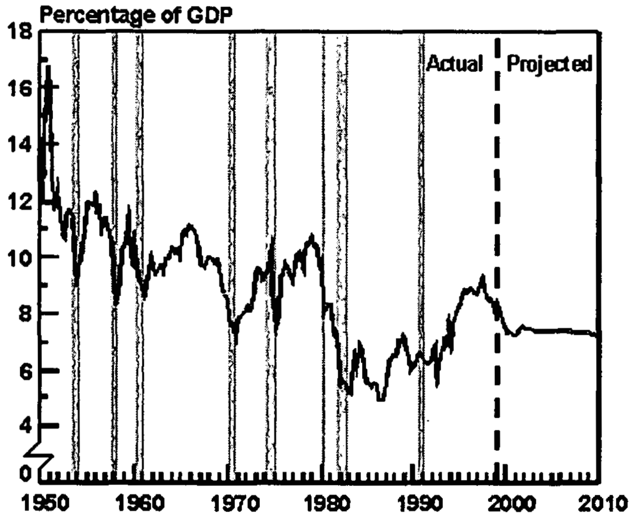
Figure 2.
Wage and Salary Disbursements



SOURCES: Congressional Budget Office; Department of Commerce, Bureau of Economic Analysis.

CBO projects that corporate profits (measured as book profits) will decline as a share of GDP as the economy slows, falling from 8.1 percent in 1999 to 7.3 percent in 2000 and then averaging 7.3 percent through 2009 (see Figure 3). Profits' share of GDP rose dramatically between 1992 and 1997. Although it eased back in 1998, it is still high compared with the average of the past 20 years. The recent increase stemmed from a sharp reduction in interest expenses and the initially slow response of compensation growth to the pickup in productivity growth. Compensation started to catch up with productivity gains during 1998, weakening the profit share. That trend is likely to continue to put downward pressure on profits through 2000.

Figure 3.
Corporate Book Profits



SOURCES: Congressional Budget Office; Department of Commerce, Bureau of Economic Analysis.

An increase in depreciation charges will also reduce book profits during the projection period. Corporations can deduct depreciation of plant and equipment from earnings in calculating their tax liability. The rapid rise in investment in recent years and the high level of investment throughout the projection period increase depreciation charges relative to earnings. Therefore, the profits on which corporate taxes are based tend to fall as a share of GDP.

The Budget Outlook

If current laws and policies remain unchanged and the economy performs as CBO assumes, the excess of total federal revenues over total federal outlays will grow from $120 billion in 1999 to $413 billion in 2009, CBO estimates (see Table 5). If those surpluses are realized, past borrowing from the public will be substantially repaid, and debt held by the public will fall from $3,720 billion at the end of 1998 to $865 billion at the end of 2009. As a portion of GDP, debt held by the public will plummet from 44.3 percent at the end of 1998 to 6.4 percent at the end of 2009.

Table 5.
The Budget Outlook Under Current Policies (By fiscal year)

	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
In Billions of Dollars												
Baseline Total Surplus[a]	69	120	161	193	246	247	266	286	334	364	385	413
On-Budget Deficit (-) or Surplus (Excluding Social Security and the Postal Service)[a]	-30	-4	14	38	82	75	85	92	129	146	157	178
Memorandum:												
Off-Budget Deficit (-) or Surplus												
Social Security	99	125	147	155	163	172	181	195	205	217	228	235
Postal Service	b	-1	b	b	1	0	0	0	0	0	0	0
Total	99	125	147	155	164	172	181	195	205	217	228	235
As a Percentage of Gross Domestic Product												
Baseline Total Surplus[a]	0.8	1.4	1.7	2.0	2.5	2.4	2.4	2.5	2.8	2.9	3.0	3.1
On-Budget Deficit (-) or Surplus (Excluding Social Security and the Postal Service)[a]	-0.4	c	0.2	0.4	0.8	0.7	0.8	0.8	1.1	1.2	1.2	1.3

SOURCE: Congressional Budget Office.

a. Assumes that discretionary spending will equal the statutory caps on such spending through 2002 and will grow at the rate of inflation thereafter.

b. Less than $500 million.

c. Less than 0.05 percent.

Revenue growth continues to be the engine that drives mounting estimates of the surplus. From 1994 through 1998, revenues grew by an average of 8.1 percent a year, compared with only 3.1 percent for outlays. The rise in revenues is expected to slow to 5.8 percent in 1999 and to drop further--to an average rate of 4.1 percent a year--from 2000 through 2009. However, annual growth in outlays is projected to remain in the 3 percent range through 2009 (assuming that the caps are honored through 2002 and that discretionary spending grows at the rate of inflation thereafter), thus boosting total budget surpluses.

Total government inflows and outflows include the Social Security trust funds (Old-Age and Survivors Insurance and Disability Insurance), which have their own earmarked sources of revenue. Income going into those funds currently exceeds outlays for benefits and program administration. The trust fund surpluses have, by law, been invested in interest-bearing government securities, and that interest is part of the funds' income. Those investments have in turn reduced the need to borrow from the public to finance other programs.

Excluding Social Security and the Postal Service (which are classified as off-budget), the remainder of the budget recorded a $30 billion deficit in 1998. That on-budget deficit is expected to decline to $4 billion this year. In 2000, CBO projects, the on-budget measure will be in surplus by $14 billion if discretionary spending does not exceed its statutory caps. However, if the Congress enacts appropriations for discretionary spending that CBO estimates will exceed the statutory caps on outlays, the on-budget surplus in 2000 could disappear (see Box 1). Under CBO's baseline assumptions, though, the on-budget surplus in 2009 ($178 billion) is projected to begin approaching the size of the off-budget surplus ($235 billion).

Box 1.
Will There Be an On-Budget Surplus in 2000?

The concurrent resolution on the budget for fiscal year 2000 (H. Con. Res. 68) assumes enactment of legislation that will reduce revenues starting in 2001. But it also provides for a reduction in revenues in 2000 that is contingent on the Congressional Budget Office's (CBO's) baseline projections in this report. Under section 211 of the resolution, if CBO projects an on-budget surplus in 2000 under current policies, the Chairmen of the House and Senate Budget Committees may adjust the budget resolution to allow a reduction in revenues in 2000 equal to CBO's estimate of the on-budget surplus.

CBO's baseline projections, which assume that discretionary outlays in 2000 will equal the statutory limits (or caps) on such spending, show an on-budget surplus of $14 billion in 2000. However, that projection may overstate the appropriate estimate of the surplus for purposes of section 211 for two reasons:

- A portion of off-budget spending in CBO's projections is treated as on-budget spending in the budget resolution, thereby making it harder to achieve an on-budget surplus.
- In enforcing compliance with the caps on discretionary spending, the House and Senate Budget Committees may use estimates that will allow appropriations to exceed the outlay caps under CBO's estimates.

CBO's baseline calculation of the on-budget surplus excludes about $3 billion in spending for administrative expenses of the Social Security Administration (SSA) because that spending is designated by statute as off-budget. However, since 1991, budget resolutions have treated SSA administrative expenses as on-budget because, according to the Office of Management and Budget's interpretation, they are subject to the caps on discretionary spending. If CBO's projections are made consistent with the budget resolution's treatment of those expenses, the projected on-budget surplus falls to $11 billion.

Both CBO's baseline projections and the budget resolution assume that discretionary spending in 2000 will equal the statutory caps. For purposes of enforcing the resolution, however, the budget committees have indicated that they may reduce CBO's estimate of discretionary outlays resulting from appropriation bills considered this year by about $10 billion for defense, $1 billion for transportation, and $3 billion for other nondefense programs. Thus, if Congressional estimates of enacted appropriations incorporate all of those potential adjustments, discretionary spending will be $14 billion higher than CBO assumed for 2000 in its current baseline projections. Those adjustments largely reflect the fact that the Administration's estimates of outlays from appropriations are significantly lower than CBO's estimates (see *An Analysis of the President's Budgetary Proposals for Fiscal Year 2000*, April 1999). Thus, that scorekeeping adjustment is not likely to lead to a sequestration of discretionary spending.

If all of those adjustments are made, the projected on-budget surplus of $14 billion in 2000 turns into a deficit of more than $3 billion.

Small departures from CBO's economic or technical assumptions could result in budgetary outcomes that are substantially different from the projections, even without changes in policy. For instance, if CBO's economic projections proved overly optimistic or if health care spending resumed its rapid growth, surpluses could be lower than anticipated. Of course, the economy could also be more robust than expected, and the factors that have dampened spending on Medicare and Medicaid could continue. Under those circumstances, the budget outlook would be even brighter than CBO now projects. In any case, results for any one year that differ by as much as $100 billion from current projections are entirely possible. (For an illustration of how different economic assumptions could affect the budget, see Appendix C of CBO's January 1999 report *The Economic and Budget Outlook: Fiscal Years 2000-2009*.)

Changes in the Projections Since April

The budget outlook has continued to improve since April, when CBO published its previous baseline projections. The total budget surplus for the current year is now anticipated to be $10 billion higher than the earlier estimate (see Table 6). Projected surpluses for the 2000-2009 period average $30 billion a year more than before. Most of the changes in projected surpluses can be attributed to CBO's updated economic forecast.

Table 6.
Changes in Baseline Surpluses Since April 1999 (By fiscal year, in billions of dollars)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
April Baseline Surplus[a]	111	133	156	212	213	239	263	309	338	358	383
Legislative Changes											
Revenues	b	b	b	b	b	b	b	b	b	b	b
Outlays											
Discretionary	4	7	2	1	1	1	1	1	1	1	1
Mandatory											
Medicaid	0	0	1	1	1	1	1	1	1	1	1
Debt service	b	b	1	1	1	1	1	1	2	2	2
Subtotal	4	8	4	2	3	3	3	3	3	4	4
Total[c]	-4	-8	-4	-2	-3	-3	-3	-3	-3	-4	-4
Economic Changes											
Revenues	14	33	36	30	21	11	2	-3	-5	-7	-7
Outlays											
Discretionary	0	0	0	0	-1	-1	-2	-2	-3	-4	-5
Mandatory											
Social Security	0	-1	-2	-2	-3	-3	-4	-4	-5	-5	-6
Other COLA programs	b	b	-1	-1	-1	-2	-2	-2	-2	-3	-3
Unemployment insurance	0	-1	-1	-1	b	b	0	0	0	0	0
Net interest (Rate effects)	b	5	7	3	2	1	1	b	b	b	b
Debt service	b	-2	-3	-5	-7	-8	-10	-10	-11	-12	-13
Other	b	-1	-1	-1	-1	-1	-2	-2	-2	-2	-2
Subtotal	-1	b	b	-7	-11	-14	-18	-20	-23	-26	-29
Total[c]	15	33	37	37	33	26	20	18	18	19	22
Technical Changes											

Revenues	-8	2	3	1	4	3	6	6	6	6	5
Outlays											
Discretionary	-4	b	b	b	b	b	b	b	b	b	b
Mandatory											
Medicare	-4	-3	-1	-1	-1	-1	-1	-1	-1	-1	-1
Medicaid	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	b
Agriculture programs	1	2	1	1	b	b	b	b	b	b	b
Debt service	b	b	b	b	b	-1	-1	-1	-2	-2	-3
Other	b	1	b	2	2	1	2	-1	-2	-2	-3
Subtotal	-6	-2	-1	1	b	-2	-1	-4	-5	-6	-7
Total[c]	-1	3	4	b	5	5	7	10	11	12	13
Total Changes											
Revenues	7	35	40	30	26	14	8	4	1	-1	-2
Outlays	-3	7	3	-4	-9	-13	-16	-21	-25	-28	-32
Total	10	28	37	34	35	28	24	25	26	27	31
July Baseline Surplus[a]	120	161	193	246	247	266	286	334	364	385	413

SOURCE: Congressional Budget Office.

NOTE: Revenue gains are shown with a positive sign because they increase the surplus. COLA = cost-of-living adjustment.

a. The baseline assumes that discretionary spending will equal the statutory caps on such spending through 2002 and will grow at the rate of inflation thereafter.

b. Less than $500 million.

c. Includes changes in both revenues and outlays. The figure shown is the effect on the surplus. Increases in the surplus are shown as positive.

Recent Legislation. The only legislation enacted since April that will have a significant impact on the budget is the 1999 Emergency Supplemental Appropriations Act (P.L. 106-31). That act designated almost $15 billion in emergency budget authority, which is not subject to the statutory spending caps. It provided funds for military operations in Kosovo and the Middle East, refugee relief in those and other regions, assistance to Jordan and Central America, domestic and international relief for natural disasters (principally the tornadoes in Oklahoma and Kansas and Hurricane Mitch in Central America), and for other purposes.

The act provided close to $13 billion in appropriations designated as emergencies for fiscal year 1999 and nearly $2 billion for 2000. Of the amount provided for 1999, roughly three-quarters is for defense programs. Almost all of the amount for 2000 is for military pay and retirement.

As a result of the additional appropriations, outlays are expected to be $4 billion higher this year, $7 billion higher in 2000, and higher by smaller amounts through 2009. Bumping up the level of outlays permitted under the statutory cap in 2002 causes CBO's projection of discretionary spending in 2003 through 2009 to be $1 billion higher annually. CBO's baseline assumes that total discretionary spending grows at the rate of inflation after the caps are lifted in 2002; the higher level of outlays now projected for 2002 raises the base from which future totals are computed.

One mandatory program was also affected by the Emergency Supplemental Appropriations Act. The act prohibited the federal government from recouping any money for Medicaid from the settlement of states' lawsuits against tobacco companies. CBO had previously assumed that the Medicaid program would be able to collect about $1 billion a year after 2000.

Economic Reestimates. Revisions that can be traced to changes in the macroeconomic forecast increase CBO's projection of the surplus for 1999 by $15 billion. Those revisions rise to $37 billion for 2001 and 2002 before diminishing to about $20 billion annually for the latter part of the decade.

Changes to the revenue forecast account for most of the economic differences in the first half of the projection period. Projected revenues have been increased by $14 billion for 1999 and by more than twice that much for each year from 2000 through 2002. Most of those increases result because GDP is projected to be higher than in CBO's previous forecast. The effect of the economic projections on revenues diminishes and then turns negative in 2006 because taxable personal income is estimated to grow more slowly than in the January projection. In addition, book profits (the base of the corporate income tax) are projected to be lower beginning in 2002 than CBO estimated in January.

On the outlay side of the budget, projections of lower inflation reduce estimates of the future costs of a variety of programs whose cost-of-living adjustments (COLAs) are tied to the consumer price index. Reduced estimates of the COLA for Social Security lower projected spending for that program by $6 billion in 2009. Other programs--such as civilian retirement, military retirement, and Supplemental Security Income--face reduced costs of up to $3 billion per year as a result of lower projected inflation. CBO's lower projections for the CPI-U (the CPI for all urban consumers) also result in lower inflation adjustments for discretionary spending after the caps expire.

The recent strength of the job market has been reflected in a low rate of unemployment (CBO's estimate of the civilian unemployment rate for calendar year 1999 is 4.2 percent). Although CBO assumes that the unemployment rate will increase gradually over time, its estimates for the next few years are considerably lower than those of January. Such a reduction brings projected spending on unemployment insurance down by $1 billion a year for 2000 through 2002.

One of the few exceptions to the trend of lower outlay projections is the economic reestimate for net interest. Higher projected interest rates boost net interest (and therefore reduce surpluses) by $5 billion in 2000 and $7 billion in 2001. The effect of higher rates trails off by 2006. By that time, interest savings resulting from lower borrowing needs are projected to increase the surplus by more than $10 billion a year.

Technical Reestimates. Technical revisions are changes that are not ascribed to either new legislation or revisions in the macroeconomic forecast. The wide-ranging factors that account for technical changes lead to increases of a few billion dollars each year in the projected surpluses for 2000 through 2005. By 2009, technical reestimates add $13 billion to the surplus.

Technical changes to revenues stem primarily from data on revenue collections through May. Since no "April surprise" occurred this year (unlike the past couple of years, revenues this April were very close to what CBO expected), such changes are relatively small. Aside from 1999, technical reestimates to revenues increase the surplus by amounts up to $6 billion a year. Among the various categories of revenues, technical changes to individual income tax collections are up and changes to corporate tax revenues are down. Those two categories largely offset one another, however.

CBO's Medicare projections reflect lower-than-expected outlays through the first eight months of 1999. Medicare outlays to date are actually lower than they were for the same period last year. Lower payments for home health services and a drop in the case-mix index (a measure of the relative costliness of the cases treated in hospitals paid under the prospective payment system) explain most of the shortfall in Medicare spending so far this year. Some of the drop in home health spending stems from longer payment lags under sequential billing--a new method of processing claims in which payment is made only if all prior claims have been processed. Medicare will suspend that billing process in July, which should increase spending during the last quarter of the fiscal year. In addition, the use of home health services seems to have dropped substantially, probably as a result of both antifraud activities and an unexpectedly cautious response by home health agencies to the per-beneficiary limit under the interim payment system. Medicare will replace the interim payment system for home health services with a prospective payment system in 2001. That system will remove much of the uncertainty about payments that has contributed to the current apparent drop in use of services, so spending for home health services is expected to rebound in 2001 and later years.

CBO has also raised its projections of spending for farm price and income supports by $1 billion for 1999 and $2 billion for 2000. Spending is estimated to total $16 billion in 1999 (including most of the $6 billion in emergency farm spending from the Omnibus Consolidated and Emergency Supplemental Appropriations Act for 1999) and $10 billion in 2000. Farm prices for many supported commodities have continued to decline from the low levels CBO projected last winter; they are now at least as low as in the 1980s and early 1990s. The farm prices of corn and soybeans, for example, are the lowest since 1987 and 1986, respectively. If next year's soybean price is as low as currently projected, it will be the lowest since 1972. For those and other major crops, lower-than-expected prices are triggering loan deficiency payments and marketing loan costs (ways of assisting farmers during periods of low market prices) that were not expected under the Federal Agricultural Improvement and Reform Act of 1996. Those conditions result from consecutive years of plentiful crops coinciding with weak global demand. Over the longer run, demand for U.S. agricultural products is expected to improve, and spending on farm price supports is projected to decline to less than $5 billion by 2003.

Revenue and Spending Projections

CBO projects that revenues will reach a post-World War II high of 20.6 percent of GDP this year. Without any changes in policy, revenues are expected to remain at that level next year before falling slowly to a long-run level of 20.1 percent of GDP by 2004 (see Table 7).

Table 7.
CBO Baseline Budget Projections, Assuming Compliance with the Discretionary Spending Caps (By fiscal year)

	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
						In Billions of Dollars						
Revenues												
Individual income	829	887	930	958	991	1,024	1,065	1,113	1,166	1,221	1,281	1,346
Corporate income	189	178	177	181	189	195	202	210	219	227	235	241
Social insurance	572	607	646	671	696	722	749	786	819	855	889	925
Other	133	149	153	160	169	175	181	186	193	198	205	213
Total	1,722	1,821	1,905	1,970	2,045	2,116	2,198	2,296	2,396	2,501	2,609	2,725
On-budget	1,306	1,377	1,431	1,477	1,533	1,585	1,646	1,717	1,793	1,871	1,953	2,042

Off-budget	416	444	474	493	511	532	553	579	603	630	656	683
Outlays												
Discretionary spending	555	574	580	575	569	583	598	613	628	644	660	677
Mandatory spending	939	977	1,022	1,077	1,132	1,200	1,266	1,350	1,409	1,493	1,590	1,689
Offsetting receipts	-84	-79	-80	-86	-98	-93	-96	-101	-106	-112	-118	-125
Net interest	243	229	222	212	194	179	164	148	131	112	92	71
Total	1,653	1,701	1,744	1,777	1,798	1,869	1,932	2,009	2,062	2,137	2,224	2,312
On-budget	1,336	1,381	1,417	1,440	1,451	1,510	1,561	1,625	1,664	1,725	1,796	1,864
Off-budget	317	320	327	337	347	359	371	384	398	412	428	447
Deficit (-) or Surplus	69	120	161	193	246	247	266	286	334	364	385	413
On-budget	-30	-4	14	38	82	75	85	92	129	146	157	178
Off-budget	99	125	147	155	164	172	181	195	205	217	228	235
Debt Held by the Public	3,720	3,618	3,473	3,297	3,066	2,835	2,584	2,312	1,992	1,640	1,267	865

As a Percentage of Gross Domestic Product

Revenues												
Individual income	9.9	10.0	10.0	9.9	9.9	9.8	9.8	9.8	9.8	9.8	9.9	9.9
Corporate income	2.2	2.0	1.9	1.9	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.8
Social insurance	6.8	6.9	7.0	7.0	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.8
Other	1.6	1.7	1.6	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.6	1.6
Total	20.5	20.6	20.6	20.4	20.3	20.2	20.1	20.2	20.2	20.1	20.1	20.1
On-budget	15.5	15.6	15.5	15.3	15.3	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Off-budget	4.9	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.0
Outlays												
Discretionary spending	6.6	6.5	6.3	6.0	5.7	5.6	5.5	5.4	5.3	5.2	5.1	5.0
Mandatory spending	11.2	11.0	11.0	11.2	11.3	11.5	11.6	11.9	11.9	12.0	12.3	12.5
Offsetting receipts	-1.0	-0.9	-0.9	-0.9	-1.0	-0.9	-0.9	-0.9	-0.9	-0.9	-0.9	-0.9
Net interest	2.9	2.6	2.4	2.2	1.9	1.7	1.5	1.3	1.1	0.9	0.7	0.5
Total	19.7	19.2	18.8	18.4	17.9	17.8	17.7	17.7	17.3	17.2	17.1	17.1
On-budget	15.9	15.6	15.3	14.9	14.4	14.4	14.3	14.3	14.0	13.9	13.8	13.8
Off-budget	3.8	3.6	3.5	3.5	3.5	3.4	3.4	3.4	3.3	3.3	3.3	3.3
Deficit (-) or Surplus	0.8	1.4	1.7	2.0	2.5	2.4	2.4	2.5	2.8	2.9	3.0	3.1
On-budget	-0.4	a	0.2	0.4	0.8	0.7	0.8	0.8	1.1	1.2	1.2	1.3
Off-budget	1.2	1.4	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.7
Debt Held by the Public	44.3	40.9	37.5	34.2	30.5	27.1	23.7	20.3	16.8	13.2	9.8	6.4

Memorandum:												
Gross Domestic Product (Billions of dollars)	8,404	8,851	9,259	9,652	10,055	10,476	10,913	11,385	11,887	12,418	12,972	13,547

SOURCE: Congressional Budget Office.

a. Less than 0.05 percent.

Individual income tax receipts--bolstered primarily by high capital gains realizations and increases in the effective tax rate--have been the main source of the rapid growth in revenues as a percentage of GDP. A sharp rise in stock prices partly explains the higher realizations of capital gains. And especially rapid growth in income among high-income taxpayers, who are taxed at high marginal rates, has boosted the effective tax rate. CBO expects total revenues to grow by 5.8 percent this year but does not expect them to continue increasing more rapidly than overall growth of GDP.

On the other side of the ledger, outlays are projected to rise more slowly than revenues, increasing by an average of 3.2 percent annually from 2000 through 2009. In dollar terms, total outlays will grow from $1,701 billion in 1999 to $2,312 billion in 2009, CBO estimates. As a percentage of GDP, however, outlays are projected to decline throughout the period--from 19.2 percent of GDP in 1999 to 17.1 percent in 2009.

Discretionary spending is currently restrained by an assortment of caps through 2002 (see Table 8). If left intact, those caps will bring total discretionary spending down from $574 billion in 1999 to $569 billion in 2002. CBO assumes that after 2002, discretionary spending will grow at the rate of inflation. Even so, such spending is projected to decline from 6.5 percent of GDP in 1999 to 5.0 percent in 2009.

Table 8.
CBO Baseline Projections of Discretionary Outlays, Assuming Compliance with the Spending Caps (By fiscal year, in billions of dollars)

	Actual 1998	1999	2000	2001	2002
Defense	270	275	a	a	a
Domestic and International	257	269	a	a	a
Violent Crime Reduction	4	5	6	a	a
Highways	19	21	25	26	27
Mass Transit	4	4	4	5	5
Overall Discretionary	n.a.	n.a.	546	544	537
Total	555	574	580	575	569

SOURCE: Congressional Budget Office.

NOTES: The caps reflect discretionary spending limits as specified by the Office of Management and Budget in the sequestration preview report included in the President's budget, adjusted for CBO's estimate of contingent emergency releases that the President has not yet designated. The caps have also been adjusted for emergency spending enacted since January.

n.a. = not applicable.

a. After the specific cap expires, spending from programs in that category is shown in the "Overall Discretionary" category.

Spending for entitlements and other mandatory programs, by far the largest category of spending, is expected to total $977 billion this year. Three programs--Medicare, Medicaid, and Social Security--account for roughly three-quarters of that total (see Table 9). Medicare and Medicaid have consistently been among the fastest-growing programs in the past decade. In 1999, however, outlays for Medicare are expected to fall by $1 billion. The factors that are restraining the growth of Medicare spending will be played out in the near future, and growth is projected to rebound to an average rate of nearly 8 percent a year. Partly as a result, CBO projects that total mandatory spending will increase from 11.0 percent of GDP in 1999 to 12.5 percent in 2009.

Table 9.
CBO Baseline Projections of Mandatory Spending (By fiscal year, in billions of dollars)

	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Means-Tested Programs												
Medicaid	101	107	115	124	134	146	159	173	188	205	224	244
State Children's Health Insurance	a	1	2	3	4	4	4	4	4	5	5	5
Food Stamps	20	19	20	21	22	23	23	24	25	25	26	27
Supplemental Security Income	27	28	29	31	33	35	36	41	40	39	45	47

Family Support[b]	18	20	21	21	22	22	23	24	25	26	27	27
Veterans' Pensions	3	3	3	3	3	3	3	4	4	3	4	4
Child Nutrition	9	9	9	10	10	11	11	12	13	13	14	14
Earned Income Tax Credit[c]	23	26	27	27	28	28	29	30	30	31	31	32
Student Loans	3	3	5	5	5	5	5	5	5	5	5	6
Foster Care	4	5	5	6	6	7	7	8	8	9	10	10
Total	209	222	237	252	268	284	302	325	342	361	389	416
Non-Means-Tested Programs												
Social Security	376	387	402	420	440	461	483	507	532	559	588	621
Medicare	211	210	225	243	253	277	298	328	342	377	408	442
Subtotal	587	597	627	663	694	738	781	835	875	936	997	1,063
Other Retirement and Disability												
Federal civilian[d]	47	49	50	52	55	57	60	63	66	69	72	75
Military	31	32	33	34	35	36	37	38	39	40	41	42
Other	4	5	5	5	5	5	5	5	5	5	5	5
Subtotal	83	86	88	91	94	98	102	106	110	114	118	122
Unemployment Compensation	20	21	22	24	26	28	29	30	31	32	34	35
Deposit Insurance	-4	-6	-2	-1	a	a	1	1	-1	-1	-1	-1
Other Programs												
Veterans' benefits[e]	21	21	22	23	23	24	25	27	26	24	27	27
Farm price and income supports	9	17	11	8	6	5	5	5	5	5	5	5
Social services	5	5	5	5	5	5	5	5	5	5	5	5
Credit reform liquidating accounts	-8	-7	-7	-7	-7	-7	-8	-7	-8	-8	-8	-8
Universal Service Fund	2	4	6	8	13	14	14	14	14	14	14	14
Other	17	19	13	12	11	12	12	11	11	11	12	12
Subtotal	45	58	49	47	51	52	51	54	52	51	54	55
Total	730	755	784	825	864	916	964	1,025	1,067	1,132	1,201	1,273
Total												
All Mandatory Spending	939	977	1,022	1,077	1,132	1,200	1,266	1,350	1,409	1,493	1,590	1,689

SOURCE: Congressional Budget Office.

NOTE: Spending for the benefit programs shown above generally excludes administrative costs, which are discretionary. Spending for Medicare also excludes premiums, which are considered offsetting receipts.

a. Less than $500 million.

b. Includes Temporary Assistance for Needy Families, Family Support, Aid to Families with Dependent Children, Job Opportunities and Basic Skills, Contingency Fund for State Welfare Programs, Child Care Entitlements to States, and Children's Research and Technical Assistance.

c. Includes outlays from the child credit enacted in the Taxpayer Relief Act of 1997.

d. Includes Civil Service, Foreign Service, Coast Guard, other retirement programs, and annuitants' health benefits.

e. Includes veterans' compensation, readjustment benefits, life insurance, and housing programs.

Net interest, which was the fastest-growing category of spending in the 1980s, is now expected to decline substantially. As projected surpluses reduce the stock of debt held by the public by nearly $2.8 trillion, net interest costs will drop from $229 billion (2.6 percent of GDP) in 1999 to $71 billion (0.5 percent of GDP) in 2009 (see Table 10).

Table 10.
CBO Baseline Projections of Interest Costs and Federal Debt (By fiscal year)

	Actual 1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Net Interest Outlays (Billions of dollars)												
Interest on Public Debt (Gross interest)[a]	364	356	358	358	350	345	342	338	333	328	323	316
Interest Received by Trust Funds												
Social Security	-47	-53	-59	-67	-74	-82	-91	-100	-110	-121	-132	-144
Other trust funds[b]	-67	-68	-70	-73	-74	-76	-79	-81	-84	-87	-89	-92
Subtotal	-114	-120	-129	-140	-148	-159	-170	-182	-194	-208	-222	-236
Other Interest[c]	-7	-7	-6	-7	-7	-7	-8	-8	-8	-8	-8	-9
Total	243	229	222	212	194	179	164	148	131	112	92	71
Federal Debt at the End of the Year (Billions of dollars)												
Gross Federal Debt	5,479	5,582	5,664	5,721	5,737	5,760	5,770	5,770	5,732	5,675	5,600	5,500
Debt Held by Government Accounts												
Social Security	730	856	1,003	1,157	1,321	1,493	1,675	1,869	2,075	2,292	2,520	2,755
Other accounts[b]	1,029	1,107	1,188	1,267	1,350	1,431	1,510	1,589	1,666	1,743	1,813	1,880
Subtotal	1,759	1,963	2,190	2,425	2,670	2,925	3,185	3,458	3,741	4,035	4,333	4,635
Debt Held by the Public	3,720	3,618	3,473	3,297	3,066	2,835	2,584	2,312	1,992	1,640	1,267	865
Debt Subject to Limit[d]	5,439	5,543	5,626	5,684	5,700	5,724	5,734	5,736	5,699	5,643	5,568	5,469
Federal Debt as a Percentage of Gross Domestic Product												
Debt Held by the Public	44.3	40.9	37.5	34.2	30.5	27.1	23.7	20.3	16.8	13.2	9.8	6.4

SOURCE: Congressional Budget Office.

NOTE: Projections of interest and debt assume that discretionary spending will equal the statutory caps on such spending through 2002 and will grow at the rate of inflation thereafter.

a. Excludes interest costs of debt issued by agencies other than the Treasury (primarily the Tennessee Valley Authority).

b. Mainly Civil Service Retirement, Military Retirement, Medicare, unemployment insurance, and the Airport and Airway Trust Fund.

c. Mainly interest on loans to the public.

d. Differs from the gross federal debt primarily because most debt issued by agencies other than the Treasury is excluded from the debt limit. The current debt limit is $5,950 billion.

In addition to debt issued to the public, the Department of the Treasury issues securities to government trust funds and other government accounts. Debt subject to limit basically measures the combination of debt held by the public and debt held internally by government accounts. Because inflows to major trust funds exceed outlays for benefits and other costs, debt held by government accounts is projected to increase from $2 trillion in 1999 to $4.6 trillion in 2009. At the same time, however, debt held by the public is projected to decrease from $3.6 trillion to $0.9 trillion. Therefore, on net, debt subject to limit is projected to finish 2009 slightly below its current level and is not expected to breach its statutory limit of $5.95 trillion in the next 10 years.

Conclusion

Overall, the outlook for the budget looks good through 2009. CBO's current projections are slightly better than those reported in April, and its economic forecast anticipates healthy growth in the near term. However, demographic tensions loom in the not-so-distant future. After 2010, the retirement of the baby-boom generation will pick up steam, bringing with it a greater demand for Social Security, Medicare, and Medicaid benefits. Budgetary pressures caused by increased participation in such programs can easily reverse the favorable fiscal forces that are operating today.

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1. See the baseline projections published in Appendix A of *An Analysis of the President's Budgetary Proposals for Fiscal Year 2000* (April 1999). The economic assumptions underlying those projections were prepared in December and published in January in Chapter 1 of *The Economic and Budget Outlook: Fiscal Years 2000-2009.*

2. An expanded version of the economic outlook is available on CBO's World Wide Web site (www.cbo.gov).

3. CBO's forecast and the discussion above were produced before the June 29-30 meeting of the Federal Open Market Committee.

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-070

Responses by Carl G. K. Weaver to
Request for Information by
Public Service Commission

20. Explain whether Dr. Weaver believes that local distribution companies are perceived by investors as having higher risks because of deregulation.

Answer:

Regulation does provide a "safety net" for regulated companies and deregulation will increase the risk exposure of the local distribution companies. This is why it is important to carefully select companies to use to obtain data and to use data obtained from the securities market in performing the analysis. This data will reflect investor perceptions regarding the risk of the regulated companies.