CASE NUMBER:

99-070

51

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 51, a - b
Witness: Gary Smith

Data Request:

51. Refer to Mr. Smith's testimony at page 25, lines 19-22.

a. If different from the answer to the immediately preceding question, class revenues and class cost responsibilities contained in Mr. Peterson's study, and any other specific contents of Mr. Petersen's study, that were relied upon as a guide for the realignment of class revenue responsibilities.

b. Please quantify the amount of class revenue responsibilities the Company proposes to effectuate through its proposals in this case.

Response:

a. The embedded cost of service study utilized as a guide in included as FR 10(9)(v) of the Company's application. However, we were cognizant that Mr. Petersen's study was based on costs and revenues in FY 1998, weather normalized. As a general guide for customer class revenue responsibilities, the percent rate of return on rate base, Page 1 of 19, line 21. Page 19 of 19, line 18 was reviewed for guidance on monthly customer charge levels.

b. Please refer to PSC DR # 2-Item 71, proposed rates, for the class revenue responsibilities proposed.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 52
Witness: Gary Smith

Data Request:

52. Please explain the circumstances under which the Company would extend its mains and incur other costs in order to connect a gas cooking only customer. Have there been any such hook-ups since the Company's last rate case? If so, how many?

Response:

I am not aware that any such customer request for a hook-up for gas cooking only has been made to the Company. We have no records that would indicate any customer additions of this nature.

If such a request were made for the Company to extend its mains to connect a gas cooking only customer, Western would, as a matter of policy require a deposit for said main extension. The Company's tariff, at P.S.C. No. 20, Sheet No. 82, section 28 (a) (3) sets forth the condition that "potential *consumption* and revenue will be of such amount and permanence as to warrant the capital expenditures involved to make the investment economically feasible." *(emphasis added)*

The Company's current expectation is that a residential customer meets the necessary consumption criteria if it's primary heating system is to be fueled by natural gas.

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 53
Witness: Gary Smith

Data Request:

53. Same question as above, but this time dealing with hooking up a gas cooking only customer from an existing main.

Response:

I am not aware that any such customer request for a hook-up for gas cooling only has been made to the Company. We have no records that would indicate any customer additions of this nature, either from an existing main, or where an extension of the Company's main would be required (refer to this Initial AG Data Request, Item 52).

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 54
Witness: Smith

Data Request:

Please provide that portion of proposed tariff that details Western's proposed Margin Loss Recovery Rider.

Response:

See Western's Application, Volume 1, Tab 6, page 29L.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 55
Witness: Gary Smith

Data Request:

55. In Mr. Smith's opinion, would the statement "... any contribution made by a major customer to the Company's fixed costs is better than none ..." be true of only major customers? Or of all customers? Explain.

Response:

No. Contributions toward fixed costs from any customer are of importance to both the Company and other ratepayers. However, Western's major industrial customers are of more critical concern to the financial well-being of the Company and its other customers because the size of their load and, typically, competitive options.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 56
Witness: Gary Smith

Data Request:

56. Refer to Mr. Smith's testimony at page 30, lines 28-30. Please provide the referenced incremental costs, both conceptually and quantitatively, for Western.

Response:

The incremental costs, for an existing customer, would include variable/avoidable service costs. Such costs could include gas costs, lost & unaccounted for provisions, odorant, regulatory assessments, the depreciation expense on customer service facilities, return, income taxes, and estimated costs of meter reading, maintenance and billing.

As stated in Mr. Smith's testimony at page 30, lines19-24, Western submits an Analysis of Contribution to Fixed Cost in each case of securing the Commission's acceptance of a special contract. This Analysis includes the pricing terms of the proposed agreement, less the applicable incremental costs set forth above, to determine the customers fixed cost contribution.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 57, a - b
Witness: Gary Smith

Data Request:

57. Refer to Mr. Smith's testimony at page 31, lines 4-5.

a. Please provide Mr. Smith's opinion as to what constitutes an over assignment of fixed joint and common costs to the industrial class.

b. Is there such an over assignment in this case? If so, please explain why, and the amount of such over assignment, in Mr. Smith's opinion.

Response:

a. The specific case in the referenced testimony addresses a bypass customer's tariff rates, designed on a class-basis, uniquely situated avoid Western's charges by installing bypass facilities. In all such cases, Western seeks to maximize its retained revenue. An analysis of contribution to fixed costs is submitted to the Commission when requesting their approval of any discounts from tariff.

b. No. Western's proposed rate structures provide fair, just and reasonable prices.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 58
Witness: Smith

Data Request:

Please provide the Atmos companies Margin Loss Recovery tariff provisions in their Tennessee, Georgia and South Carolina's operations.

Response:

See attached Tennesse, Georgia and South Carolina tariff pages. Please note that South Carolina Margin Loss Recovery Mechanism is a component of the Purchased Gas Adjustment – see Item M under the Balancing Adjustment.

MARGIN LOSS RECOVERY RIDER

Intent and Applicability

This Margin Loss Recovery Rider is intended to authorize the Company to recover not more than ninety percent (90%) of the gross profit margin losses that result from rates negotiated under the provisions of Rate Schedule 291 or from customers who transfer from Rate Schedule 240 to optional service.

Determination of Gross Profit Margin Losses

The gross profit margin loss shall be calculated as ninety percent (90%) of the difference between the normally applicable Rate Margin as determined in the Company's most recent rate case order of the Tennessee Regulatory Authority and the Actual Negotiated Rate Margin and/or the margin loss incurred from the transfer of customers from Rate Schedule 240 to optional service. Any amount of gross profit margin losses shall be recovered from the commodity component of gas costs as determined under the presently effective Purchased Gas Adjustment Rider.

Filing With the Tennessee Regulatory Authority

Each gross profit margin loss accounting/recovery period shall correspond with the Company's Actual Cost Adjustment period.

NEGOTIATED GAS SERVICE

RATE SCHEDULE 891

Applicability

Gas Service under this rate schedule is available to those customers having alternate fuel capability at the Company's discretion. This rate schedule is designed to permit the Company to meet alternate fuel and/or gas to gas competition. Service under this rate schedule shall be fully optional and subject to curtailment prior to optional customers on regular Rate Schedule 850.

The intent of this rate schedule is to provide the Company flexibility to sell gas at negotiated rates when the otherwise applicable tariff rates are non-competitive. The Company will make every effort to maximize recovery of base margins and fixed components of the purchased gas adjustment. In the event this rate schedule is implemented, the revenue deficiency will be added to the balancing adjustment of the Purchased Gas Adjustment Rider approved by the Georgia Public Service Commission.

Rate

Customer Charge

A monthly customer charge of $100.00 per meter is payable regardless of the usage of gas.

Demand Charge

The monthly demand charge shall be the daily firm demand quantity contracted for by the customer multiplied by $.456 Ccf.

Commodity Charge

The rates charged under this rate schedule shall be negotiated monthly on a per customer basis. The Company may require supporting documents from the end-user certifying that the cost of available alternate supply is less than the otherwise applicable tariff rate. The maximum charge shall not exceed the sales rate schedule under which the customer would otherwise be charged. The minimum charge shall not be less than the commodity cost of gas plus 1% per Ccf.

NEGOTIATED GAS SERVICE

RATE SCHEDULE 891 (Continued)

Rate - continued

Minimum Bill

The monthly bill shall be the customer charge and the demand charge, if any.

Payment

Each monthly bill for service is due and payable on the date it is issued. A charge of one and one-half percent (1.5%) may be added to the amount of any balance in excess of $20 remaining unpaid at the close of the first business day after fifteen (15) days following such date of issue.

All applicable taxes shall be levied against sales under this rate schedule.

PURCHASED GAS ADJUSTMENT RIDER

I. Provisions for Adjustment

A. The rates per therm of gas set forth in all of the Rate Schedules of United Cities Gas Company (the "Company") shall be increased or decreased by an amount hereinafter described, which amount is called the "Purchased Gas Adjustment" ("PGA").

B. The cost of purchased gas as sued in determination of the PGA shall include, but not be limited to:

1. Cost of natural gas purchased from producers, associations, marketers, brokers, pipeline or transmission companies, and distribution companies whether or not regulated by the FERC.

2. Cost of liquefied natural gas (LNG) and vaporized LNG.

3. Cost of liquefied petroleum gas (LPG).

4. Cost of substitute natural gas (SNG).

5. Cost of other hydrocarbons used as feedstock for production of substitute natural gas.

6. Cost of contractual storage and transportation costs related to 1 through 5 above.

II. Definitions

"Computation Period" -- the twelve (12) month period utilized to compute the cost of purchased gas. Such period shall be the twelve month period ending on the last day of the month which is no more than 62 days prior to the filing date of such adjustment.

"Billing Determinants" -- the quantities of gas demand or other fixed maximums for which the Company has contracted with suppliers as of the end of the computation period; and the volumes of gas taken by the Company from suppliers during the computation period.

"Demand Cost" -- either (1) the product resulting from multiplying (a) the demand billing determinants by (b) the demand rate(s) which will be in effect when the adjustment is applied to customer bills, or (2) the expected annual dollar costs of fixed charges.

"Commodity Cost" -- the product resulting from multiplying (a) the sum of the volumes of gas taken by the Company during the computation period by (b) the commodity rate(s) which will be in effect when the adjustment is applied to customer bills.

"Storage Demand Cost" -- the product resulting from multiplying (a) the storage billing determinants by (b) the supplier demand or fixed charge rate which will be in effect when the adjustment is applied to customer bills.

"Storage Commodity Cost" -- the product (a) of volumes withdrawn from storage during the computation period multiplied by (b) the applicable supplier rate used in computing the "commodity cost" above.

III. Computation of Purchased Gas Adjustment

The PGA shall be computed to the nearest one-hundredth cent per therm in the following manner:

The PGA shall be the sum of the Commodity Cost, Storage Demand Cost, Storage Commodity Cost, and multiplied by a tax factor of 1.00123. The demand cost shall be apportioned to firm and optional Rate Schedules in a manner consistent with the level of secured service provided under such Rate Schedules.

The above is stated algebraically below:

$$\text{Firm PGA} = \left[\frac{Df}{Sf} \quad \frac{C + Sd + SC}{St} \right] 1.00123$$

$$\text{Optional PGA} = \left[\frac{Do}{So} \quad \frac{C + Sd + SC}{St} \right] 1.00123$$

Where

Df	=	Firm Demand Cost
Do	=	Optional Demand Cost
C	=	Commodity Cost
Sd	=	Storage Demand Cost
Sc	=	Storage Commodity Cost
St	=	Total Sales
Sf	=	Firm Sales
So	=	Optional Sales

The resulting Purchased Gas Adjustment so computed shall be applied to the billings for gas service effective with the date of a change in supplier cost.

IV. Treatment of Surcharges

Any gas cost related surcharge to the Company by any supplier shall be added to the commodity cost, after the recovery of such surcharges are approved by the South Carolina Public Service Commission.

V. Balancing Adjustment

A. Commencing with the period ending June 30, 1988, and each ensuing twelve month period thereafter, the Company shall calculate, in accordance with the formula set forth below, the amount by which the revenues recovered by the Company under this Rider were greater or less than the cost of the gas sold by the Company during such period.

This amount, hereinafter referred to as the "Balancing Adjustment," shall if positive (i.e., an over recovery) be subtracted from, or, if negative (i.e., an under recovery) be added to, the PGA Cost to be recovered by the Company under this Rider during the following twelve month period. The Balancing Adjustment shall be applied to customer billings effective with Cycle One of November of each year.

B. Balancing Adjustment Formula:

$$Bf = \frac{R - (D + B1)}{Sf} \qquad \frac{R-(P-IN+W+M+B1)}{St}$$

$$Bo = \frac{R - (D + B1)}{So} \qquad \frac{R-(P-IN+W+M+B1)}{St}$$

Where:

Bf = Firm Balancing Adjustment for the current twelve-month period.

Bo = Optional Balancing Adjustment for the current twelve-month period.

B1 = Residual of the Previous Balancing Adjustment, as of October 31, with a segregated Balancing Adjustment for Factor "D".

R = Revenues recovered under this Rider during the current twelve-month period. The revenues generated by Factors "Df" and "Do", as defined in Section III of this Rider, shall be separately stated.

D = Demand costs apportioned to firm or optional Rate Schedules, as prescribed in Section III of this Rider.

P = Costs of all gas purchased from Suppliers during the current twelve-month period, excluding costs contained in Factor "D".

IN = Costs of purchased gas injected into storage during the current twelve-month period.

W = Inventory costs of storage gas, Liquefied Natural Gas (LNG) and Liquefied Petroleum Gas (LPG) withdrawn from storage during the current twelve-month period.

M = Margin losses incurred from sales under Rate Schedule 791 to the extent that such losses do not exceed the savings realized from the spot market gas entering the system during the same period that the margin losses were incurred. Margin losses do not include revenue losses incurred when no sales are made to an industrial customer.

St = The quantity of gas expressed in number of therms billed to all customers of the Company during the computation period.

Sf = The quantity of gas expressed in number of therms billed to firm customers of the Company during the computation period.

So = The quantity of gas expressed in number of therms billed to optional customers of the Company during the computation period.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 59
Witness: Gary Smith

Data Request:

59. Refer to Mr. Smith's testimony at page 31, line 18-23. How would the margin from a new industrial customer affect a margin loss adjustment? Explain.

Response:

The proposed margin loss adjustment would not be affected by new industrial customer additions. Nor would the margin loss adjustment be affected by the loss of industrial customers to closings.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 60, a - b
Witness: Gary Smith

Data Request:

60. Refer to Mr. Smith's testimony at page 35, lines 6-13.

a. Please indicate Mr. Smith's opinion as to the dollar amount for a typical residential heating customer that results in the referenced harm to the customer.

b. Please provide the dollar amount for a typical residential heating customer that results in the referenced substantial harm.

Response:

a&b. The term "harm" in the testimony referenced above, at page 35, line 7, refers to the concept of equity. The dollar amount, whether $0.01 or $200, does not alter the inequity of gas payments above "normalized" levels. "Substantial harm" refers to the repeated occurrence of customer gas payments above "normalized levels" and leads to greater inequity. This inequity is avoidable through a Weather Normalization Adjustment, such as proposed by Western.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 61
Witness: Smith

Data Request:

Please provide Western's affiliate, United Cites Gas Company, Tennessee and Georgia's WNA tariff.

Response:

As a point of information, none of the five LDC business units of Atmos are "affiliates". Each is an unincorporated division of Atmos, including Western.

See attached United Cities Gas WNA tariffs for Tennessee and Georgia..

WEATHER NORMALIZATION ADJUSTMENT (WNA) RIDER

Provisions for Adjustment

The base rate per Ccf (100,000 Btu) for gas service set forth in Rate Schedules 810, 820 and 830 applicable to residential and commercial customers of United Cities Gas Company, a Division of ATMOS Energy Corporation, (Company) shall be adjusted by an amount hereinafter described, which amount is referred to as the "Weather Normalization Adjustment."

Definitions

For purpose of this Rider:

"Commission" means the Georgia Public Service Commission

"Relevant Rate Order" means the final order of the Commission in the most recent litigated rate case of the Company fixing the rates of the Company or the most recent final order of the Commission specifically prescribing or fixing the factors and procedures to be used in the application of this Rider.

Computation of Weather Normalization Adjustment

The Weather Normalization Adjustment shall be computed to the nearest one-hundredth cent per Ccf by the following formula:

$$WN_i \quad = \quad R_i \quad \frac{(HSF_i \ \ (NDD - ADD))}{(BLi \ \ + (HSFi \ x \ ADD)}$$

Where

I	=	any particular Rate Schedule 810, 820 and/or 830 or billing classification within any such particular Rate Schedule that contains more than one billing classification
WNA_i	=	Weather Normalization Adjustment Factor for the i^{th} rate schedule or classification expressed in cents per Ccf.
R_i	=	base rate of temperature sensitive sales for the i^{th} schedule or classification utilized by the Commission in the Relevant Rate Order for the purpose of determining normalized test year revenues

WEATHER NORMALIZATION ADJUSTMENT (WNA) RIDER (Continued)

HSF_i	=	heat sensitive factor for the i^{th} schedule or classification utilized by the Commission in the Relevant Rate Order for the purpose of determining normalized test year revenues
NDD	=	normal billing cycle heating degree days utilized by the Commission in the Relevant Rate Order for the purpose of determining normalized test year revenues
ADD	=	actual billing cycle heating degree days
BL_i	=	base load sales for the i^{th} schedule or classification utilized by the Commission in the Relevant Rate Order for the purpose of determining normalized test year revenues

Filing with Commission

The Company will file as directed by the Commission (a) a coy of each computation of the Weather Normalization Adjustment, (b) a schedule showing the effective date of each such Weather Normalization Adjustment, and (c) a schedule showing the factors or values derived from the Relevant Rate Order used in calculating such Weather Normalization Adjustment.

WEATHER NORMALIZATION ADJUSTMENT (WNA) RIDER

Provisions for Adjustment

The base rate per therm/Ccf (100,000 Btu) for gas service set forth in any Rate Schedules utilized by the Tennessee Regulatory Authority in determining normalized test period revenues shall be adjusted by an amount hereinafter described, which amount is referred to as the "Weather Normalization Adjustment." The Weather Normalization Adjustment shall apply to all residential and commercial bills based on meters read during the revenue months of November through April.

Definitions

For purpose of this Rider:

"Regulatory Authority" means the Tennessee Regulatory Authority

"Relevant Rate Order" means the final order of the Regulatory Authority in the most recent litigated rate case of the Company fixing the rates of the Company or the most recent final order of the Regulatory Authority specifically prescribing or fixing the factors and procedures to be used in the application of this Rider.

Computation of Weather Normalization Adjustment

The Weather Normalization Adjustment shall be computed to the nearest one-hundredth cent per therm/Ccf by the following formula:

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

Where

i = any particular Rate Schedule or billing classification within any such particular Rate Schedule that contains more than one billing classification

WNA_i = Weather Normalization Adjustment Factor for the i^{th} rate schedule or classification expressed in cents per therm/Ccf

R_i = weighted average base rate of temperature sensitive sales for the i^{th} schedule or classification utilized by the Tennessee Regulatory Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues

WEATHER NORMALIZATION ADJUSTMENT (WNA) RIDER (Continued)

HSF_i = heat sensitive factor for the ith schedule or classification utilized by the Regulatory Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues

NDD = normal billing cycle heating degree days utilized by the Regulatory Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues

ADD = actual billing cycle heating degree days

BL_i = base load sales for the i^{th} schedule or classification utilized by the Regulatory Authority in the Relevant Rate Order for the purpose of determining normalized test year revenues

Filing with Regulatory Authority

The Company will file as directed by the Regulatory Authority (a) a copy of each computation of the Weather Normalization Adjustment, (b) a schedule showing the effective date of each such Weather Normalization Adjustment, and (c) a schedule showing the factors or values derived from the Relevant Rate Order used in calculating such Weather Normalization Adjustment.

Heat Use/Base Use Factors

	Residential		Commercial	
Town	Base use Ccf	Heat use Ccf/HDD	Base use Ccf	Heat use Ccf/HDD
Union City	13.906292	.156369	124.595029	.453633
Columbia Shelbyville Franklin Murfreesboro	13.035323	.173948	99.021858	.624513
Maryville Morristown	13.886330	.153366	111.454966	.658649
Johnson City Elizabethton Kingsport Greeneville Bristol	10.696903	.162066	169.773651	.611201

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 62
Witness: Daniel M. Ives

Data Request:

62. Reference Mr. Ives' testimony at page 3, line 7. What is a cross-class subsidy in the allocation of costs? Explain, and provide the numerical amount of claimed cross-class subsidy in the allocation of costs.

Response:

62. An example of a cross-class subsidy in the allocation of costs would be the design of rates utilizing less than system average rate of return for a particular class of customers. Witness Petersen's Class Cost of Service study indicates that the Residential class is earning 7.06%, which is less than system average. Unless or until the Residential class is allocated a system average rate of return (a cost) in the class cost of service and in approved rates, some other class, or the company, will subsidize Residential customers.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 63
Witness: Daniel M. Ives

Data Request:

63. Reference Mr. Ives' testimony at page 3, lines 28-29. Is Mr. Ives saying here that Mr. Smith is proposing rates that would shift revenue responsibility to the residential class? If not, explain how Mr. Smith is proposing to increase the share of costs allocated to the residential class.

Response:

63. Yes.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 64
Witness: Daniel M. Ives

Data Request:

64. Reference Mr. Ives' testimony at page 5, lines 9-11. Does Mr. Ives believe that Western administers its current new customers hook-up program so that the new potential consumption and revenue warrants the capital expenditures and makes the investment economically feasible? If yes, please explain the logic Mr. Ives uses in reaching his conclusion.

Response:

64. Mr. Ives' testimony at page 5, lines 9-11, speaks to the issue as to whether Western's tariff complies with the Commission's regulations. Mr. Ives states that he believes that it does. Mr. Ives believes that the Commission's regulations requiring free, no-charge Residential customer hook-ups (including a meter, regulator, service line, and up to 100 feet of main) may result in Western making uneconomic customer connections.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 65(a)
Witness: Thomas H. Petersen

Data Request:

Reference Distribution Mains Study, Sheet 7 of 9 (shows minimum system and zero-intercept data).

a. Explain how it is that the two methods, which are supposed to reveal the customer component of distribution mains can indicate that 78.32 percent of mains costs are customer related on the one hand, and that 22.64 percent of mains costs are customer related on the other hand.

Response:

a) The 78.32 percent is calculated as the customer component of the cost of distribution mains using the minimum system method on Sheet 7 of the class cost of service study. The feet and cost of mains with diameters greater than 2 inches are shown on line 32. Line 33 shows the feet of mains with diameters greater than 2 inches repriced at the average cost per foot of 2 inch mains. Line 34 shows the difference in costs between line 32 and 33. This cost difference of $13,569,133 is assigned to the demand component. The total mains cost is $62,583,308 from column 5, and line 11. The customer component is the difference of $49,014,175 or 78.32 percent of the total cost.

The 22.64 percent is calculated as the customer component of the cost of distribution mains using the regression minimum method on Sheet 7 of the study. The regression analysis produces an equation with a zero intercept of 0.8915. Multiplying the total feet of distribution mains of 15,895,412 by 0.8915 on line 36 produces $14,171,506 which is assigned to the customer component. The 22.64% is the $14,171,506 divided by $62,583,308.

The minimum system method allocates a higher percent of mains cost to the customer component. It considers the cost of a 2 inch diameter main to be customer related and the additional cost of larger mains to be demand related. The regression minimum method considers the cost of theoretical zero diameter main to be customer related and the additional cost of mains to be demand related. The cost of a theoretical zero diameter main is less than the cost of a 2 inch diameter main.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 65(b)
Witness: Thomas H. Petersen

Data Request:

b. Please provide the study and workpapers that support the $49,014,175 customer amount of mains.

Response:

b) Please see the response to 65(a)

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 65(c)
Witness: Thomas H. Petersen

Data Request:

c. Please provide the set of data points that were regressed to determine the slope in Y – A + B * X relationship between pipe size and cost.

Response:

c) The data inputs are listed in columns 2, 3 and 5 of Sheet 7 of the class cost of service study. These columns list the diameter of the mains, the number of feet and the cost respectively.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 65(d)
Witness: Thomas H. Petersen

Data Request:

d. Provide all measures of goodness of statistical fit that are calculated in the software package used to regress pipe size and cost.

Response:

d) No software package was used to regress pipe size and cost. The regression calculation is fully contained on sheet 7 of the class cost of service study.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 66
Witness: Thomas H. Petersen

Data Request:

Explain the Company's understanding of the theory of how the minimum system concept and the zero-intercept concept reveal the customer component of distribution mains.

Response:

Both the minimum system and the zero-intercept methods of classifying mains costs between customer and demand components assume that there is a zero or minimum size main necessary to connect the customer to the system. The minimum system method prices all distribution mains at the historic unit cost of the smallest main routinely installed in the system and classifies this as customer costs. The remaining cost of distribution mains is classified as demand costs. The zero-intercept method classifies the cost of a system of theoretical zero-diameter mains to customer costs and the remainder to demand costs.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 67
Witness: Thomas H. Petersen

Data Request:

Explain why the Company chose to use the zero-intercept method of determining customer costs of distribution mains rather than the zero-intercept method.

Response:

Western's Case No. 90-013 was the last case in which the Commission commented on a Western class cost of service study. The following statement from page 48 of the Commission's Order in that case explains Western's choice of the zero-intercept method.

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

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 68
Witness: Daniel M. Ives

Data Request:

68. Reference Mr. Ives' testimony at page 6, lines 3-5. Explain how new residential hook-ups that result in monetary loss to the Company are consistent with Mr. Ives' testimony at page, 5, lines 9-11.

Response:

68. Mr. Ives' testimony at page 5, lines 9-11, does not assert that the company's new residential hook-ups are economic: the testimony merely cites the company's tariff provision and that it conforms with Commission regulations.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 69
Witness: Daniel M. Ives

Data Request:

69. Reference Mr. Ives' testimony at page 6, lines 7-10. Please provide a numerical example showing for a given amount of revenue from the proposed charge at Mr. Ives' choosing, the amount that would be credited to plant, the amount that would become a tax expense, the amount of tax expense, and the amount that become return.

Response:

69. See Exhibit DMI-6, Schedule 1 of 3, "Accounting for Charge Revenue" section of the exhibit. This section provides the estimated accounting for Premises Charge revenues.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 70
Witness: Daniel M. Ives

Data Request:

70. Reference Exhibit DMI-2, Schedule 1 of 2. Please provide information in the same format that is limited to facility investment related only to, or changes between the two-time period solely because, facility investments associated with new customer additions.

Response:

70. Mr. Ives has not performed the study requested and does not believe that the historical data is available to perform such a study in the format requested to isolate only facility investments associated with new customer additions for each of the years 1994-1998.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 71
Witness: Gruber

Data Request:

Reference Exhibit DMI-3, Schedule 1. Presumably, since Western's customers are already responsible for the costs of services from the curb or property line to the gas-using structure, the $906.94 services cost per customer is the cost of the service line from the main to the curb, cub box, or property line. Please explain why it is that the cost of services is about 2.7 times the cost of mains, per customer, as shown on this exhibit.

Response:

Main, for new construction, is normally installed before the streets, curbs and gutters or driveways have been established. This reduces the costs for clean up and fittings. The fixed cost associated with installing pipe, the labor cost to gather materials, equipment and transportation to the job site, are usually spread over a larger footage project when installing main. Services, however, are installed upon request and are normally after other utilities are in place, the final street bed has been poured and the curbs and gutters are in place. With services the fixed cost is spread over a smaller footage project. Adding to the service installation cost is the requirement of boring or cutting the street to install the service. Boring costs are approximately 2.5 times the cost of direct burial installation. Additional care also has to be taken to avoid other utilities in place as well as for the customer's property.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 72
Witness: Daniel M. Ives

Data Request:

72. Explain why the "return on investment" portion of the proposed premises charge needs to be gross-up for income taxes.

Response:

72. Return on investment is taxable income. The "return on investment" portion of the proposed Premises Charge is based on a pre-tax rate of return which includes tax gross-up.

    If the question means to ask why the "return of investment" portion of the proposed Premises Charge is grossed-up for income taxes, it is because IRS regulations state that contributions to a corporation "in aid of construction or any other contribution as a customer or potential customer is taxable to the corporation."

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 73
Witness: Daniel M. Ives

Data Request:

73. If Western is not going to depreciate the Excess Investment (Ives' testimony, page 10, line 12), for either book and/or tax purposes, please explain why not.

Response:

73. Western will depreciate the total cost of plant, including the Excess Investment portion, for book and for tax purposes.

Data Request:

74. Assume, in a two-person world, person A owns the only house and refuses to sell to person B, necessitating that person B build a new house. Further assume that the cost of extending utility service to the new house costs $100 more than the embedded cost of utility facilities to the already existing house. In Mr. Ives' opinion, who has caused the utility to incur the extra $100 cost? Please explain.

Response:

74. In this hypothetical example, Person B requested utility service at a new address. The utility, presumably complying with Commission regulations requiring free hook-ups to all persons that request service, incurred $100 in incremental facility costs to provide that service to Person B. Mr. Ives believes that the Commission and Person B jointly caused the utility to incur the extra $100 cost. Commission regulations do not require Person A to sell his house to Person B.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 75
Witness: Daniel M. Ives

Data Request:

75. Reference Mr. Ives' testimony at page 13, lines 1-2. Is the 10 percent amount a 10 percent per year amount? Or is it a 10 percent of the initial premises charge amount? Other. Please explain, and provide a numerical example within and a numerical example without the 10 percent range.

Response:

75. See proposed tariff sheet no. 67, provision v: "The company shall update the amounts of the charges annually and, upon Commission approval, implement such new charges prospectively for new residential service connections in the ensuing year. If the amount of increase or decrease to the Premises Charge is less than 10%, the company may waive implementation of such increase or decrease and charge the existing Premises Charge for new connections made in the ensuing year.

For example, if the Premises Charge as approved for year 2001 additions is $13.05 (with main extension) and the Premises Charge as computed for year 2002 additions is $ 14.34, the Company may waive the increase of the charge and continue to utilize $13.05 because the amount of the increase, $ 1.29, is less than 10% of the previously approved charge. However, if the charge computed to be $14.35 or more, the increase to the charge would not be waived under the proposed tariff provision, as the increase, $1.30, is 10% of the previously approved charge.

The purpose of designing flexibility into the charge is to allow for fluctuations of data that may be due to booking or timing differences, such that those data fluctuations not necessitate implementation of a different charge for connections made in the ensuing year.

76

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 76
Witness: Daniel M. Ives

Data Request:

76. Reference Mr. Ives' testimony at page 18, lines 16-20. Please provide workpapers detailing the $15.44/year and the $2.4 million amounts.

Response:

76. See response to Kentucky PSC Data Request No. 2, Question No. 55 (e), a copy of which is attached.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request No. 2
DR Item 55 (e)
Witness: Daniel M. Ives

Data Request:

55. Refer to the Direct Testimony of Daniel Ives and the response to Item 56 of the Commission's July 16, 1999 Order.

e. Provide the calculations, along with a narrative explanation, of the "Facilities Adjustment Charge" of $15.44 per year for all residential customers that Mr. Ives suggests Western be allowed to implement if the Commission rejects the proposed premises charge.

Response:

55 (e) See attached schedule.

If the Commission elects to implement the alternative "Facilities Adjustment Charge," it may be computed by estimating the annual amount of Excess Investment associated with new Residential hook-ups that require main extension and a Meter, Service Line and Regulator (MSR), and the annual amount of Excess Investment associated with new Residential hook-ups that require MSR only. The combined annual Excess Investment is grossed-up for Federal and State taxes and then divided by the estimated number of Residential customers in 2001 to produce the annual cost per Residential customer of $15.44, as illustrated below:

Excess Investment	Amount Excess Investment 1/	Budgeted Annual No. of Connections 2/	Total
Main and MSR	$858	1450	$1,244,100
MSR Only	$740	250	$185,000
		1700	$1,429,100
Tax Gross-up Factor (.5964) 3/			
Annual Excess Investment - Grossed-up for Taxes			$2,396,211
Number of Customers - 2001 4/			155220
Annual Cost (incl. Tax) /All Residential Customers			$15.44
Rolled-in Monthly Cost For All Residential Customers			$1.29

No carrying charges are imputed as recoveries and expenditures are assumed to occur ratably.

1/ Refer to Exhibit DMI-5, Schedule 1 for Excess Investment.
2/ Refer to Exhibit DMI-6, Schedule 1 for budgeted number of New Residential Customers.
3/ Refer to Exhibit DMI 5, Schedule 2 for tax factor.
4/ Residential Customers 9/30/98 151820 (Exhibit DMI 2, Schedule 2)
1999 Additions 1700 (Exhibit DMI-6, Schedule 1)
2000 Additions 1700 (Exhibit DMI-6, Schedule 1)
155220

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 77
Witness: Daniel M. Ives

Data Request:

77. Reference DMI-5, Schedule 1 of 2. Provide workpapers detailing the derivation of each the Return of Excess Investment charges and each of the Carry Cost on Excess Investment charges (6, in total) shown in the Demand Charge for Month section of this schedule.

Response:

77. See Footnotes 1-4 on Exhibit DMI-5, Schedule 1, detailing the derivation of each of the charges. See Schedule 2 of Exhibit DMI-5 for the computation of carrying charges.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 78
Witness: Daniel M. Ives

Data Request:

78. Reference DMI-5, Schedule 1 of 2. Please show how the annual revenue provided by this rate is sufficient each year, and no more than sufficient, to recover total excess investment, return, taxes on return, and, apparently, taxes on recovery of excess investment.

Response:

78. See Exhibit DMI-6, Schedule 1, which illustrates the accounting for the charge assuming 1700 new Residential Premise Charges annually over the years 2001-2005.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 79
Witness: Daniel M. Ives

Data Request:

79. If a new hook-up was subject to the proposed premises' charge for 14 years, was sold but vacant for one year, what would be the premises charge responsibility of the new owners? One year? None? Other? Explain.

Response:

79. As indicated in the proposed tariff language, the charge "shall be payable for one hundred eighty (180) months and is applicable to the service address, regardless of changes in ownership…." Thus, the new owner would be responsible for the remaining 12 unpaid months of the charge, unless paid by the previous owner.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 80
Witness: Daniel M. Ives

<u>Data Request:</u>

80. How and when would new owners of a re-sold residence subject to a premises charge find out about the applicability of such a charge?

<u>Response:</u>

80. Western Kentucky Gas would notify new owners of the charge at the time they apply for an account. This notification would be provided with new customer information.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 81
Witness: Daniel M. Ives

Data Request:

81. Are potential investors aware that Western currently does not have a premises charge? If so, explain how such information has not been factored into their decisions as to whether to invest in Western, other utilities, or any other business.

Response:

81. Mr. Ives is not aware of what "potential investors" may or may not have knowledge of concerning Western Kentucky Gas, except that such investors would be aware of Western's inadequate earned rate of return through the financial reports of its parent company, Atmos Energy Company.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 82
Witness: Daniel M. Ives

Data Request:

82. Reference Exhibit DMI-5, Schedule 1 of 2. Please provide the capitalized O&M expense included in the $858.15 total excess investment.

Response:

82. Approximately 34.64%, or $ 297.26, based on overhead application rate of 53% of direct costs.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 83
Witness: Daniel M. Ives

Data Request:

83. Please provide a demonstration that the proposed pricing scheme for the total excess investment produces the same cost to ratepayers as would traditional Kentucky regulatory treatment of these same excess investment costs.

Response:

83. The proposed Premises Charge would result in higher costs for customers that receive the benefit of Western's investment in facilities growth, as those customers would pay for all of the excess of incremental cost above embedded cost, along with associated income taxes. However, all Residential customers would, in subsequent rate cases, receive the rate benefit of the credits to Account 271, contributions, generated by the Premises Charge.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 84
Witness: Daniel M. Ives

Data Request:

84. For the traditional regulatory treatment, assume the total excess investment is allowed into rate base, qualifying for recovery and return and associated taxes. If the costs to the ratepayer are different, please explain why the costs are different, and provide the annual and total costs to ratepayers under your proposed regulatory scheme for total excess investment and under the traditional regulatory scheme.

Response:

84. Amounts collected through the Premises Charge attributable to recovery of investment would be credited to Account 271 and offset against rate base, to the benefit of all Residential customers as base rates would be reduced by the cost of service impact.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item #85
Witness: Donald P. Burman

Data Request:

85. Please provide depreciation rates for mains, services, meters and regulators, all of the types included on Exhibit DMI-1, Schedule 1.

Response:

The depreciation rates for these items are included in the Deloitte & Touche Depreciation Study, Page 14, Column 6.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 86
Witness: Daniel M. Ives

Data Request:

86. Assume a mains extension project to hook-up a new customer costs $750.00. Consistent with Western's Distribution Mains Extension Rules and Regulations, suppose $500.00 is incurred at no cost to the customer, and Western charges the customer for the extra $250 cost, plus another, say, $125 for income taxes. Please provide a balance sheet indicating how the Company's plant accounts would appear before and after this project. Please include account numbers affected by this project.

Response:

Balance Sheet Account	Account Number	Beginning Balance	Dr.	Cr.	Ending Balance
Cash	131	Unknown	$375		Unknown
CWIP	107	Unknown		$250	Unknown
Taxes Accrued	236	Unknown		$125	Unknown
CWIP	107	Unknown	$750		Unknown
Acct. Payable & Materials Inventory	232, 184	Unknown		$750	Unknown
Gas Plant in Service	101	Unknown	$500		Unknown
CWIP	107	Unknown		$500	Unknown

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 87
Witness: Betty Adams

Data Request:

Please provide the amounts of contributions in aid of construction booked in 1998.

Response:

In fiscal year 1998, Western Kentucky Gas did not enter into any agreements to receive contributions in aid of construction. Therefore, the dollar amount of contributions in aid of construction booked in fiscal year 1998 was "$0.00".

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 88
Witness: Daniel M. Ives

Data Request:

88. Reference Exhibit DMI-3, Schedule 1. Are the total cost of installed units amounts gross plant amounts? Plant amounts net of CIAC? Other? Explain. If the amounts are not gross plant amounts, please provide the itemized additions (by amounts and description) that are necessary to convert the referenced amounts to gross plant amounts.

Response:

88. Gross plant amounts, including overheads.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 89
Witness: Daniel M. Ives

Data Request:

89. Normally, constant capital cost recovery implies a diminishing stream of revenue requirements (costs) over time. Normally, a constant annual payment implies an increasing recovery of capital costs. Your Total Excess Investment cost recovery scheme embodied in your proposed Premises Charge is characterized by both constant prices and constant capital cost recovery. Explain conceptually on how you derived your constant payment/constant cost recovery Premises Charge(s). If the arithmetic of this requested derivation has already been included as part of a response to some other OAG question, please reference that response. If not otherwise provided, please provide the workpapers showing the requested derivation.

Response:

89. The Excess Investment embodied in the Premises Charge is assumed to be collected equally each month over 180 months, as noted in footnote 3 on Exhibit DMI-5, Schedule 1. Carrying costs do, in fact decline over time, as shown on Exhibit DMI-5, Schedule 2, but payments have been levelized, as noted in footnote 4 on Exhibit DMI-5, Schedule 1.

Western Kentucky Gas Company

Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 90
Witness: Hack

Data Request:

Please provide storage injections and withdrawals on a daily basis for 1998.

Response:

See the attached twelve monthly summaries (Attachment AG DR Item 90) reflecting the injections and withdrawals on a daily basis for calendar year 1998.

WESTERN KENTUCKY G[illegible]OMPANY
UNDERGROUND STORAGE REPORT
January 1998

	BON HARBOR FIELD		HICKORY FIELD		OWENSBORO FIELD		GRANDVIEW FIELD		KIRKWOOD FIELD		St. CHARLES		FIELD TOTALS		
DAY	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	DAY
1	0	4,744	0	2,290	0	0	0	1,572	0	0	0	14,821	0	23,427	1
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
3	0	0	16,351	0	0	0	0	0	0	0	0	0	16,351	0	3
4	0	0	19,508	0	0	0	0	0	0	0	0	0	19,508	0	4
5	0	0	17,922	0	0	0	0	0	0	0	0	0	17,922	0	5
6	0	0	16,406	0	0	0	0	0	0	0	0	0	16,406	0	6
7	0	0	14,354	0	0	0	0	0	0	0	0	0	14,354	0	7
8	0	33	0	55	0	0	0	21	0	0	0	20,563	0	20,672	8
9	0	10,688	0	12,921	0	0	0	2,743	0	0	0	22,478	0	48,830	9
10	0	6,786	0	6,675	0	0	0	2,556	0	0	0	22,240	0	38,257	10
11	0	5,091	0	3,038	0	0	0	2,336	0	0	0	16,383	0	26,848	11
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12
13	0	14,201	0	13,022	0	0	0	2,471	0	0	0	27,390	0	57,084	13
14	0	5,377	0	4,152	0	0	0	1,723	0	0	0	13,743	0	24,995	14
15	0	9,773	0	9,968	0	0	0	1,784	0	0	0	24,063	0	45,588	15
16	0	7,622	0	6,249	0	0	0	1,905	0	0	0	27,972	0	43,748	16
17	0	10,940	0	7,507	0	0	0	1,543	0	0	0	25,904	0	45,894	17
18	0	4,809	0	46	0	0	0	1,806	0	0	0	17,278	0	23,939	18
19	0	15,996	0	15,875	0	0	0	2,182	0	0	0	30,884	0	64,937	19
20	0	8,447	0	8,609	0	0	0	2,126	0	0	0	23,919	0	43,101	20
21	0	6,021	0	3,230	0	0	0	1,902	0	0	0	13,345	0	24,498	21
22	0	3,069	0	2,050	0	0	0	952	0	0	0	18,192	0	24,263	22
23	0	11,142	0	4,088	0	0	0	1,603	0	0	0	22,065	0	38,898	23
24	0	9,380	0	4,938	0	0	0	2,056	0	0	0	21,319	0	37,693	24
25	0	4,169	0	0	0	0	0	691	0	0	0	21,352	0	26,212	25
26	0	0	0	0	0	0	0	606	0	0	0	15,485	0	16,091	26
27	0	1,622	0	0	0	0	0	1,366	0	0	0	15,722	0	18,710	27
28	0	0	0	0	0	0	0	32	0	0	0	175	0	207	28
29	0	5,344	0	1,923	0	0	0	2,164	0	0	0	19,231	0	28,662	29
30	0	15,902	0	261	0	0	0	2,138	0	0	0	24,598	0	42,899	30
31	0	1,731	0	0	0	0	0	1,564	0	0	0	18,297	0	21,592	31
SUB-TOTALS	0	162,887	84,541	106,897	0	0	0	39,842	0	0	0	477,419	84,541	787,045	
SALES		0		54		0		96		0		0		150	
MCF	0	162,887	84,541	106,951	0	0	0	39,938	0	0	0	477,419	84,541	787,195	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GA[illegible]MPANY
UNDERGROUND STORAG[illegible]EPORT
February 1998

	BON HARBOR FIELD		HICKORY FIELD		OWENSBORO FIELD		GRANDVIEW FIELD		KIRKWOOD FIELD		St. CHARLES		FIELD TOTALS		
DAY	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	DAY
1	0	0	0	0	0	0	0	0	0	0	0	8,552	0	8,552	1
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
3	0	11,203	0	522	0	0	0	2,124	0	0	0	21,715	0	35,564	3
4	0	17,959	0	15,576	0	0	0	1,936	0	6,135	0	25,470	0	67,076	4
5	0	12,886	0	7,965	0	0	0	1,897	0	6,179	0	17,869	0	46,796	5
6	0	10,915	0	1,944	0	0	0	1,841	0	4,267	0	17,190	0	36,157	6
7	0	2,525	0	0	0	0	0	1,805	0	5,117	0	17,189	0	26,636	7
8	0	0	0	0	0	0	0	1,590	0	3,534	0	12,947	0	18,071	8
9	0	0	0	0	0	0	0	1,780	0	4,131	0	16,518	0	22,429	9
10	0	11,145	0	0	0	0	0	1,779	0	3,958	0	18,826	0	35,708	10
11	0	14,470	0	8,829	0	0	0	1,575	0	4,994	0	21,079	0	50,947	11
12	0	14,995	0	9,345	0	0	0	1,464	0	4,695	0	20,699	0	51,198	12
13	0	11,218	0	7,327	0	0	0	1,492	0	4,708	0	19,950	0	44,695	13
14	0	6,637	0	0	0	0	0	1,272	0	3,228	0	15,362	0	26,499	14
15	0	2,212	0	0	0	0	0	1,525	0	3,352	0	16,303	0	23,392	15
16	0	2,351	0	0	0	0	0	862	0	2,064	0	8,149	0	13,426	16
17	0	9,630	0	5,297	0	0	0	1,363	0	2,761	0	16,678	0	35,729	17
18	0	10,386	0	8,354	0	0	0	1,439	0	4,191	0	17,734	0	42,104	18
19	0	6,929	0	1,859	0	0	0	1,494	0	3,954	0	16,487	0	30,723	19
20	0	5,748	0	5,639	0	0	0	1,447	0	3,731	0	16,233	0	32,798	20
21	0	0	0	1,463	0	0	0	270	0	1,059	0	4,514	0	7,306	21
22	0	517	0	175	0	0	0	82	0	204	0	13,929	0	14,907	22
23	0	8,012	0	8,086	0	0	0	1,101	0	3,662	0	15,086	0	35,947	23
24	0	2,245	0	990	0	0	0	98	0	363	0	3,434	0	7,130	24
25	0	0	0	0	0	0	0	0	0	4	0	22	0	26	25
26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26
27	0	0	0	0	0	0	0	0	0	31	0	0	0	31	27
28	0	3,251	0	1,798	0	0	0	496	0	96	0	6,447	0	12,088	28
29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	29
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31
SUB-TOTALS	0	165,234	0	85,169	0	0	0	30,732	0	76,418	0	368,382	0	725,935	
SALES		0		43		0		94		0		0		137	
MCF	0	165,234	0	85,212	0	0	0	30,826	0	76,418	0	368,382	0	726,072	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GA[illegible]MPANY
UNDERGROUND STORAG[illegible]REPORT
March 1998

DAY	BON HARBOR FIELD IN	BON HARBOR FIELD OUT	HICKORY FIELD IN	HICKORY FIELD OUT	OWENSBORO FIELD IN	OWENSBORO FIELD OUT	GRANDVIEW FIELD IN	GRANDVIEW FIELD OUT	KIRKWOOD FIELD IN	KIRKWOOD FIELD OUT	St. CHARLES IN	St. CHARLES OUT	FIELD TOTALS IN	FIELD TOTALS OUT	DAY
1	0	15,633	0	8,026	0	0	0	1,499	0	0	0	19,949	0	45,107	1
2	0	17,247	0	10,615	0	0	0	1,552	0	5,589	0	20,761	0	55,764	2
3	0	17,123	0	9,598	0	0	0	1,427	0	5,142	0	21,119	0	54,409	3
4	0	15,126	0	8,576	0	0	0	1,478	0	4,270	0	16,540	0	45,990	4
5	0	15,285	0	8,843	0	0	0	1,408	0	4,492	0	17,450	0	47,478	5
6	0	5,775	0	1,832	0	0	0	1,286	0	2,937	0	8,760	0	20,590	6
7	0	0	0	0	0	0	0	1,131	0	0	0	6,797	0	7,928	7
8	0	1,943	0	69	0	0	0	863	0	165	0	7,048	0	10,088	8
9	0	14,954	0	7,661	0	0	0	1,078	0	5,978	0	24,186	0	53,857	9
10	0	13,369	0	6,765	0	0	0	1,004	0	4,972	0	23,802	0	49,912	10
11	0	13,121	0	5,700	0	0	0	2,835	0	3,516	0	23,801	0	48,973	11
12	0	12,420	0	6,420	0	0	0	2,479	0	2,676	0	22,282	0	46,277	12
13	0	10,329	0	2,122	0	0	0	2,714	0	3,449	0	16,603	0	35,217	13
14	0	1,796	5,665	0	0	0	0	615	0	0	0	9,140	5,665	11,551	14
15	0	1,553	0	0	0	0	0	910	0	80	0	15,047	0	17,590	15
16	0	2,860	0	0	0	0	0	652	0	15	0	11,627	0	15,154	16
17	0	0	1,471	0	0	0	0	0	0	0	0	0	1,471	0	17
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19
20	0	4,676	0	6,894	0	0	0	2,484	0	1,865	0	18,443	0	34,362	20
21	0	3,380	0	7,485	0	0	0	2,823	0	4,294	0	18,762	0	36,744	21
22	0	970	0	2,029	0	0	0	2,698	0	564	0	9,635	0	15,896	22
23	0	0	0	2,492	0	0	0	2,630	0	87	0	14,064	0	19,273	23
24	0	0	0	3,986	0	0	0	2,547	0	2,417	0	12,566	0	21,516	24
25	0	0	0	4	0	0	0	366	0	0	0	2,576	0	2,946	25
26	0	0	410	0	0	0	0	0	0	0	0	0	410	0	26
27	0	0	8,537	0	0	0	0	0	0	0	0	0	8,537	0	27
28	0	0	25,041	0	0	0	0	0	0	0	0	0	25,041	0	28
29	0	0	23,867	0	0	0	0	0	0	0	0	0	23,867	0	29
30	0	0	13,314	0	0	0	0	0	0	0	0	0	13,314	0	30
31	0	0	2,042	0	0	0	0	0	0	0	0	0	2,042	0	31
SUB-TOTALS	0	167,560	80,347	99,117	0	0	0	36,479	0	52,508	0	340,958	80,347	696,622	
SALES		0		36		0		118		0		0		154	
MCF	0	167,560	80,347	99,153	0	0	0	36,597	0	52,508	0	340,958	80,347	696,776	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GA MPANY
UNDERGROUND STORAGE REPORT
April 1998

DAY	BON HARBOR FIELD IN	BON HARBOR FIELD OUT	HICKORY FIELD IN	HICKORY FIELD OUT	OWENSBORO FIELD IN	OWENSBORO FIELD OUT	GRANDVIEW FIELD IN	GRANDVIEW FIELD OUT	KIRKWOOD FIELD IN	KIRKWOOD FIELD OUT	St. CHARLES IN	St. CHARLES OUT	FIELD TOTALS IN	FIELD TOTALS OUT	DAY
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
4	0	0	0	0	0	0	0	0	0	98	0	17,135	0	17,233	4
5	0	0	0	0	0	0	0	0	0	3	0	11,302	0	11,305	5
6	0	0	0	0	0	0	0	0	0	0	0	10,529	0	10,529	6
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8
9	0	0	0	0	0	0	0	0	0	0	0	9,973	0	9,973	9
10	0	0	0	0	0	0	0	0	0	0	0	877	0	877	10
11	0	0	3,352	0	0	0	0	0	0	35	0	0	3,352	35	11
12	0	0	7,918	0	0	0	0	0	0	0	0	0	7,918	0	12
13	0	0	14,894	0	0	0	0	0	0	0	3,680	3	18,574	3	13
14	0	0	18,104	6,327	0	0	0	0	0	0	5,289	0	23,393	6,327	14
15	0	0	17,462	13,488	0	0	0	0	0	0	11,756	0	29,218	13,488	15
16	0	0	14,458	4,824	0	0	0	0	0	0	12,019	0	26,477	4,824	16
17	0	0	1,986	0	0	0	0	0	0	116	0	0	1,986	116	17
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18
19	0	0	2,220	0	0	0	0	0	0	200	0	0	2,220	200	19
20	0	0	1,866	0	0	0	0	0	0	0	0	0	1,866	0	20
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22
23	9,419	0	0	0	0	0	0	0	0	0	0	0	9,419	0	23
24	9,756	0	0	0	0	0	0	0	0	0	0	0	9,756	0	24
25	9,755	0	0	0	0	0	0	0	0	0	0	0	9,755	0	25
26	9,729	0	0	0	0	0	0	0	0	0	0	0	9,729	0	26
27	9,655	0	0	0	0	0	0	0	0	0	0	0	9,655	0	27
28	9,551	0	0	0	0	0	0	0	0	0	0	0	9,551	0	28
29	9,459	0	0	0	0	0	0	0	0	0	0	8,662	9,459	8,662	29
30	9,364	0	0	0	0	0	0	0	0	0	0	6,059	9,364	6,059	30
31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31
SUB-TOTALS	76,688	0	82,260	24,639	0	0	0	0	0	452	32,744	64,540	191,692	89,631	
SALES		0		28		0		77		0		0		105	
MCF	76,688	0	82,260	24,667	0	0	0	77	0	452	32,744	64,540	191,692	89,736	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GAS [illegible]PANY
UNDERGROUND STORAGE [illegible]EPORT
May 1998

	BON HARBOR FIELD		HICKORY FIELD		OWENSBORO FIELD		GRANDVIEW FIELD		KIRKWOOD FIELD		St. CHARLES		FIELD TOTALS		
DAY	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	DAY
1	9,308	0	0	0	0	0	0	0	2,795	0	0	0	12,103	0	1
2	9,216	0	0	0	0	0	0	0	2,927	0	0	0	12,143	0	2
3	9,150	0	0	0	0	0	0	0	2,927	0	0	0	12,077	0	3
4	9,066	0	0	0	0	0	0	0	2,927	0	0	0	11,993	0	4
5	9,291	0	0	0	0	0	0	0	2,927	0	0	0	12,218	0	5
6	9,351	0	0	0	0	0	0	0	2,927	0	0	0	12,278	0	6
7	9,315	0	0	0	0	0	0	0	2,927	0	0	0	12,242	0	7
8	9,565	0	0	0	0	0	0	0	2,927	0	0	0	12,492	0	8
9	9,492	0	0	0	0	0	0	0	2,927	0	0	0	12,419	0	9
10	9,417	0	0	0	0	0	0	0	2,927	0	0	0	12,344	0	10
11	9,350	0	0	0	0	0	0	0	2,927	0	0	0	12,277	0	11
12	9,378	0	0	0	0	0	0	0	2,927	0	0	0	12,305	0	12
13	9,339	0	0	0	0	0	0	0	2,927	0	0	0	12,266	0	13
14	9,284	0	0	0	0	0	0	0	2,927	0	0	0	12,211	0	14
15	9,253	0	0	0	0	0	0	0	2,927	0	0	0	12,180	0	15
16	9,223	0	0	0	0	0	0	0	2,927	0	0	0	12,150	0	16
17	9,172	0	0	0	0	0	0	0	2,927	0	0	0	12,099	0	17
18	9,594	0	0	0	0	0	0	0	2,927	0	0	0	12,521	0	18
19	9,700	0	0	0	0	0	0	0	2,927	0	9,839	0	22,466	0	19
20	9,643	0	0	0	0	0	0	0	2,927	0	12,292	0	24,862	0	20
21	9,585	0	0	0	0	0	0	0	2,872	0	10,292	0	22,749	0	21
22	9,517	0	0	0	0	0	0	0	2,927	0	11,455	0	23,899	0	22
23	9,442	0	0	0	0	0	0	0	2,927	0	11,781	0	24,150	0	23
24	9,389	0	0	0	0	0	0	0	2,927	0	11,430	0	23,746	0	24
25	9,336	0	0	0	0	0	0	0	2,927	0	10,878	0	23,141	0	25
26	9,286	0	0	0	0	0	0	0	2,927	0	13,183	0	25,396	0	26
27	9,224	0	0	0	0	0	0	0	2,927	0	17,244	0	29,395	0	27
28	9,154	0	0	0	0	0	0	0	2,927	0	17,168	0	29,249	0	28
29	9,283	0	0	0	0	0	0	0	2,927	0	14,695	0	26,905	0	29
30	9,223	0	0	0	0	0	0	0	2,927	0	16,682	0	28,832	0	30
31	9,156	0	0	0	0	0	0	0	2,914	0	16,551	0	28,621	0	31
SUB-TOTALS	289,702	0	0	0	0	0	0	0	90,537	0	173,490	0	553,729	0	
SALES		0		10		0		28		0		0		38	
MCF	289,702	0	0	10	0	0	0	28	90,537	0	173,490	0	553,729	38	

Note: All volumes stated in MCF.

Attachme[illegible]R Item 90

WESTERN KENTUCKY GAS [illegible]PANY
UNDERGROUND STORAGE REPORT
June 1998

DAY	BON HARBOR FIELD IN	BON HARBOR FIELD OUT	HICKORY FIELD IN	HICKORY FIELD OUT	OWENSBORO FIELD IN	OWENSBORO FIELD OUT	GRANDVIEW FIELD IN	GRANDVIEW FIELD OUT	KIRKWOOD FIELD IN	KIRKWOOD FIELD OUT	St. CHARLES IN	St. CHARLES OUT	FIELD TOTALS IN	FIELD TOTALS OUT	DAY
1	11,200	0	0	0	0	0	0	0	0	0	15,880	0	27,080	0	1
2	12,353	0	0	0	0	0	0	0	0	0	15,508	0	27,861	0	2
3	12,427	0	0	0	0	0	0	0	0	0	14,981	0	27,408	0	3
4	11,670	0	0	0	0	0	0	0	0	0	9,070	0	20,740	0	4
5	12,493	0	0	0	0	0	0	0	0	0	12,051	0	24,544	0	5
6	12,536	0	0	0	0	0	0	0	0	0	13,671	0	26,207	0	6
7	3,978	0	0	0	0	0	0	0	0	0	13,331	0	17,309	0	7
8	0	0	0	0	0	0	252	0	0	0	11,669	0	11,921	0	8
9	0	0	0	0	0	0	4,133	0	0	0	11,695	0	15,828	0	9
10	0	0	0	0	0	0	3,880	0	0	0	7,272	0	11,152	0	10
11	0	0	0	0	0	0	3,710	0	0	0	9,497	0	13,207	0	11
12	0	0	0	0	0	0	3,696	0	0	0	11,762	0	15,458	0	12
13	0	0	0	0	0	0	3,578	0	0	0	12,495	0	16,073	0	13
14	0	0	0	0	0	0	3,441	0	0	0	12,120	0	15,561	0	14
15	0	0	0	0	0	0	3,271	0	0	0	11,579	0	14,850	0	15
16	0	0	0	0	0	0	3,131	0	0	0	11,280	0	14,411	0	16
17	0	0	0	0	0	0	3,537	0	0	0	10,881	0	14,418	0	17
18	0	0	0	0	0	0	3,511	0	0	0	10,160	0	13,671	0	18
19	0	0	0	0	0	0	3,404	0	0	0	10,392	0	13,796	0	19
20	0	0	0	0	0	0	3,330	0	0	0	10,415	0	13,745	0	20
21	0	0	0	0	0	0	3,485	0	0	0	9,963	0	13,448	0	21
22	0	0	0	0	0	0	3,419	0	0	0	9,224	0	12,643	0	22
23	0	0	0	0	0	0	3,486	0	0	0	8,009	0	11,495	0	23
24	0	0	0	0	0	0	3,370	0	0	0	11,263	0	14,633	0	24
25	0	0	0	0	0	0	3,292	0	0	0	11,125	0	14,417	0	25
26	0	0	0	0	0	0	3,211	0	0	0	10,873	0	14,084	0	26
27	0	0	0	0	0	0	3,100	0	0	0	10,632	0	13,732	0	27
28	0	0	0	0	0	0	3,025	0	0	0	10,372	0	13,397	0	28
29	0	0	0	0	0	0	2,965	0	0	0	9,958	0	12,923	0	29
30	0	0	0	0	0	0	2,906	0	0	0	9,808	0	12,714	0	30
31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31
SUB-TOTALS	76,657	0	0	0	0	0	75,133	0	0	0	336,936	0	488,726	0	
SALES		0		7		0		17		0		0		24	
MCF	76,657	0	0	7	0	0	75,133	17	0	0	336,936	0	488,726	24	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GA[illegible]MPANY
UNDERGROUND STORAG[illegible]EPORT
July 1998

DAY	BON HARBOR FIELD IN	BON HARBOR FIELD OUT	HICKORY FIELD IN	HICKORY FIELD OUT	OWENSBORO FIELD IN	OWENSBORO FIELD OUT	GRANDVIEW FIELD IN	GRANDVIEW FIELD OUT	KIRKWOOD FIELD IN	KIRKWOOD FIELD OUT	St. CHARLES IN	St. CHARLES OUT	FIELD TOTALS IN	FIELD TOTALS OUT	DAY
1	0	0	0	0	0	0	2,796	0	0	0	16,588	0	19,384	0	1
2	0	0	4,130	0	0	0	627	0	0	0	22,883	0	27,640	0	2
3	0	0	7,172	0	0	0	0	0	0	0	22,616	0	29,788	0	3
4	0	0	11,675	0	0	0	0	0	0	0	23,345	0	35,020	0	4
5	0	0	12,516	0	0	0	0	0	0	0	23,008	0	35,524	0	5
6	0	0	3,097	0	0	0	0	0	0	0	19,183	0	22,280	0	6
7	7,469	0	0	0	0	0	3,622	0	0	0	21,146	0	32,237	0	7
8	7,700	0	0	0	0	0	3,445	0	0	0	22,541	0	33,686	0	8
9	7,700	0	0	0	0	0	3,279	0	0	0	21,578	0	32,557	0	9
10	7,699	0	0	0	0	0	3,165	0	0	0	20,401	0	31,265	0	10
11	7,700	0	0	0	0	0	3,065	0	0	0	27,634	0	38,399	0	11
12	7,686	0	0	0	0	0	2,958	0	0	0	27,453	0	38,097	0	12
13	7,532	0	0	0	0	0	2,888	0	0	0	16,615	0	27,035	0	13
14	7,462	0	0	0	0	0	2,798	0	0	0	20,726	0	30,986	0	14
15	4,777	0	0	0	0	0	2,733	0	0	0	22,945	0	30,455	0	15
16	7,676	0	0	0	0	0	2,663	0	0	0	22,286	0	32,625	0	16
17	7,791	0	0	0	0	0	2,615	0	0	0	26,288	0	36,694	0	17
18	7,769	0	15,549	0	0	0	367	0	0	0	26,901	0	50,586	0	18
19	7,650	0	16,757	0	0	0	113	0	0	0	27,490	0	52,010	0	19
20	7,182	0	0	0	0	0	3,127	0	0	0	19,033	0	29,342	0	20
21	5,430	0	9,864	0	0	0	869	0	0	0	20,129	0	36,292	0	21
22	0	0	0	0	0	0	0	0	0	0	3,028	0	3,028	0	22
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	24
25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25
26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26
27	4	0	0	0	0	0	0	0	0	0	0	0	4	0	27
28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28
29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	29
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31
SUB-TOTALS	109,227	0	80,760	0	0	0	41,130	0	0	0	473,817	0	704,934	0	
SALES		0		7		0		15		0		0		22	
MCF	109,227	0	80,760	7	0	0	41,130	15	0	0	473,817	0	704,934	22	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GAS COMPANY
UNDERGROUND STORAGE REPORT
August 1998

	BON HARBOR FIELD		HICKORY FIELD		OWENSBORO FIELD		GRANDVIEW FIELD		KIRKWOOD FIELD		St. CHARLES		FIELD TOTALS		
DAY	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	DAY
1	0	0	0	0	0	0	3,124	0	0	0	15,773	0	18,897	0	1
2	0	0	0	0	0	0	2,887	0	0	0	15,993	0	18,880	0	2
3	0	0	0	0	0	0	2,759	0	0	0	14,535	0	17,294	0	3
4	0	0	0	0	0	0	2,614	0	0	0	15,750	0	18,364	0	4
5	10	0	0	0	0	0	2,485	0	0	0	15,630	0	18,125	0	5
6	0	0	0	0	0	0	2,403	0	0	0	15,574	0	17,977	0	6
7	25	0	0	0	0	0	2,358	0	0	0	16,655	0	19,038	0	7
8	4,800	0	0	0	0	0	2,247	0	0	0	17,642	0	24,689	0	8
9	4,800	0	0	0	0	0	2,185	0	0	0	17,402	0	24,387	0	9
10	4,800	0	9,375	0	0	0	237	0	0	0	20,016	0	34,428	0	10
11	37	0	9,160	0	0	0	0	0	0	0	19,546	0	28,743	0	11
12	4,713	0	8,009	0	0	0	0	0	0	0	17,985	0	30,707	0	12
13	4,750	0	7,187	0	0	0	0	0	0	0	20,811	0	32,748	0	13
14	4,735	0	4,351	0	0	0	0	0	0	0	20,208	0	29,294	0	14
15	4,745	0	12,072	0	0	0	0	0	0	0	21,280	0	38,097	0	15
16	4,750	0	12,614	0	0	0	0	0	0	0	21,731	0	39,095	0	16
17	4,750	0	1,077	0	0	0	0	0	0	0	18,273	0	24,100	0	17
18	4,750	0	932	0	0	0	0	0	0	0	20,447	0	26,129	0	18
19	4,750	0	0	0	0	0	0	0	0	0	17,832	0	22,582	0	19
20	1,575	0	2,831	0	0	0	0	0	0	0	491	0	4,897	0	20
21	0	0	0	0	0	0	0	0	0	0	4,327	0	4,327	0	21
22	1,689	0	1,772	0	0	0	0	0	0	0	4,693	0	8,154	0	22
23	82	0	4,949	0	0	0	0	0	0	0	3,951	0	8,982	0	23
24	0	0	0	0	0	0	0	0	0	0	270	0	270	0	24
25	0	0	1	0	0	0	0	0	0	0	3,585	0	3,586	0	25
26	3,826	0	4,431	0	0	0	0	0	0	0	3,775	0	12,032	0	26
27	4,800	0	11,719	0	0	0	0	0	0	0	3,441	0	19,960	0	27
28	4,800	0	7,387	0	0	0	0	0	0	0	3,524	0	15,711	0	28
29	4,800	0	8,977	0	0	0	0	0	0	0	4,798	0	18,575	0	29
30	4,797	0	10,511	0	0	0	0	0	0	0	11,176	0	26,484	0	30
31	683	0	1,434	0	0	0	0	0	0	0	15,866	0	17,983	0	31
SUB-TOTALS	79,467	0	118,789	0	0	0	23,299	0	0	0	402,980	0	624,535	0	
SALES		0		7		0		16		0		0		23	
MCF	79,467	0	118,789	7	0	0	23,299	16	0	0	402,980	0	624,535	23	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GA[illegible]OMPANY
UNDERGROUND STORA[illegible]EPORT
September 1998

DAY	BON HARBOR FIELD		HICKORY FIELD		OWENSBORO FIELD		GRANDVIEW FIELD		KIRKWOOD FIELD		St. CHARLES		FIELD TOTALS		DAY
	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	
1	0	0	0	0	0	0	0	0	0	0	2,337	0	2,337	0	1
2	0	0	0	6,201	0	0	0	0	0	0	0	0	0	6,201	2
3	0	0	0	6,422	0	0	0	0	0	0	0	0	0	6,422	3
4	0	0	0	0	0	0	0	0	0	0	2,205	0	2,205	0	4
5	6,419	0	6,871	0	0	0	0	0	0	0	3,900	0	17,190	0	5
6	2,383	0	3,165	0	0	0	0	0	0	0	16,244	0	21,792	0	6
7	0	0	0	0	0	0	0	0	0	0	16,892	0	16,892	0	7
8	0	0	0	0	0	0	0	0	0	0	14,805	0	14,805	0	8
9	0	0	0	0	0	0	0	0	0	0	15,968	0	15,968	0	9
10	0	0	0	0	0	0	0	0	0	0	4,180	0	4,180	0	10
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11
12	0	0	0	0	0	0	0	0	0	0	784	0	784	0	12
13	0	0	0	0	0	0	0	0	0	0	912	0	912	0	13
14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15
16	1,739	0	0	0	0	0	0	0	0	0	2,627	0	4,366	0	16
17	1,436	0	0	0	0	0	1,180	0	0	0	0	0	2,616	0	17
18	2,807	0	0	0	0	0	494	0	0	0	969	0	4,270	0	18
19	7	0	0	0	0	0	0	0	0	0	14,182	0	14,189	0	19
20	0	0	0	0	0	0	0	0	0	0	16,277	0	16,277	0	20
21	0	0	0	4,861	0	0	0	0	0	0	15,950	0	15,950	4,861	21
22	0	0	0	0	0	0	0	0	0	0	15,665	0	15,665	0	22
23	2,939	0	0	0	0	0	0	0	0	0	16,073	0	19,012	0	23
24	692	0	0	4,938	0	0	0	0	0	0	15,827	0	16,519	4,938	24
25	0	0	0	5,507	0	0	0	0	0	0	4,865	0	4,865	5,507	25
26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26
27	0	0	5,070	0	0	0	0	0	0	0	0	0	5,070	0	27
28	0	0	1,254	1,999	0	0	0	0	0	0	0	0	1,254	1,999	28
29	0	0	0	0	0	0	0	0	0	0	12,940	0	12,940	0	29
30	0	0	0	4,402	0	0	0	0	0	0	17,277	0	17,277	4,402	30
31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31
SUB-TOTALS	18,422	0	16,360	34,330	0	0	1,674	0	0	0	210,879	0	247,335	34,330	
SALES		0		7		0		253		0		0		260	
MCF	18,422	0	16,360	34,337	0	0	1,674	253	0	0	210,879	0	247,335	34,590	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GA[illegible]MPANY
UNDERGROUND STORAG[illegible]EPORT
October 1998

	BON HARBOR FIELD		HICKORY FIELD		OWENSBORO FIELD		GRANDVIEW FIELD		KIRKWOOD FIELD		St. CHARLES		FIELD TOTALS		
DAY	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	IN	OUT	DAY
1	2,457	0	0	2,197	0	0	0	0	0	0	17,007	0	19,464	2,197	1
2	628	0	0	205	0	0	0	0	0	0	17,011	0	17,639	205	2
3	0	0	9,804	0	0	0	0	0	0	0	17,294	0	27,098	0	3
4	0	0	12,625	0	0	0	0	0	0	0	17,102	0	29,727	0	4
5	0	0	4,132	0	0	0	0	0	0	0	13,443	0	17,575	0	5
6	0	0	614	0	0	0	0	0	0	0	13,501	0	14,115	0	6
7	0	0	983	0	0	0	0	0	0	0	13,494	0	14,477	0	7
8	0	0	889	3,867	0	0	0	0	3,814	0	12,308	0	17,011	3,867	8
9	0	0	0	4,678	0	0	0	0	3,902	0	3,171	0	7,073	4,678	9
10	0	0	0	0	0	0	0	0	3,902	0	12,796	0	16,698	0	10
11	0	0	0	0	0	0	0	0	3,902	0	16,085	0	19,987	0	11
12	0	0	0	0	0	0	0	0	3,851	0	3,472	0	7,323	0	12
13	0	0	0	0	0	0	0	0	3,850	0	0	0	3,850	0	13
14	722	0	0	362	0	0	0	0	3,850	0	0	0	4,572	362	14
15	0	0	0	439	0	0	0	0	3,850	0	0	0	3,850	439	15
16	3,172	0	0	0	0	0	0	0	3,850	0	1,208	0	8,230	0	16
17	6,031	0	0	0	0	0	0	0	13	4	13,072	0	19,116	4	17
18	5,392	0	0	0	0	0	0	0	0	0	13,322	0	18,714	0	18
19	523	0	0	4,772	0	0	0	0	0	0	743	33	1,266	4,805	19
20	0	0	0	5,142	0	0	0	0	0	0	0	0	0	5,142	20
21	0	0	0	7,479	0	0	0	0	0	0	0	1,187	0	8,666	21
22	0	0	0	6,973	0	0	0	0	0	0	0	6,885	0	13,858	22
23	0	0	0	5,352	0	0	0	0	0	0	0	9,444	0	14,796	23
24	4,366	0	0	0	0	0	0	0	0	0	0	0	4,366	0	24
25	6,668	0	4,297	0	0	0	0	0	0	0	0	1,845	10,965	1,845	25
26	365	0	0	0	0	0	0	0	0	0	0	8,050	365	8,050	26
27	2,483	0	0	0	0	0	0	0	0	0	0	0	2,483	0	27
28	0	0	0	0	0	0	0	0	0	0	7,630	0	7,630	0	28
29	0	0	9,722	0	0	0	0	0	0	0	8,011	0	17,733	0	29
30	6,719	0	12,912	0	0	0	3,756	0	0	0	16,619	0	40,006	0	30
31	7,532	0	7,776	0	0	0	3,548	0	0	0	19,855	0	38,711	0	31
SUB-TOTALS	47,058	0	63,754	41,466	0	0	7,304	0	34,784	4	237,144	27,444	390,044	68,914	
SALES		0		16		0		269		0		0		285	
MCF	47,058	0	63,754	41,482	0	0	7,304	269	34,784	4	237,144	27,444	390,044	69,199	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GAS COMPANY
UNDERGROUND STORAGE REPORT
November 1998

DAY	BON HARBOR FIELD IN	BON HARBOR FIELD OUT	HICKORY FIELD IN	HICKORY FIELD OUT	OWENSBORO FIELD IN	OWENSBORO FIELD OUT	GRANDVIEW FIELD IN	GRANDVIEW FIELD OUT	KIRKWOOD FIELD IN	KIRKWOOD FIELD OUT	St. CHARLES IN	St. CHARLES OUT	FIELD TOTALS IN	FIELD TOTALS OUT	DAY
1	0	0	7,530	0	0	0	3,402	0	0	0	717	0	11,649	0	1
2	0	0	2,099	0	0	0	921	0	0	0	0	0	3,020	0	2
3	0	0	0	15,157	0	0	0	0	0	0	0	1,029	0	16,186	3
4	0	6,793	0	15,583	0	0	0	0	0	0	0	18,354	0	40,730	4
5	0	8,126	0	14,667	0	0	0	0	0	0	0	19,009	0	41,802	5
6	0	9,475	0	13,110	0	0	0	0	0	0	0	18,711	0	41,296	6
7	0	5,456	0	6,861	0	0	0	0	0	0	0	12,489	0	24,806	7
8	0	7,576	0	548	0	0	0	0	0	0	0	12,129	0	20,253	8
9	0	1,403	0	9,045	0	0	0	0	0	0	0	3,553	0	14,001	9
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10
11	0	10,301	0	1,025	0	0	0	0	0	0	0	0	0	11,326	11
12	0	54	5,026	68	0	0	0	0	0	0	0	0	5,026	122	12
13	0	0	10,326	0	0	0	0	0	0	0	9,831	0	20,157	0	13
14	0	0	9,103	0	0	0	2,398	0	0	0	12,152	0	23,653	0	14
15	0	0	9,065	0	0	0	2,487	0	0	0	11,769	0	23,321	0	15
16	0	0	8,346	0	0	0	2,743	0	0	0	11,664	0	22,753	0	16
17	0	0	8,092	0	0	0	2,471	0	0	0	11,435	0	21,998	0	17
18	0	0	6,702	0	0	0	1,804	0	0	0	13,132	0	21,638	0	18
19	0	0	5,898	0	0	0	1,799	0	0	0	12,789	0	20,486	0	19
20	0	0	561	0	0	0	285	0	0	0	1,621	0	2,467	0	20
21	0	0	4,383	0	0	0	1,961	0	0	0	0	0	6,344	0	21
22	0	0	3,809	0	0	0	2,199	0	0	0	0	0	6,008	0	22
23	0	0	5,617	0	0	0	2,376	0	0	0	9,680	0	17,673	0	23
24	0	0	5,073	0	0	0	2,327	0	0	0	11,767	0	19,167	0	24
25	0	0	4,539	0	0	0	2,218	0	0	0	11,944	0	18,701	0	25
26	0	0	4,225	0	0	0	0	0	0	0	13,592	0	17,817	0	26
27	0	0	3,756	0	0	0	0	0	0	0	13,504	0	17,260	0	27
28	0	0	3,615	0	0	0	0	0	0	0	13,136	0	16,751	0	28
29	0	0	3,279	0	0	0	0	0	0	0	0	0	3,279	0	29
30	0	0	0	1,660	0	0	1,632	0	0	0	0	0	1,632	1,660	30
31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31
SUB-TOTALS	0	49,184	111,044	77,724	0	0	31,023	0	0	0	158,733	85,274	300,800	212,182	
SALES		0		33		0		77		0		0		110	
MCF	0	49,184	111,044	77,757	0	0	31,023	77	0	0	158,733	85,274	300,800	212,292	

Note: All volumes stated in MCF.

WESTERN KENTUCKY GA[illegible]MPANY
UNDERGROUND STORAG[illegible]EPORT
December 1998

DAY	BON HARBOR FIELD IN	BON HARBOR FIELD OUT	HICKORY FIELD IN	HICKORY FIELD OUT	OWENSBORO FIELD IN	OWENSBORO FIELD OUT	GRANDVIEW FIELD IN	GRANDVIEW FIELD OUT	KIRKWOOD FIELD IN	KIRKWOOD FIELD OUT	St. CHARLES IN	St. CHARLES OUT	FIELD TOTALS IN	FIELD TOTALS OUT	DAY
1	0	0	0	1,518	0	0	1,492	0	0	0	0	0	1,492	1,518	1
2	0	0	0	1,327	0	0	1,348	0	0	0	0	0	1,348	1,327	2
3	0	0	0	1,209	0	0	1,184	0	0	0	0	0	1,184	1,209	3
4	0	0	0	111	0	0	0	0	0	0	0	0	0	111	4
5	0	0	0	17	0	0	0	0	0	0	0	0	0	17	5
6	0	0	2	65	0	0	0	1	0	0	0	0	2	66	6
7	0	0	0	265	0	0	0	0	0	0	0	716	0	981	7
8	0	9,143	0	13,546	0	0	0	0	0	0	0	19,658	0	42,347	8
9	0	7,354	0	11,095	0	0	0	0	0	0	0	17,530	0	35,979	9
10	0	5,282	0	7,259	0	0	0	0	0	0	0	13,737	0	26,278	10
11	0	2,788	0	3,022	0	0	0	0	0	0	0	2,424	0	8,234	11
12	0	0	0	260	0	0	0	0	0	0	0	0	0	260	12
13	0	2,771	0	101	0	0	0	0	0	0	0	208	0	3,080	13
14	0	6,952	0	9,988	0	0	0	0	0	0	0	10,375	0	27,315	14
15	0	6,327	0	848	0	0	0	0	0	0	0	15,861	0	23,036	15
16	0	15,000	0	12,642	0	0	0	0	0	0	0	19,196	0	46,838	16
17	0	15,004	0	15,001	0	0	0	0	0	0	0	22,568	0	52,573	17
18	0	13,021	0	7,952	0	0	0	0	0	0	0	17,814	0	38,787	18
19	0	7,484	0	2,280	0	0	0	0	0	0	0	14,793	0	24,557	19
20	0	0		0	0	0	21	1	0	0	0	6,795	21	6,796	20
21	0	10,230	0	0	0	0	0	492	0	346	0	18,831	0	29,899	21
22	0	18,757	0	15,954	0	0	0	2,810	0	5,057	0	26,898	0	69,476	22
23	0	18,464	0	14,685	0	0	0	3,912	0	2,013	0	25,884	0	64,958	23
24	0	3,693	0	1,051	0	0	0	557	0	0	0	8,191	0	13,492	24
25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25
26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26
27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27
28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28
29	0	0	0	1	0	0	0	319	0	0	0	1,158	0	1,478	29
30	0	0	0	0	0	0	0	753	0	0	0	18,566	0	19,319	30
31	0	365	0	0	0	0	0	0	0	0	0	673	0	1,038	31
SUB-TOTALS	0	142,635	2	120,197	0	0	4,045	8,845	0	7,416	0	261,876	4,047	540,969	
SALES		0		57		0		105		0		0		162	
MCF	0	142,635	2	120,254	0	0	4,045	8,950	0	7,416	0	261,876	4,047	541,131	

Note: All volumes stated in MCF.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 91
Witness: Thomas H. Petersen

Data Request:

Reference FR 10(9)(v), page 5. Please describe the $2,009,995 "Other" plant on line 19. Indicate the accounts that house this plant.

Response:

The $2,009,995 "Other" plant on line 19 is an allocated portion of the $97,572,577 Distribution portion of rate base from line 22 of column (d) of page 3. The allocation to the category is on page 4 and is based on the percent of total distribution plant from line 21 of column (e) of sheet 4. The $2,009,995 is attributed to account 381.20 Gauges and 385.00 Industrial Measuring and Regulating Station Equipment.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 92
Witness: Thomas H. Petersen

Data Request:

Reference FR 10(9)(v), page 6. Please describe the $332,431 A&G, line 3. Indicate the accounts that house this expense.

Response:

The $332,431 A&G amount on line 3 is an allocated portion of total administrative and general expenses. The allocation is shown on line 14 of Sheet 1 and described in footnote 2 to that sheet. The accounts included in the $332,431 are 920 through 932.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 93
Witness: Thomas H. Petersen

Data Request:

Reference FR 10(9)(v), pages 10, 11, 12 and 13. Please provide workpapers showing the derivation of the 2 percent, 98 percent, 64 percent, and 36 percent splits in the various accounts. Explain why the referenced percents are utilized.

Response:

Customer accounts and services expenses on line 2 of page 10 requires functionalization to distribution or transmission in Western's class cost of service study. Therefore, the percentage on line 2 divides these expenses between distribution and transmission functions. Note that both distribution and transmission portions of these expenses are allocated among rate classes by the same allocation factor, Cust-B. Sales expenses on line 3 of page 10 requires functionalization to distribution or transmission in Western's class cost of service study. The percentage on line 3 divides these expenses between distribution and transmission functions. Note that both distribution and transmission portions of these expenses are allocated among rate classes by the same allocation factor, Vol-A. The expenses on line 5 of page 10 are related to services, meters, customer installation expenses etc. The percentage on line 5 divides these expenses between distribution and transmission functions. Note that both distribution and transmission portions of these expenses are allocated among rate classes by the same allocation factor, Cust-B.

The 98 percent and 64 percent factors used on page 10 to divide these amounts between distribution and transmission functions were selected based on the judgement of company personnel. No formal workpapers were prepared.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 94
Witness: Thomas H. Petersen

Data Request:

Wherever the Design Day Factor B is utilized in total on in part (as with the P&A factor), please explain why the Design B factor is believed to be appropriate and why the Design A factor was not used.

Response:

The Design-B factor is used to calculate the average and peak allocators, A&P and A&P/Gas. These allocators were developed in response to the Commissions suggestions in its orders in Western's Case No. 9556 and Administrative Case No. 297 that some consideration be given to volume of use in allocating demand costs. The Commission recommended consideration of a peak and average method of cost allocation. The Company uses a method comparable to the A&P/Gas allocator to apportion gas non-commodity costs between firm and interruptible service in its GCA process. This method reflects that the level of non-commodity costs is determined by design day requirements when interruptible service is curtailed and that interruptible customers benefit from Western's supply arrangements paid for by non-commodity charges when they use capacity and supply purchased under those arrangements. Consistent with this GCA treatment, administrative and general costs assigned to the gas cost function are allocated using the A&P/Gas allocator. Similarly demand costs in the production and transmission functions are allocated using the A&P allocator.

Since the average and peak allocators are intended to represent a combination of average annual usage levels and peak day requirements, the Design-B allocator which is based on the peak day used for supply planning is more appropriate to include than the Design-A allocator which is based on non-coincident peak and maximum daily contract levels.

The Design-B factor is also used to allocate the demand portion of storage costs. The storage function enhances service throughout the winter season and helps to meet peak day demands. Some of storage costs are classified as commodity related and allocated based on winter season volumes. Other storage costs are classified as demand related and are allocated based on peak day requirements by use of the Design-B factor.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 95
Witness: Thomas H. Petersen

Data Request:

Reference FR 10(9)(v), page 19. Please indicate the sources of numbers that total to each individual cost shown in column (a).

Response:

The O&M Expense on line 1 of column (a) of page 19 is the sum of the amounts on lines 1, 3, 7, 11 and 14 of column (b) on page 11 and lines 3 and 10 of column (b) on page 13. The Depreciation and Amortization on line 3 of column (a) of page 19 is the sum of the amounts on lines 17 and 19 of column (b) of page 11. The Property and Other Taxes on line 5 of column (a) of page 19 is the sum of the amounts on lines 21 and 23 of column (b) of page 11. The Income Taxes on line 7 of column (a) of page 19 is the sum of the amounts on lines 29 and 31 of column (b) of page 11. The Return on line 9 of column (a) of page 19 is the sum of the amounts on lines 25 and 27 of column (b) of page 11.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 96
Witness: Thomas H. Petersen

Data Request:

It appears that the Distribution Mains investment is classified customer/demand on the basis of the reported "Regression Minimum" zero-intercept results reported on Sheet 7 of 9 on schedules following your filed class cost of service study. Please confirm this understanding, or explain the basis of your distribution mains customer/demand split, if this understanding is not correct. Provide workpapers if the C/D split is other than as understood and explained herein.

Response:

The distribution mains investment is classified customer/demand on the basis of the regression minimum zero-intercept analysis on Sheet 7 of the class cost of service study.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 97
Witness: Smith

Data Request:

Reference page 10, lines 23-27, of Mr. Smith's testimony. Please provide the analysis performed by the Company to determine the appropriate weights for each station.

Response:

See attached Determination of NOAA Weather Station Weightings, pages 1-3.

WESTERN KENTUCKY GAS COMPANY
Determination of NOAA Weather Station Weightings

Dec-98 Data	Domestic	Commercial	Public Authority	Total
Louisville				
Shelbyville	4285	534	38	4,857
Total Louisville				4,857
Nashville				
Glasgow	4731	714	61	5,506
Bowling Green	18275	2125	171	20,571
Russellville	2830	409	33	3,272
Adairville	374	40	7	421
Franklin	3272	368	29	3,669
Auburn	456	59	6	521
Woodburn	171	15	2	188
Cave City	643	124	5	772
Hiseville	99	14	2	115
Horse Cave	822	99	8	929
Munfordville	469	102	13	584
Oakland	77	8	3	88
Park City	179	25	2	206
Smith's Grove	270	50	4	324
Total Nashville				37,166
Lexington				
Lawrenceburg	3140	230	34	3,404
Harrodsburg	2919	380	47	3,346
Campbellsville	4860	541	40	5,441
Lebanon	1991	298	50	2,339
Perryville	315	38	7	360
Lancaster	1215	138	24	1,377
Burgin	323	25	5	353
Springfield	944	179	22	1,145
Greensburg	864	140	26	1,030
Stanford	1000	168	26	1,194
Junction City	1035	62	6	1,103
Hustonville	350	35	5	390
Danville	4812	708	54	5,574
Total Lexington				27,056

Evansville				
Owensboro	27145	2409	135	29,689
Beaver Dam	1176	148	8	1,332
Calhoun	391	71	16	478
Cloverport	379	26	10	415
Fordsville	357	46	5	408
Hartford	1298	133	13	1,444
Hawesville	409	54	16	479
Whitesville	446	35	6	487
Hanson	223	21	4	248
Sebree	1578	127	15	1,720
Dixon	267	37	15	319
Slaughters	109	14	4	127
Henderson	351	5	0	356
Hardinsburg	839	158	22	1,019
Total Evansville				38,521
Paducah				
Eddyville	314	81	14	409
Princeton	2696	318	28	3,042
Dawson Springs	1021	111	13	1,145
Cadiz	942	179	28	1,149
Marion	1106	163	22	1,291
Fredonia	185	25	3	213
Hopkinsville	10431	1118	73	11,622
Elkton	658	138	16	812
Crofton	314	37	5	356
Greenville	1808	203	40	2,051
Central City	2080	291	27	2,398
Bremen	415	28	6	449
Sacramento	304	36	4	344
Paducah	19058	2096	118	21,272
Calvert City	771	120	8	899
Gilbertsville	160	3	1	164
Grand Rivers	437	73	5	515
Mayfield	5762	712	53	6,527
Water Valley	129	9	3	141
Wingo	320	24	4	348
Madisonville	7925	926	85	8,936
Earlington	637	29	3	669
Morton's Gap	342	25	1	368
Nortonville	508	38	5	551
St.Charles	59	4	2	65
Total Paducah				65,736
Total	154071	17699	1566	173,336

NOAA Station						Weightings
Louisville				4,857	0.02802	**0.028**
Nashville				37,166	0.21442	**0.215**
Lexington				27,056	0.15609	**0.156**
Evansville				38,521	0.22223	**0.222**
Paducah				65,736	0.37924	**0.379**
Total Kentucky	154071	17699	1566	173,336	1.00000	**1.000**

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 98
Witness: Smith

Data Request:

Reference page 10, line 29 through page 11, line 2 of Mr. Smith's testimony. Please provide a copy of the referenced report for each of the five stations listed on page 10, lines 23-27.

Response:

See attached NOAA Report on "Climatography of the United States No. 84, Daily Normals of Temperature, Heating and Cooling Degree Days, and Precipitation 1961-90" for the Evansville, Nashville, Lexington, Louisville and Paducah NOAA weather stations.

CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

122738 EVANSVILLE WSO AP LATITUDE: 38 03N LONGITUDE: 087 32W ELEVATION: 380 FT.

DAILY	DECEMBER TEMPERATURE MAX	DECEMBER TEMPERATURE MIN	DECEMBER TEMPERATURE AVG	DECEMBER DEG HDD	DECEMBER DAY CDD	DECEMBER PCP	JANUARY TEMPERATURE MAX	JANUARY TEMPERATURE MIN	JANUARY TEMPERATURE AVG	JANUARY DEG HDD	JANUARY DAY CDD	JANUARY PCP	FEBRUARY TEMPERATURE MAX	FEBRUARY TEMPERATURE MIN	FEBRUARY TEMPERATURE AVG	FEBRUARY DEG HDD	FEBRUARY DAY CDD	FEBRUARY PCP
1	49	32	40	25	0	.13	40	22	31	34	0	.10	40	22	31	34	0	.09
2	48	31	40	25	0	.13	39	22	31	34	0	.10	40	22	31	34	0	.09
3	48	31	39	26	0	.13	39	22	31	34	0	.09	40	22	31	34	0	.09
4	48	30	39	26	0	.13	39	22	30	35	0	.09	41	22	31	34	0	.09
5	47	30	39	26	0	.13	39	22	30	35	0	.09	41	22	32	33	0	.10
6	47	30	38	27	0	.13	39	22	30	35	0	.09	41	23	32	33	0	.10
7	46	29	38	27	0	.13	39	21	30	35	0	.09	41	23	32	33	0	.10
8	46	29	38	27	0	.13	39	21	30	35	0	.09	41	23	32	33	0	.10
9	46	29	37	28	0	.13	39	21	30	35	0	.09	42	23	32	33	0	.10
10	45	28	37	28	0	.13	39	21	30	35	0	.09	42	23	33	32	0	.10
11	45	28	36	29	0	.12	39	21	30	35	0	.09	42	24	33	32	0	.10
12	44	28	36	29	0	.12	39	21	30	35	0	.08	43	24	33	32	0	.11
13	44	27	36	29	0	.12	38	21	30	35	0	.08	43	24	34	31	0	.11
14	44	27	36	29	0	.12	38	21	30	35	0	.08	43	25	34	31	0	.11
15	44	27	35	30	0	.12	38	21	30	35	0	.08	43	25	34	31	0	.11
16	43	26	35	30	0	.12	38	21	30	35	0	.08	44	25	35	30	0	.11
17	43	26	35	30	0	.12	38	21	29	36	0	.08	44	25	35	30	0	.11
18	43	26	34	31	0	.12	38	21	30	35	0	.08	45	26	35	30	0	.12
19	42	26	34	31	0	.12	39	21	30	35	0	.08	45	26	36	29	0	.12
20	42	25	34	31	0	.12	39	21	30	35	0	.08	45	26	36	29	0	.12
21	42	25	33	32	0	.11	39	21	30	35	0	.08	46	27	36	29	0	.12
22	42	25	33	32	0	.11	39	21	30	35	0	.08	46	27	37	28	0	.12
23	41	25	33	32	0	.11	39	21	30	35	0	.08	47	27	37	28	0	.13
24	41	24	33	32	0	.11	39	21	30	35	0	.08	47	28	37	28	0	.13
25	41	24	33	32	0	.11	39	21	30	35	0	.08	47	28	38	27	0	.13
26	41	24	32	33	0	.11	39	21	30	35	0	.08	48	29	38	27	0	.13
27	40	24	32	33	0	.11	39	21	30	35	0	.09	48	29	39	26	0	.14
28	40	23	32	33	0	.10	39	21	30	35	0	.09	49	30	39	26	0	.14
29	40	23	32	33	0	.10	39	21	30	35	0	.09						
30	40	23	31	34	0	.10	40	21	30	35	0	.09						
31	40	23	31	34	0	.10	40	21	31	34	0	.09						
MONTHLY	43.6	26.7	35.2	924	0	3.67	38.9	21.2	30.1	1082	0	2.66	43.7	25.0	34.4	857	0	3.12
WINTER	42.1	24.3	33.2	2863	0	9.45												
ANNUAL	66.3	45.2	55.8	4708	1376	43.14												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

122738 EVANSVILLE WSO AP   LATITUDE: 38 03N   LONGITUDE: 087 32W   ELEVATION: 380 FT.

DAILY	MARCH						APRIL						MAY					
	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	49	30	40	25	0	.14	62	41	52	13	0	.14	72	50	61	6	2	.15
2	50	30	40	25	0	.14	63	41	52	13	0	.14	73	50	61	6	2	.15
3	50	31	41	24	0	.14	63	41	52	13	0	.14	73	50	61	6	2	.15
4	51	31	41	24	0	.14	64	42	53	12	0	.14	73	50	62	5	2	.15
5	51	32	41	24	0	.15	64	42	53	12	0	.14	73	51	62	5	2	.15
6	52	32	42	23	0	.15	64	42	53	12	0	.13	74	51	62	5	2	.15
7	52	33	42	23	0	.15	65	43	54	11	0	.13	74	51	63	5	3	.16
8	52	33	43	22	0	.15	65	43	54	11	0	.13	74	52	63	5	3	.16
9	53	33	43	22	0	.15	65	43	54	11	0	.13	75	52	63	5	3	.16
10	53	34	44	21	0	.15	66	43	55	10	0	.13	75	52	64	4	3	.16
11	54	34	44	21	0	.15	66	44	55	10	0	.13	75	53	64	4	3	.16
12	54	34	44	21	0	.16	66	44	55	10	0	.13	76	53	64	4	3	.16
13	55	35	45	20	0	.16	67	44	55	10	0	.13	76	53	65	4	4	.16
14	55	35	45	20	0	.16	67	45	56	9	0	.13	76	54	65	4	4	.16
15	56	36	46	19	0	.16	67	45	56	9	0	.13	76	54	65	4	4	.16
16	56	36	46	19	0	.16	68	45	56	9	0	.13	77	54	65	4	4	.16
17	56	36	46	19	0	.16	68	45	57	8	0	.13	77	54	65	4	4	.16
18	57	37	47	18	0	.16	68	46	57	8	0	.13	77	55	66	3	4	.16
19	57	37	47	18	0	.16	69	46	57	8	0	.13	78	55	66	3	4	.16
20	58	37	47	18	0	.16	69	46	58	7	0	.13	78	55	67	3	5	.16
21	58	38	48	17	0	.16	69	47	58	7	0	.13	78	56	67	3	5	.15
22	59	38	48	17	0	.16	70	47	59	7	1	.13	79	56	67	3	5	.15
23	59	38	49	16	0	.15	70	47	59	7	1	.13	79	56	68	3	6	.15
24	59	39	49	16	0	.15	70	47	59	7	1	.13	79	57	68	3	6	.15
25	60	39	49	16	0	.15	70	48	59	7	1	.14	80	57	69	2	6	.15
26	60	39	50	15	0	.15	71	48	59	7	1	.14	80	57	69	2	6	.15
27	61	39	50	15	0	.15	71	48	59	7	1	.14	81	58	69	2	6	.15
28	61	40	50	15	0	.15	71	49	60	6	1	.14	81	58	69	2	6	.14
29	61	40	51	14	0	.15	72	49	60	6	1	.14	81	58	70	2	7	.14
30	62	40	51	14	0	.15	72	49	60	6	1	.15	82	59	70	2	7	.14
31	62	41	51	14	0	.14							82	59	71	1	7	.14
MONTHLY	55.9	35.7	45.8	595	0	4.71	67.4	45.0	56.2	273	9	4.02	76.9	54.2	65.5	114	130	4.75
SPRING	66.8	45.0	55.9	982	139	13.48												
ANNUAL	66.3	45.2	55.8	4708	1376	43.14												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

122738 EVANSVILLE WSO AP LATITUDE: 38 03N LONGITUDE: 087 32W ELEVATION: 380 FT.

DAILY	JUNE TEMPERATURE MAX	MIN	AVG	DEG DAY HDD	CDD	PCP	JULY TEMPERATURE MAX	MIN	AVG	DEG DAY HDD	CDD	PCP	AUGUST TEMPERATURE MAX	MIN	AVG	DEG DAY HDD	CDD	PCP
1	83	60	72	0	7	.13	89	66	78	0	13	.12	89	67	78	0	13	.12
2	83	60	72	0	7	.13	89	67	78	0	13	.12	89	67	78	0	13	.12
3	83	60	72	0	7	.13	89	67	78	0	13	.13	89	67	78	0	13	.11
4	83	60	72	0	7	.13	89	67	78	0	13	.13	89	67	78	0	13	.11
5	84	61	72	0	7	.12	89	67	78	0	13	.13	89	67	78	0	13	.11
6	84	61	73	0	8	.12	89	67	78	0	13	.13	88	66	77	0	12	.11
7	84	61	73	0	8	.12	89	67	78	0	13	.13	88	66	77	0	12	.11
8	85	62	73	0	8	.12	89	67	78	0	13	.13	88	66	77	0	12	.11
9	85	62	73	0	8	.12	89	67	78	0	13	.13	88	66	77	0	12	.10
10	85	62	74	0	9	.12	89	67	78	0	13	.13	88	66	77	0	12	.10
11	86	62	74	0	9	.11	89	68	78	0	13	.13	88	66	77	0	12	.10
12	86	63	74	0	9	.11	89	68	79	0	14	.13	88	66	77	0	12	.10
13	86	63	74	0	9	.11	89	68	79	0	14	.14	88	65	77	0	12	.10
14	86	63	75	0	10	.11	89	68	79	0	14	.14	88	65	77	0	12	.10
15	86	63	75	0	10	.11	89	68	79	0	14	.14	88	65	76	0	11	.10
16	87	64	75	0	10	.11	90	68	79	0	14	.14	87	65	76	0	11	.10
17	87	64	75	0	10	.11	90	68	79	0	14	.14	87	65	76	0	11	.10
18	87	64	76	0	11	.11	90	68	79	0	14	.14	87	65	76	0	11	.10
19	87	64	76	0	11	.11	89	68	79	0	14	.13	87	65	76	0	11	.10
20	87	65	76	0	11	.11	89	68	79	0	14	.13	87	64	76	0	11	.09
21	88	65	76	0	11	.11	89	68	79	0	14	.13	87	64	75	0	10	.09
22	88	65	76	0	11	.11	89	68	79	0	14	.13	86	64	75	0	10	.09
23	88	65	77	0	12	.11	89	68	79	0	14	.13	86	64	75	0	10	.09
24	88	65	77	0	12	.11	89	68	78	0	13	.13	86	64	75	0	10	.09
25	88	66	77	0	12	.11	89	68	78	0	13	.13	86	63	75	0	10	.09
26	88	66	77	0	12	.12	89	68	78	0	13	.13	86	63	75	0	10	.09
27	88	66	77	0	12	.12	89	67	78	0	13	.13	86	63	74	0	9	.09
28	89	66	77	0	12	.12	89	67	78	0	13	.13	85	63	74	0	9	.09
29	89	66	77	0	12	.12	89	67	78	0	13	.12	85	63	74	0	9	.10
30	89	66	77	0	12	.12	89	67	78	0	13	.12	85	63	74	0	9	.10
31							89	67	78	0	13	.12	85	62	74	0	9	.10
MONTHLY	86.2	63.3	74.8	0	294	3.49	89.1	67.5	78.4	0	415	4.04	87.2	64.9	76.1	0	344	3.11
SUMMER	87.6	65.3	76.5	0	1053	10.64												
ANNUAL	66.3	45.2	55.8	4708	1376	43.14												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F: TEMPERATURE UNITS = DEG F:
PRECIPITATION UNITS = INCHES: * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

122738 EVANSVILLE WSO AP LATITUDE: 38 03N LONGITUDE: 087 32W ELEVATION: 380 FT.

	SEPTEMBER						OCTOBER						NOVEMBER					
	TEMPERATURE			DEG	DAY		TEMPERATURE			DEG	DAY		TEMPERATURE			DEG	DAY	
DAILY	MAX	MIN	AVG	HDD	CDD	PCP	MAX	MIN	AVG	HDD	CDD	PCP	MAX	MIN	AVG	HDD	CDD	PCP
1	85	62	73	0	8	.10	76	51	64	4	3	.09	63	40	51	14	0	.11
2	84	62	73	0	8	.10	75	50	63	4	2	.09	62	40	51	14	0	.11
3	84	62	73	0	8	.10	75	50	62	5	2	.09	62	40	51	14	0	.11
4	84	62	73	0	8	.10	75	49	62	5	2	.09	61	40	50	15	0	.11
5	84	61	73	0	8	.10	74	49	62	5	2	.09	61	39	50	15	0	.11
6	83	61	72	0	7	.10	74	48	61	6	2	.09	60	39	50	15	0	.12
7	83	61	72	0	7	.10	73	48	61	6	2	.09	60	39	49	16	0	.12
8	83	60	72	0	7	.10	73	47	60	6	1	.09	59	39	49	16	0	.12
9	83	60	71	0	6	.10	73	47	60	6	1	.09	59	38	49	16	0	.12
10	82	60	71	0	6	.10	72	47	59	7	1	.09	58	38	48	17	0	.12
11	82	60	71	0	6	.10	72	46	59	7	1	.09	58	38	48	17	0	.12
12	82	59	71	0	6	.10	71	46	59	7	1	.09	57	38	48	17	0	.12
13	82	59	70	1	6	.10	71	45	58	8	1	.09	57	37	47	18	0	.13
14	81	59	70	1	6	.10	71	45	58	8	1	.09	57	37	47	18	0	.13
15	81	58	70	1	6	.10	70	45	57	9	1	.09	56	37	47	18	0	.13
16	81	58	69	1	5	.10	70	44	57	9	1	.09	56	37	46	19	0	.13
17	80	57	69	1	5	.10	69	44	57	9	1	.09	55	36	46	19	0	.13
18	80	57	69	1	5	.10	69	44	56	9	0	.09	55	36	45	20	0	.13
19	80	57	68	1	4	.10	68	43	56	9	0	.09	54	36	45	20	0	.13
20	80	56	68	1	4	.10	68	43	56	9	0	.09	54	35	45	20	0	.13
21	79	56	68	1	4	.10	68	43	55	10	0	.09	53	35	44	21	0	.13
22	79	55	67	2	4	.10	67	42	55	10	0	.09	53	35	44	21	0	.13
23	79	55	67	2	4	.10	67	42	54	11	0	.09	52	35	43	22	0	.13
24	78	54	66	2	3	.10	66	42	54	11	0	.09	52	34	43	22	0	.13
25	78	54	66	2	3	.10	66	42	54	11	0	.10	52	34	43	22	0	.13
26	78	54	66	2	3	.10	65	41	53	12	0	.10	51	33	42	23	0	.13
27	77	53	65	3	3	.10	65	41	53	12	0	.10	51	33	42	23	0	.13
28	77	53	65	3	3	.09	64	41	53	12	0	.10	50	33	41	24	0	.13
29	76	52	64	4	3	.09	64	41	52	13	0	.10	50	32	41	24	0	.13
30	76	51	64	4	3	.09	64	40	52	13	0	.10	49	32	41	24	0	.13
31							63	40	52	13	0	.11						
MONTHLY	80.7	57.6	69.2	33	159	2.97	69.6	44.7	57.2	266	25	2.87	55.9	36.5	46.2	564	0	3.73
AUTUMN	68.8	46.3	57.6	863	184	9.57												
ANNUAL	66.3	45.2	55.8	4708	1376	43.14												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

406402 NASHVILLE WSO AP   LATITUDE: 36 07N   LONGITUDE: 086 41W   ELEVATION: 580 FT.

	DECEMBER						JANUARY						FEBRUARY					
DAILY	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	55	35	45	20	0	.16	47	28	37	28	0	.13	47	27	37	28	0	.12
2	54	35	44	21	0	.16	46	27	37	28	0	.13	47	27	37	28	0	.12
3	54	34	44	21	0	.16	46	27	37	28	0	.13	48	27	38	27	0	.12
4	54	34	44	21	0	.16	46	27	36	29	0	.12	48	27	38	27	0	.12
5	53	34	43	22	0	.16	46	27	36	29	0	.12	48	28	38	27	0	.12
6	53	33	43	22	0	.16	46	27	36	29	0	.12	48	28	38	27	0	.13
7	53	33	43	22	0	.16	46	27	36	29	0	.12	49	28	38	27	0	.13
8	52	33	42	23	0	.16	46	27	36	29	0	.12	49	28	39	26	0	.13
9	52	33	42	23	0	.16	46	27	36	29	0	.12	49	28	39	26	0	.13
10	52	32	42	23	0	.15	46	26	36	29	0	.12	49	29	39	26	0	.13
11	51	32	42	23	0	.15	46	26	36	29	0	.11	50	29	39	26	0	.13
12	51	32	41	24	0	.15	45	26	36	29	0	.11	50	29	39	26	0	.13
13	51	31	41	24	0	.15	45	26	36	29	0	.11	50	29	40	25	0	.13
14	50	31	41	24	0	.15	45	26	36	29	0	.11	50	30	40	25	0	.14
15	50	31	41	24	0	.15	45	26	36	29	0	.11	51	30	40	25	0	.14
16	50	31	40	25	0	.15	45	26	36	29	0	.11	51	30	41	24	0	.14
17	50	30	40	25	0	.15	45	26	36	29	0	.11	51	30	41	24	0	.14
18	49	30	40	25	0	.15	45	26	36	29	0	.11	52	31	41	24	0	.14
19	49	30	40	25	0	.15	46	26	36	29	0	.11	52	31	41	24	0	.14
20	49	30	39	26	0	.15	46	26	36	29	0	.11	52	31	42	23	0	.14
21	49	30	39	26	0	.15	46	26	36	29	0	.11	53	31	42	23	0	.14
22	48	29	39	26	0	.14	46	26	36	29	0	.11	53	32	42	23	0	.15
23	48	29	39	26	0	.14	46	26	36	29	0	.11	53	32	43	22	0	.15
24	48	29	38	27	0	.14	46	26	36	29	0	.11	54	32	43	22	0	.15
25	48	29	38	27	0	.14	46	26	36	29	0	.11	54	33	43	22	0	.15
26	48	28	38	27	0	.14	46	26	36	29	0	.11	54	33	44	21	0	.15
27	47	28	38	27	0	.14	46	27	36	29	0	.11	55	33	44	21	0	.15
28	47	28	38	27	0	.14	46	27	36	29	0	.12	55	34	45	20	0	.15
29	47	28	37	28	0	.13	47	27	37	28	0	.12						
30	47	28	37	28	0	.13	47	27	37	28	0	.12						
31	47	28	37	28	0	.13	47	27	37	28	0	.12						
MONTHLY	50.2	30.9	40.5	760	0	4.61	45.9	26.5	36.2	893	0	3.58	50.8	29.9	40.4	689	0	3.81
WINTER	49.0	29.1	39.0	2342	0	12.00												
ANNUAL	69.8	48.4	59.1	3729	1616	47.30												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

406402 NASHVILLE WSO AP — LATITUDE: 36 07N — LONGITUDE: 086 41W — ELEVATION: 580 FT.

	MARCH						APRIL						MAY					
DAILY	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP
1	56	34	45	20	0	.15	67	44	55	10	0	.15	75	52	63	4	2	.16
2	56	35	45	20	0	.15	67	44	55	10	0	.15	75	52	64	3	2	.16
3	56	35	46	19	0	.15	67	44	56	9	0	.15	75	53	64	3	2	.16
4	57	35	46	19	0	.15	68	44	56	9	0	.15	76	53	64	3	2	.16
5	57	36	46	19	0	.16	68	45	56	9	0	.15	76	53	65	3	3	.16
6	58	36	47	18	0	.16	68	45	57	8	0	.15	76	54	65	3	3	.16
7	58	36	47	18	0	.16	68	45	57	8	0	.14	76	54	65	3	3	.16
8	58	37	48	17	0	.16	69	45	57	8	0	.14	77	54	65	3	3	.16
9	59	37	48	17	0	.16	69	46	57	8	0	.14	77	55	66	2	3	.16
10	59	37	48	17	0	.16	69	46	58	7	0	.14	77	55	66	2	3	.16
11	60	38	49	17	1	.16	70	46	58	7	0	.14	77	55	66	2	3	.16
12	60	38	49	17	1	.16	70	46	58	7	0	.14	78	55	67	2	4	.17
13	60	38	49	17	1	.16	70	47	58	7	0	.14	78	56	67	2	4	.16
14	61	39	50	16	1	.16	70	47	59	6	0	.14	78	56	67	2	4	.16
15	61	39	50	16	1	.16	71	47	59	6	0	.14	78	56	67	2	4	.16
16	61	39	50	16	1	.16	71	48	60	6	1	.14	79	57	68	2	5	.16
17	62	40	51	15	1	.16	71	48	60	6	1	.14	79	57	68	2	5	.16
18	62	40	51	15	1	.16	72	48	60	6	1	.14	79	57	68	2	5	.16
19	62	40	51	15	1	.16	72	48	60	6	1	.14	79	58	68	2	5	.16
20	63	40	52	14	1	.16	72	49	60	6	1	.14	80	58	69	1	5	.16
21	63	41	52	13	0	.16	72	49	61	5	1	.15	80	58	69	1	5	.16
22	63	41	52	13	0	.16	73	49	61	5	1	.15	81	58	70	1	6	.16
23	64	41	53	12	0	.16	73	50	61	5	1	.15	81	59	70	1	6	.16
24	64	42	53	12	0	.16	73	50	61	5	1	.15	81	59	70	1	6	.16
25	64	42	53	12	0	.15	73	50	62	4	1	.15	81	59	70	1	6	.15
26	65	42	53	12	0	.15	74	50	62	4	1	.15	82	60	71	1	7	.15
27	65	42	54	11	0	.15	74	51	63	4	2	.15	82	60	71	1	7	.15
28	65	43	54	11	0	.15	74	51	63	4	2	.15	82	60	71	1	7	.15
29	66	43	54	11	0	.15	74	51	63	4	2	.15	82	60	71	1	7	.15
30	66	43	55	10	0	.15	75	52	63	4	2	.16	83	61	72	1	8	.14
31	66	43	55	10	0	.15							83	61	72	1	8	.14
MONTHLY	61.2	39.1	50.2	469	10	4.85	70.8	47.5	59.2	193	19	4.37	78.8	56.6	67.7	59	143	4.88
SPRING	70.3	47.8	59.1	721	172	14.10												
ANNUAL	69.8	48.4	59.1	3729	1616	47.30												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

406402 NASHVILLE WSO AP LATITUDE: 36 07N LONGITUDE: 086 41W ELEVATION: 580 FT.

	JUNE						JULY						AUGUST					
DAILY	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	83	62	73	0	8	.14	89	68	78	0	13	.12	90	69	80	0	15	.12
2	84	62	73	0	8	.13	89	68	78	0	13	.12	90	69	79	0	14	.12
3	84	62	73	0	8	.13	89	68	78	0	13	.12	90	69	79	0	14	.12
4	84	62	73	0	8	.13	89	68	78	0	13	.13	90	69	79	0	14	.12
5	84	62	73	0	8	.13	89	68	79	0	14	.13	90	69	79	0	14	.11
6	85	63	74	0	9	.13	89	68	79	0	14	.13	89	69	79	0	14	.11
7	85	63	74	0	9	.12	89	69	79	0	14	.13	89	69	79	0	14	.11
8	85	63	74	0	9	.12	89	69	79	0	14	.13	89	69	79	0	14	.11
9	85	63	74	0	9	.12	89	69	79	0	14	.13	89	69	79	0	14	.11
10	86	64	75	0	10	.12	89	69	79	0	14	.13	89	68	79	0	14	.11
11	86	64	75	0	10	.12	89	69	79	0	14	.13	89	68	79	0	14	.11
12	86	64	75	0	10	.12	89	69	79	0	14	.13	89	68	79	0	14	.11
13	86	64	75	0	10	.12	89	69	79	0	14	.13	89	68	79	0	14	.11
14	86	65	75	0	10	.12	89	69	79	0	14	.13	89	68	79	0	14	.11
15	87	65	76	0	11	.11	89	69	79	0	14	.13	89	68	78	0	13	.11
16	87	65	76	0	11	.11	89	69	79	0	14	.13	89	68	78	0	13	.11
17	87	65	76	0	11	.11	90	69	79	0	14	.13	88	68	78	0	13	.11
18	87	65	76	0	11	.11	90	69	79	0	14	.13	88	68	78	0	13	.11
19	87	66	76	0	11	.11	90	69	80	0	15	.13	88	68	78	0	13	.11
20	88	66	77	0	12	.11	90	69	80	0	15	.13	88	67	78	0	13	.11
21	88	66	77	0	12	.11	90	69	80	0	15	.13	88	67	78	0	13	.11
22	88	66	77	0	12	.11	90	69	80	0	15	.13	88	67	78	0	13	.11
23	88	66	77	0	12	.11	90	70	80	0	15	.13	88	67	77	0	12	.11
24	88	67	77	0	12	.11	90	70	80	0	15	.13	88	67	77	0	12	.11
25	88	67	77	0	12	.12	90	70	80	0	15	.13	87	67	77	0	12	.11
26	88	67	78	0	13	.12	90	69	80	0	15	.13	87	66	77	0	12	.11
27	88	67	78	0	13	.12	90	69	80	0	15	.13	87	66	77	0	12	.11
28	89	67	78	0	13	.12	90	69	80	0	15	.13	87	66	77	0	12	.11
29	89	67	78	0	13	.12	90	69	80	0	15	.12	87	66	76	0	11	.11
30	89	67	78	0	13	.12	90	69	80	0	15	.12	86	66	76	0	11	.11
31							90	69	80	0	15	.12	86	66	76	0	11	.12
MONTHLY	86.5	64.7	75.6	0	318	3.57	89.5	68.9	79.3	0	443	3.97	88.4	67.7	78.1	0	406	3.46
SUMMER	88.2	67.2	77.7	0	1167	11.00												
ANNUAL	69.8	48.4	59.1	3729	1616	47.30												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

406402 NASHVILLE WSO AP LATITUDE: 36 07N LONGITUDE: 086 41W ELEVATION: 580 FT.

DAILY	SEPTEMBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	OCTOBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	NOVEMBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	86	65	76	0	11	.12	78	55	66	3	4	.09	66	43	55	10	0	.11
2	86	65	76	0	11	.12	78	54	66	3	4	.09	66	43	54	11	0	.11
3	86	65	75	0	10	.12	77	54	65	3	3	.09	65	43	54	11	0	.11
4	85	65	75	0	10	.12	77	53	65	3	3	.09	65	43	54	11	0	.11
5	85	65	75	0	10	.12	77	53	65	3	3	.08	65	42	53	12	0	.12
6	85	64	75	0	10	.12	76	52	64	4	3	.08	64	42	53	12	0	.12
7	85	64	74	0	9	.12	76	52	64	4	3	.08	64	42	53	12	0	.12
8	85	64	74	0	9	.12	76	51	63	5	3	.08	63	42	52	13	0	.13
9	84	64	74	0	9	.12	75	51	63	5	3	.08	63	41	52	13	0	.13
10	84	63	74	0	9	.12	75	50	62	5	2	.08	62	41	52	13	0	.13
11	84	63	73	0	8	.12	74	50	62	5	2	.08	62	41	52	13	0	.13
12	84	63	73	0	8	.12	74	49	62	5	2	.08	62	41	51	14	0	.13
13	83	62	73	0	8	.12	74	49	62	5	2	.08	61	40	51	14	0	.14
14	83	62	73	0	8	.12	73	49	61	6	2	.08	61	40	51	14	0	.14
15	83	62	72	0	7	.12	73	48	61	6	2	.08	61	40	50	15	0	.14
16	83	61	72	0	7	.12	73	48	60	6	1	.08	60	40	50	15	0	.14
17	82	61	72	0	7	.12	72	47	60	6	1	.08	60	39	50	15	0	.14
18	82	61	71	1	7	.12	72	47	60	6	1	.08	59	39	49	16	0	.14
19	82	60	71	1	7	.12	71	47	59	7	1	.08	59	39	49	16	0	.15
20	81	60	71	1	7	.12	71	46	59	7	1	.08	59	39	49	16	0	.15
21	81	59	70	1	6	.11	71	46	58	8	1	.08	58	38	48	17	0	.15
22	81	59	70	1	6	.11	70	46	58	8	1	.08	58	38	48	17	0	.15
23	80	59	70	1	6	.11	70	46	58	8	1	.08	57	38	48	17	0	.15
24	80	58	69	1	5	.11	69	45	57	9	1	.08	57	37	47	18	0	.15
25	80	57	68	2	5	.11	69	45	57	9	1	.09	57	37	47	18	0	.15
26	80	57	68	2	5	.11	69	45	57	9	1	.09	56	37	46	19	0	.15
27	79	57	68	2	5	.10	68	44	56	9	0	.09	56	36	46	19	0	.15
28	79	56	68	2	5	.10	68	44	56	9	0	.09	56	36	46	19	0	.16
29	79	56	67	3	5	.10	67	44	56	9	0	.10	55	36	45	20	0	.16
30	78	55	67	3	5	.10	67	44	55	10	0	.10	55	35	45	20	0	.16
31							67	43	55	10	0	.10						
MONTHLY	82.5	61.1	71.8	21	225	3.46	72.5	48.3	60.4	195	52	2.62	60.4	39.6	50.0	450	0	4.12
AUTUMN	71.9	49.7	60.8	666	277	10.20												
ANNUAL	69.8	48.4	59.1	3729	1616	47.30												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

LATITUDE: 38 02N LONGITUDE: 084 36W ELEVATION: 966 FT.

154746 LEXINGTON WSO AP

DAILY	DECEMBER TEMPERATURE MAX	DECEMBER TEMPERATURE MIN	DECEMBER TEMPERATURE AVG	DECEMBER DEG HDD	DECEMBER DAY CDD	DECEMBER PCP	JANUARY TEMPERATURE MAX	JANUARY TEMPERATURE MIN	JANUARY TEMPERATURE AVG	JANUARY DEG HDD	JANUARY DAY CDD	JANUARY PCP	FEBRUARY TEMPERATURE MAX	FEBRUARY TEMPERATURE MIN	FEBRUARY TEMPERATURE AVG	FEBRUARY DEG HDD	FEBRUARY DAY CDD	FEBRUARY PCP
1	49	32	41	24	0	.13	40	24	32	33	0	.11	40	22	31	34	0	.10
2	49	32	40	25	0	.13	40	24	32	33	0	.10	40	23	31	34	0	.10
3	48	31	40	25	0	.13	40	23	32	33	0	.10	40	23	32	33	0	.10
4	48	31	39	26	0	.13	40	23	31	34	0	.10	41	23	32	33	0	.10
5	47	31	39	26	0	.13	39	23	31	34	0	.10	41	23	32	33	0	.10
6	47	30	39	26	0	.13	39	23	31	34	0	.10	41	23	32	33	0	.10
7	47	30	38	27	0	.14	39	23	31	34	0	.09	41	23	32	33	0	.10
8	46	30	38	27	0	.14	39	23	31	34	0	.09	41	23	32	33	0	.11
9	46	29	38	27	0	.14	39	23	31	34	0	.09	42	24	33	32	0	.11
10	46	29	37	28	0	.14	39	23	31	34	0	.09	42	24	33	32	0	.11
11	45	29	37	28	0	.14	39	22	31	34	0	.09	42	24	33	32	0	.11
12	45	29	37	28	0	.13	39	22	31	34	0	.09	42	24	33	32	0	.11
13	45	28	37	28	0	.13	39	22	31	34	0	.09	43	25	34	31	0	.11
14	45	28	36	29	0	.13	39	22	31	34	0	.09	43	25	34	31	0	.11
15	44	28	36	29	0	.13	39	22	30	35	0	.09	43	25	34	31	0	.12
16	44	27	36	29	0	.13	39	22	30	35	0	.09	44	25	35	30	0	.12
17	44	27	35	30	0	.13	38	22	30	35	0	.09	44	26	35	30	0	.12
18	43	27	35	30	0	.13	38	22	30	35	0	.09	44	26	35	30	0	.12
19	43	27	35	30	0	.13	39	22	30	35	0	.09	45	26	36	29	0	.12
20	43	26	35	30	0	.13	39	22	30	35	0	.09	45	26	36	29	0	.12
21	43	26	34	31	0	.13	39	22	30	35	0	.09	46	27	36	29	0	.12
22	42	26	34	31	0	.13	39	22	30	35	0	.09	46	27	37	28	0	.12
23	42	26	34	31	0	.13	39	22	30	35	0	.09	46	28	37	28	0	.13
24	42	25	34	31	0	.12	39	22	31	34	0	.09	47	28	37	28	0	.13
25	[illegible]	[illegible]	33	32	0	.12	39	22	31	34	0	.09	47	28	38	27	0	.13
26	41	25	33	32	0	.12	39	22	31	34	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	41	25	33	32	0	.12	39	22	31	34	0	.09	48	29	39	26	0	.13
28	41	25	33	32	0	.12	39	22	31	34	0	.09	49	29	39	26	0	.13
29	41	24	33	32	0	.12	39	22	31	34	0	.09						
30	41	24	32	33	0	.11	39	22	31	34	0	.09						
31	40	24	32	33	0	.11	40	22	31	34	0	.09						
MONTHLY	44.2	27.6	35.9	902	0	3.98	39.1	22.4	30.8	1060	0	2.86	43.6	25.3	34.5	854	0	3.21
WINTER	42.3	25.1	33.8	2816	0	10.05												
ANNUAL	64.7	45.1	54.9	4783	1140	44.55												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F: TEMPERATURE UNITS = DEG F:
PRECIPITATION UNITS = INCHES: * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

154746 LEXINGTON WSO AP — LATITUDE: 38 02N — LONGITUDE: 084 36W — ELEVATION: 966 FT.

DAILY	MARCH TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	APRIL TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	MAY TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	49	30	39	26	0	.14	61	40	51	14	0	.13	70	49	59	7	1	.14
2	49	30	40	25	0	.14	61	40	51	14	0	.13	70	49	60	7	2	.14
3	50	31	40	25	0	.14	62	41	51	14	0	.13	70	50	60	7	2	.14
4	50	31	41	24	0	.14	62	41	51	14	0	.13	71	50	60	7	2	.14
5	51	32	41	24	0	.14	62	41	52	13	0	.13	71	50	61	6	2	.14
6	51	32	42	23	0	.14	63	41	52	13	0	.13	71	50	61	6	2	.15
7	52	32	42	23	0	.14	63	42	52	13	0	.13	72	51	61	6	2	.15
8	52	33	42	23	0	.14	63	42	53	12	0	.13	72	51	62	5	2	.15
9	53	33	43	22	0	.14	64	42	53	12	0	.13	72	51	62	5	2	.15
10	53	33	43	22	0	.14	64	43	53	12	0	.13	73	52	63	5	3	.15
11	53	34	44	21	0	.14	64	43	53	12	0	.13	73	52	63	5	3	.15
12	54	34	44	21	0	.14	65	43	54	11	0	.13	73	52	63	5	3	.15
13	54	34	44	21	0	.14	65	43	54	11	0	.12	73	53	63	5	3	.15
14	55	35	45	20	0	.15	65	44	54	11	0	.12	74	53	63	5	3	.15
15	55	35	45	20	0	.15	65	44	55	10	0	.12	74	53	63	5	3	.15
16	56	36	46	19	0	.15	66	44	55	10	0	.12	74	54	64	4	3	.15
17	56	36	46	19	0	.15	66	45	55	10	0	.13	75	54	64	4	3	.15
18	56	36	46	19	0	.15	66	45	55	10	0	.13	75	54	65	4	4	.15
19	57	36	47	18	0	.15	67	45	56	9	0	.13	75	54	65	4	4	.15
20	57	37	47	18	0	.14	67	45	56	9	0	.13	75	55	65	4	4	.15
21	57	37	47	18	0	.14	67	46	56	9	0	.13	76	55	66	3	4	.15
22	58	37	48	17	0	.14	67	46	57	8	0	.13	76	55	66	3	4	.14
23	58	38	48	17	0	.14	68	46	57	8	0	.13	76	56	66	3	4	.14
24	58	38	48	17	0	.14	68	47	57	8	0	.13	77	56	66	3	4	.14
25	59	38	49	16	0	.14	68	47	58	8	1	.13	77	56	67	3	5	.14
26	59	39	49	16	0	.14	69	47	58	8	1	.13	77	56	67	3	5	.14
27	60	39	49	16	0	.14	69	48	58	8	1	.13	78	57	67	3	5	.14
28	60	39	49	16	0	.14	69	48	59	7	1	.13	78	57	68	2	5	.14
29	60	39	50	15	0	.14	69	48	59	7	1	.14	78	57	68	2	5	.13
30	61	40	50	15	0	.14	70	49	59	7	1	.14	79	58	68	2	5	.13
31	61	40	50	[illegible]	0	[illegible]							79	58	68	2	5	.13
MONTHLY	55.3	35.3	45.3	611	0	4.40	65.5	44.2	54.8	312	6	3.88	74.3	53.5	64.0	135	104	4.47
SPRING	65.1	44.4	54.7	1058	110	12.75												
ANNUAL	64.7	45.1	54.9	4783	1140	44.55												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN ! BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

154746 LEXINGTON WSO AP LATITUDE: 38 02N LONGITUDE: 084 36W ELEVATION: 966 FT.

	JUNE						JULY						AUGUST					
	TEMPERATURE			DEG	DAY		TEMPERATURE			DEG	DAY		TEMPERATURE			DEG	DAY	
DAILY	MAX	MIN	AVG	HDD	CDD	PCP	MAX	MIN	AVG	HDD	CDD	PCP	MAX	MIN	AVG	HDD	CDD	PCP
1	79	58	69	1	5	.13	85	65	75	0	10	.14	86	66	76	0	11	.15
2	80	58	69	1	5	.13	85	65	75	0	10	.15	86	66	76	0	11	.15
3	80	59	69	1	5	.12	85	65	75	0	10	.15	86	66	76	0	11	.15
4	80	59	70	1	6	.12	85	65	75	0	10	.15	86	66	76	0	11	.14
5	80	59	70	1	6	.12	85	65	75	0	10	.15	86	66	76	0	11	.14
6	81	60	71	0	6	.12	85	65	75	0	10	.16	86	66	76	0	11	.14
7	81	60	71	0	6	.12	86	65	76	0	11	.16	86	65	76	0	11	.14
8	81	60	71	0	6	.12	86	65	76	0	11	.16	86	65	76	0	11	.14
9	82	60	71	0	6	.12	86	65	76	0	11	.16	86	65	76	0	11	.13
10	82	60	71	0	6	.12	86	66	76	0	11	.16	86	65	76	0	11	.13
11	82	61	71	0	6	.11	86	66	76	0	11	.16	86	65	75	0	10	.13
12	82	61	72	0	7	.11	86	66	76	0	11	.17	86	65	75	0	10	.13
13	82	61	72	0	7	.11	86	66	76	0	11	.17	85	65	75	0	10	.13
14	83	61	72	0	7	.11	86	66	76	0	11	.17	85	65	75	0	10	.13
15	83	62	72	0	7	.11	86	66	76	0	11	.17	85	65	75	0	10	.12
16	83	62	73	0	8	.12	86	66	76	0	11	.17	85	65	75	0	10	.12
17	83	62	73	0	8	.12	86	66	76	0	11	.17	85	64	75	0	10	.12
18	83	62	73	0	8	.12	86	66	76	0	11	.17	85	64	75	0	10	.12
19	84	62	73	0	8	.12	86	66	76	0	11	.17	85	64	75	0	10	.12
20	84	63	73	0	8	.12	86	66	76	0	11	.17	85	64	74	0	9	.12
21	84	63	73	0	8	.12	86	66	76	0	11	.17	85	64	74	0	9	.12
22	84	63	73	0	8	.12	86	66	76	0	11	.17	84	64	74	0	9	.12
23	84	63	74	0	9	.12	86	66	76	0	11	.17	84	64	74	0	9	.12
24	84	63	74	0	9	.13	86	66	76	0	11	.16	84	63	74	0	9	.12
25	85	64	74	0	9	.13	86	66	76	0	11	.16	84	63	74	0	9	.12
26	85	64	74	0	9	.13	86	66	76	0	11	.16	84	63	73	0	8	.12
27	85	64	74	0	9	.13	86	66	76	0	11	.16	83	63	73	0	8	.12
28	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	83	63	73	0	8	.11
29	85	64	75	0	10	.14	86	66	76	0	11	.16	83	63	73	0	8	.11
30	85	64	75	0	10	.14	86	66	76	0	11	.15	83	62	73	0	8	.11
31							86	66	76	0	11	.15	83	62	72	0	7	.11
MONTHLY	82.7	61.5	72.2	5	221	3.66	85.8	65.7	75.8	0	335	5.00	84.9	64.4	74.7	0	301	3.93
SUMMER	84.5	63.9	74.3	5	857	12.59												
ANNUAL	64.7	45.1	54.9	4783	1140	44.55												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
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DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

154746 LEXINGTON WSO AP   LATITUDE: 38 02N   LONGITUDE: 084 36W   ELEVATION: 966 FT.

DAILY	SEPTEMBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	82	62	72	0	7	.12
2	82	62	72	0	7	.12
3	82	62	72	0	7	.11
4	82	62	72	0	7	.11
5	81	61	71	0	6	.11
6	81	61	71	0	6	.11
7	81	61	71	0	6	.11
8	81	61	71	0	6	.11
9	80	60	70	1	6	.11
10	80	60	70	1	6	.11
11	80	60	70	1	6	.11
12	80	59	69	1	5	.11
13	79	59	69	1	5	.11
14	79	59	69	1	5	.11
15	79	59	69	1	5	.11
16	78	58	68	1	4	.11
17	78	58	68	1	4	.11
18	78	58	68	1	4	.11
19	77	57	67	2	4	.11
20	77	57	67	2	4	.11
21	77	56	67	2	4	.10
22	76	56	66	3	4	.10
23	76	56	66	3	4	.10
24	76	55	66	3	4	.10
25	75	55	65	3	3	.10
26	75	54	65	3	3	.10
27	75	54	64	4	3	.10
28	74	53	64	4	3	.10
29	74	53	64	4	3	.09
30	74	52	63	4	2	[illegible]
31						
MONTHLY	78.3	58.0	68.2	47	143	3.20
AUTUMN	66.9	47.0	57.0	904	173	9.16
ANNUAL	64.7	45.1	54.9	4783	1140	44.55

DAILY	OCTOBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	73	52	63	4	2	.09
2	73	52	62	5	2	.09
3	72	51	62	5	2	.09
4	72	51	61	6	2	.09
5	72	50	61	6	2	.08
6	71	50	61	6	2	.08
7	71	49	60	7	2	.08
8	70	49	60	7	2	.08
9	70	48	59	7	1	.08
10	70	48	59	7	1	.08
11	69	48	58	8	1	.08
12	69	47	58	8	1	.08
13	68	47	58	8	1	.08
14	68	46	57	9	1	.08
15	68	46	57	9	1	.08
16	67	46	57	9	1	.08
17	67	45	56	10	1	.08
18	66	45	56	10	1	.08
19	66	45	55	11	1	.08
20	66	44	55	11	1	.08
21	65	44	55	11	1	.08
22	65	44	55	11	1	.08
23	64	43	54	11	0	.08
24	64	43	54	11	0	.08
25	64	43	53	12	0	.08
26	63	42	53	12	0	.08
27	63	42	53	12	0	.09
28	62	42	52	13	0	.09
29	62	42	52	13	0	.09
30	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
31	61	41	51	14	0	.09
MONTHLY	67.2	46.0	56.7	287	30	2.57

DAILY	NOVEMBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	61	41	51	14	0	.09
2	60	41	51	14	0	.09
3	60	41	50	15	0	.10
4	60	40	50	15	0	.10
5	59	40	50	15	0	.10
6	59	40	49	16	0	.10
7	58	40	49	16	0	.10
8	58	39	49	16	0	.10
9	57	39	48	17	0	.10
10	57	39	48	17	0	.11
11	57	38	48	17	0	.11
12	56	38	47	18	0	.11
13	56	38	47	18	0	.11
14	55	38	47	18	0	.11
15	55	37	46	19	0	.11
16	55	37	46	19	0	.11
17	54	37	45	20	0	.12
18	54	36	45	20	0	.12
19	53	36	45	20	0	.12
20	53	36	44	21	0	.12
21	53	35	44	21	0	.12
22	52	35	44	21	0	.12
23	52	35	43	22	0	.12
24	52	35	43	22	0	.12
25	51	34	43	22	0	.13
26	51	34	42	23	0	.13
27	50	33	42	23	0	.13
28	50	33	42	23	0	.13
29	50	33	41	24	0	.13
30	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
31						
MONTHLY	54.9	37.0	46.0	570	0	3.39

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F: TEMPERATURE UNITS = DEG F:
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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

154954 LOUISVILLE WSFO AP LATITUDE: 38 11N LONGITUDE: 085 44W ELEVATION: 477 FT.

DAILY	DECEMBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	JANUARY TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	FEBRUARY TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	50	33	42	23	0	.13	41	24	33	32	0	.10	41	24	32	33	0	.10
2	50	33	41	24	0	.13	41	24	33	32	0	.10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	49	32	41	24	0	.13	41	24	33	32	0	.10	42	24	33	32	0	.10
4	49	32	41	24	0	.13	41	24	32	33	0	.10	42	24	33	32	0	.10
5	49	32	40	25	0	.13	40	24	32	33	0	.09	42	24	33	32	0	.10
6	48	31	40	25	0	.13	40	24	32	33	0	.09	42	24	33	32	0	.11
7	48	31	39	26	0	.13	40	23	32	33	0	.09	43	24	34	31	0	.11
8	47	31	39	26	0	.13	40	23	32	33	0	.09	43	25	34	31	0	.11
9	47	30	39	26	0	.12	40	23	32	33	0	.09	43	25	34	31	0	.11
10	47	30	38	27	0	.12	40	23	32	33	0	.09	43	25	34	31	0	.11
11	46	30	38	27	0	.12	40	23	32	33	0	.09	43	25	34	31	0	.11
12	46	30	38	27	0	.12	40	23	31	34	0	.09	44	26	35	30	0	.11
13	46	29	38	27	0	.12	40	23	31	34	0	.09	44	26	35	30	0	.11
14	45	29	37	28	0	.12	40	23	31	34	0	.09	44	26	35	30	0	.12
15	45	29	37	28	0	.12	40	23	31	34	0	.09	45	26	36	29	0	.12
16	45	28	37	28	0	.12	40	23	31	34	0	.09	45	27	36	29	0	.12
17	45	28	36	29	0	.12	40	23	31	34	0	.09	45	27	36	29	0	.12
18	44	28	36	29	0	.12	40	23	31	34	0	.09	46	27	36	29	0	.12
19	44	28	36	29	0	.12	40	23	31	34	0	.09	46	27	37	28	0	.12
20	44	27	36	29	0	.11	40	23	31	34	0	.09	46	28	37	28	0	.13
21	43	27	35	30	0	.11	40	23	31	34	0	.09	47	28	37	28	0	.13
22	43	27	35	30	0	.11	40	23	31	34	0	.09	47	28	38	27	0	.13
23	43	27	35	30	0	.11	40	23	31	34	0	.09	47	29	38	27	0	.13
24	43	26	35	30	0	.11	40	23	32	33	0	.09	48	29	39	26	0	.13
25	42	26	34	31	0	.11	40	23	32	33	0	.09	48	29	39	26	0	.13
26	42	26	34	31	0	.11	40	23	32	33	0	.09	49	30	39	26	0	.14
27	42	26	34	31	0	.11	41	23	32	33	0	.09	49	30	40	25	0	.14
28	42	26	34	31	0	.10	41	23	32	33	0	.09	50	31	40	25	0	.14
29	42	25	33	32	0	.10	41	23	32	33	0	.10						
30	41	25	33	32	0	.10	41	23	32	33	0	.10						
31	41	25	33	32	0	.10	41	23	32	33	0	.10						
MONTHLY	45.1	28.6	36.9	871	0	3.64	40.3	23.2	31.7	1032	0	2.86	44.8	26.5	35.7	820	0	3.30
WINTER	43.4	26.1	34.8	2723	0	9.80												
ANNUAL	66.0	46.0	56.1	4514	1288	44.39												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F: TEMPERATURE UNITS = DEG F:

PRECIPITATION UNITS = INCHES: * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF T[illegible] UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

154954 LOUISVILLE WSFO AP LATITUDE: 38 11N LONGITUDE: 085 44W ELEVATION: 477 FT.

DAILY	MARCH TEMPERATURE MAX	MIN	AVG	DEG DAY HDD	CDD	PCP	APRIL TEMPERATURE MAX	MIN	AVG	DEG DAY HDD	CDD	PCP	MAY TEMPERATURE MAX	MIN	AVG	DEG DAY HDD	CDD	PCP
1	50	31	41	24	0	.14	62	41	52	13	0	.15	72	50	61	6	2	.15
2	50	31	41	24	0	.14	63	41	52	13	0	.14	72	50	61	6	2	.15
3	51	32	41	24	0	.14	63	42	53	12	0	.14	72	51	62	5	2	.15
4	51	32	42	23	0	.15	64	42	53	12	0	.14	73	51	62	5	2	.15
5	52	32	42	23	0	.15	64	42	53	12	0	.14	73	51	62	5	2	.15
6	52	33	43	22	0	.15	64	43	53	12	0	.14	73	52	62	5	2	.15
7	53	33	43	22	0	.15	65	43	54	11	0	.14	74	52	63	5	3	.15
8	53	34	43	22	0	.15	65	43	54	11	0	.14	74	52	63	5	3	.16
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	74	53	63	5	3	.16
10	54	34	44	21	0	.15	66	44	55	10	0	.14	[illegible]	[illegible]	[illegible]	4	3	.16
11	54	35	45	20	0	.15	66	44	55	10	0	.14	75	53	64	4	3	.16
12	55	35	45	20	0	.15	66	44	55	10	0	.14	75	54	64	4	3	.16
13	55	35	45	20	0	.15	67	45	56	9	0	.14	75	54	64	4	3	.16
14	56	36	46	19	0	.15	67	45	56	9	0	.14	75	54	65	3	3	.16
15	56	36	46	19	0	.15	67	45	56	9	0	.14	76	54	65	3	3	.15
16	56	36	46	19	0	.15	67	46	56	9	0	.14	76	55	65	3	3	.15
17	57	37	47	18	0	.16	68	46	57	8	0	.14	76	55	66	3	4	.15
18	57	37	47	18	0	.16	68	46	57	8	0	.14	77	55	66	3	4	.15
19	58	37	47	18	0	.16	68	46	57	8	0	.14	77	56	66	3	4	.15
20	58	38	48	17	0	.16	69	47	58	8	1	.14	77	56	66	3	4	.15
21	58	38	48	17	0	.15	69	47	58	8	1	.14	77	56	67	2	4	.15
22	59	38	49	16	0	.15	69	47	58	8	1	.14	78	57	67	2	4	.15
23	59	39	49	16	0	.15	70	48	59	7	1	.14	78	57	68	2	5	.15
24	60	39	49	16	0	.15	70	48	59	7	1	.14	78	57	68	2	5	.15
25	60	39	50	15	0	.15	70	48	59	7	1	.14	78	57	68	2	5	.14
26	60	39	50	15	0	.15	71	48	59	7	1	.14	79	58	68	2	5	.14
27	61	40	50	15	0	.15	71	49	60	6	1	.14	79	58	68	2	5	.14
28	61	40	51	14	0	.15	71	49	60	6	1	.14	79	58	69	2	6	.14
29	61	40	51	14	0	.15	71	49	60	6	1	.15	80	59	69	2	6	.13
30	62	41	51	14	0	.15	72	50	61	6	2	.15	80	59	69	2	6	.13
31	62	41	51	14	0	.15							80	59	70	1	6	.13
MONTHLY	56.3	36.2	46.3	580	0	4.66	67.3	45.4	56.3	273	12	4.23	76.0	54.7	65.3	105	115	4.62
SPRING	66.6	45.5	56.0	958	127	13.51												
ANNUAL	66.0	46.0	56.1	4514	1288	44.39												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

LATITUDE: 38 11N LONGITUDE: 085 44W ELEVATION: 477 FT.

154954 LOUISVILLE WSFO AP

DAILY	JUNE TEMPERATURE MAX	JUNE TEMPERATURE MIN	JUNE TEMPERATURE AVG	JUNE DEG DAY HDD	JUNE DEG DAY CDD	JUNE PCP	JULY TEMPERATURE MAX	JULY TEMPERATURE MIN	JULY TEMPERATURE AVG	JULY DEG DAY HDD	JULY DEG DAY CDD	JULY PCP	AUGUST TEMPERATURE MAX	AUGUST TEMPERATURE MIN	AUGUST TEMPERATURE AVG	AUGUST DEG DAY HDD	AUGUST DEG DAY CDD	AUGUST PCP
1	80	59	70	1	6	.13	86	66	76	0	11	.13	87	67	77	0	12	.13
2	81	60	70	1	6	.12	86	66	76	0	11	.13	87	67	77	0	12	.13
3	81	60	[illegible]	1	[illegible]	[illegible]	87	66	76	0	11	.14	87	67	77	0	12	.13
4	81	60	71	1	7	.12	87	66	[illegible]	[illegible]	[illegible]	[illegible]	87	67	77	0	12	.13
5	81	60	71	1	7	.12	87	67	77	0	12	.14	87	67	[illegible]	[illegible]	[illegible]	[illegible]
6	82	61	71	1	7	.12	87	67	77	0	12	.14	87	67	77	0	12	.12
7	82	61	72	0	7	.11	87	67	77	0	12	.14	87	67	77	0	12	.12
8	82	61	72	0	7	.11	87	67	77	0	12	.15	87	67	77	0	12	.12
9	82	62	72	0	7	.11	87	67	77	0	12	.15	86	67	77	0	12	.12
10	83	62	72	0	7	.11	87	67	77	0	12	.15	86	67	77	0	12	.12
11	83	62	72	0	7	.11	87	67	77	0	12	.15	86	67	77	0	12	.11
12	83	62	73	0	8	.11	87	67	77	0	12	.15	86	67	76	0	11	.11
13	83	62	73	0	8	.11	87	67	77	0	12	.15	86	66	76	0	11	.11
14	83	63	73	0	8	.11	87	67	77	0	12	.15	86	66	76	0	11	.11
15	84	63	73	0	8	.11	87	67	77	0	12	.15	86	66	76	0	11	.11
16	84	63	73	0	8	.11	87	67	77	0	12	.15	86	66	76	0	11	.11
17	84	63	74	0	9	.11	87	68	77	0	12	.15	86	66	76	0	11	.11
18	84	64	74	0	9	.11	87	68	78	0	13	.15	86	66	76	0	11	.11
19	84	64	74	0	9	.11	87	68	78	0	13	.15	86	66	76	0	11	.11
20	84	64	74	0	9	.11	87	68	78	0	13	.15	85	65	75	0	10	.11
21	85	64	74	0	9	.11	88	68	78	0	13	.15	85	65	75	0	10	.11
22	85	64	75	0	10	.11	88	68	78	0	13	.15	85	65	75	0	10	.11
23	85	65	75	0	10	.11	87	68	78	0	13	.15	85	65	75	0	10	.11
24	85	65	75	0	10	.12	87	68	78	0	13	.15	85	65	75	0	10	.11
25	85	65	75	0	10	.12	87	68	78	0	13	.15	85	65	75	0	10	.11
26	85	65	75	0	10	.12	87	68	78	0	13	.15	85	64	75	0	10	.10
27	86	65	75	0	10	.12	87	68	78	0	13	.14	84	64	74	0	9	.11
28	86	66	76	0	11	.12	87	68	77	0	12	.14	84	64	74	0	9	.11
29	86	66	76	0	11	.13	87	68	77	0	12	.14	84	64	74	0	9	.11
30	86	66	76	0	11	.13	87	67	77	0	12	.14	84	64	74	0	9	.11
31							87	67	77	0	12	.14	84	64	74	0	9	.11
MONTHLY	83.5	62.9	73.2	6	252	3.46	87.0	67.3	77.2	0	378	4.51	85.7	65.8	75.8	0	335	3.54
SUMMER	85.5	65.4	75.5	6	965	11.51												
ANNUAL	66.0	46.0	56.1	4514	1288	44.39												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
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CLIMATOGRAPHY OF T[illegible] UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

154954 LOUISVILLE WSFO AP LATITUDE: 38 11N LONGITUDE: 085 44W ELEVATION: 477 FT.

DAILY	SEPTEMBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	OCTOBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	NOVEMBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	84	63	74	0	9	.11	75	52	64	4	3	.09	63	41	52	13	0	.10
2	84	63	73	0	8	.11	75	52	63	4	2	.09	62	41	52	13	0	.11
3	83	63	73	0	8	.11	74	51	63	4	2	.09	62	40	51	14	0	.11
4	83	63	73	0	8	.11	74	51	62	5	2	.09	62	40	51	14	0	.11
5	83	62	73	0	8	.11	74	50	62	5	2	.09	61	40	51	14	0	.11
6	83	62	72	0	7	.11	73	50	62	5	2	.09	61	40	50	15	0	.11
7	83	62	72	0	7	.11	73	49	61	6	2	.09	60	40	50	15	0	.12
8	82	62	72	0	7	.11	72	49	61	6	2	.08	60	39	50	15	0	.12
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	82	61	72	0	7	.11	72	48	60	6	1	.08	59	39	49	16	0	.12
11	82	61	71	0	6	.11	71	47	59	7	1	.08	59	39	49	16	0	.12
12	82	60	71	0	6	.11	71	47	59	7	1	.08	58	38	48	17	0	.12
13	81	60	70	1	6	.11	70	47	59	7	1	.08	58	38	48	17	0	.12
14	81	60	70	1	6	.11	70	46	58	8	1	.08	57	38	48	17	0	.13
15	81	59	70	1	6	.11	70	46	58	8	1	.08	57	38	47	18	0	.13
16	80	59	70	1	6	.11	70	45	58	8	1	.08	57	37	47	18	0	.13
17	80	58	69	1	5	.11	69	45	57	8	0	.08	56	37	47	18	0	.13
18	80	58	69	1	5	.11	68	45	57	8	0	.08	56	37	46	19	0	.13
19	80	58	69	1	5	.10	68	44	56	9	0	.08	55	36	46	19	0	.13
20	79	57	68	2	5	.10	68	44	56	9	0	.09	55	36	46	19	0	.13
21	79	57	68	2	5	.10	67	44	55	10	0	.09	54	36	45	20	0	.13
22	79	56	68	2	5	.10	67	43	55	10	0	.09	54	36	45	20	0	.13
23	78	56	67	2	4	.10	66	43	55	10	0	.09	54	35	45	20	0	.13
24	78	56	67	2	4	.10	66	43	54	11	0	.09	53	35	44	21	0	.13
25	78	55	66	3	4	.10	66	42	54	11	0	.09	53	35	44	21	0	.13
26	77	55	66	3	4	.10	65	42	54	11	0	.09	52	34	43	22	0	.13
27	77	54	66	3	4	.10	65	42	53	12	0	.09	52	34	43	22	0	.13
28	76	54	65	3	3	.10	64	42	53	12	0	.10	52	34	43	22	0	.13
29	76	53	65	3	3	.09	64	41	53	12	0	.10	51	34	42	23	0	.13
30	76	53	64	4	3	.09	64	41	53	12	0	.10	51	33	42	23	0	.13
31							63	41	52	13	0	.10						
MONTHLY	80.3	58.7	69.5	36	171	3.16	69.2	45.8	57.6	254	25	2.71	56.8	37.3	47.1	537	0	3.70
AUTUMN	68.8	47.3	58.1	827	196	9.57												
ANNUAL	66.0	46.0	56.1	4514	1288	44.39												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

156110 PADUCAH WSO LATITUDE: 37 04N LONGITUDE: 088 46W ELEVATION: 410 FT.

DAILY	DECEMBER TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	JANUARY TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	FEBRUARY TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	51	33	42	23	0	.16	42	25	33	32	0	.12	43	24	34	31	0	.12
2	51	33	42	23	0	.16	42	24	33	32	0	.12	43	24	34	31	0	.12
3	50	32	41	24	0	.16	42	24	33	32	0	.12	43	25	34	31	0	.12
4	50	32	41	24	0	.16	42	24	33	32	0	.11	43	25	34	31	0	.12
5	49	32	41	24	0	.16	42	24	33	32	0	.11	43	25	34	31	0	.13
6	49	31	40	25	0	.16	42	24	33	32	0	.11	44	25	34	31	0	.13
7	49	31	40	25	0	.16	41	24	33	32	0	.11	44	25	35	30	0	.13
8	48	31	39	26	0	.16	41	24	33	32	0	.11	44	26	35	30	0	.13
9	48	30	39	26	0	.16	41	24	33	32	0	.10	44	26	35	30	0	.13
10	48	30	39	26	0	.16	41	23	32	33	0	.10	45	26	35	30	0	.13
11	47	30	38	27	0	.16	41	23	32	33	0	.10	45	26	36	29	0	.14
12	47	29	38	27	0	.16	41	23	32	33	0	.10	45	26	36	29	0	.14
13	47	29	38	27	0	.16	41	23	32	33	0	.10	46	27	36	29	0	.14
14	46	29	38	27	0	.16	41	23	32	33	0	.10	46	27	36	29	0	.14
15	46	28	37	28	0	.16	41	23	32	33	0	.10	46	27	37	28	0	.14
16	46	28	37	28	0	.16	41	23	32	33	0	.10	46	28	37	28	0	.14
17	45	28	37	28	0	.15	41	23	32	33	0	.10	47	28	37	28	0	.15
18	45	28	36	29	0	.15	41	23	32	33	0	.10	47	28	38	27	0	.15
19	45	27	36	29	0	.15	41	23	32	33	0	.10	47	28	38	27	0	.15
20	45	27	36	29	0	.15	41	23	32	33	0	.10	48	29	38	27	0	.15
21	44	27	36	29	0	.15	41	23	32	33	0	.10	48	29	39	26	0	.15
22	44	26	35	30	0	.15	41	23	32	33	0	.10	49	29	39	26	0	.15
23	44	26	35	30	0	.14	42	23	33	32	0	.10	49	30	39	26	0	.15
24	44	26	35	30	0	.14	42	23	33	32	0	.10	49	30	40	25	0	.15
25	44	26	35	30	0	.14	42	23	33	32	0	.10	50	30	40	25	0	.15
26	43	26	35	30	0	.14	42	24	33	32	0	.11	50	31	41	24	0	.15
27	43	25	34	31	0	.14	42	24	33	32	0	.11	51	31	41	24	0	.15
28	43	25	34	31	0	.13	42	24	33	32	0	.11	51	32	41	24	0	.15
29	43	25	34	31	0	.13	42	24	33	32	0	.11						
30	43	25	34	31	0	.13	42	24	33	32	0	.11						
31	42	25	34	31	0	.13	43	24	34	31	0	.11						
MONTHLY	46.1	28.4	37.3	859	0	4.68	41.5	23.5	32.6	1004	0	3.27	46.3	27.4	36.9	787	0	3.90
WINTER	44.6	26.5	35.6	2650	0	11.85												
ANNUAL	67.4	46.9	57.2	4279	1475	49.31												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

156110 PADUCAH WSO — LATITUDE: 37 04N — LONGITUDE: 088 46W — ELEVATION: 410 FT.

DAILY	MARCH TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	APRIL TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP	MAY TEMPERATURE MAX	MIN	AVG	DEG HDD	DAY CDD	PCP
1	51	32	42	23	0	.15	64	43	53	12	0	.16	73	52	62	5	2	.17
2	52	32	42	23	0	.15	64	43	54	11	0	.16	73	52	63	4	2	.17
3	52	33	42	23	0	.15	64	43	54	11	0	.16	74	52	63	4	2	.17
4	53	33	43	22	0	.15	65	44	54	11	0	.16	74	52	63	4	2	.17
5	53	34	43	22	0	.16	65	44	55	10	0	.16	74	53	64	4	3	.17
6	53	34	44	21	0	.16	66	44	55	10	0	.16	74	53	64	4	3	.17
7	54	34	44	21	0	.16	66	45	55	10	0	.16	75	53	64	4	3	.17
8	54	35	44	21	0	.16	66	45	56	9	0	.16	75	54	64	4	3	.17
9	55	35	45	20	0	.16	67	45	56	9	0	.16	75	54	65	3	3	.16
10	55	35	45	20	*	.16	67	46	56	9	0	.17	75	54	65	3	3	.16
11	55	36	45	20	*	.16	67	46	57	8	0	.17	76	54	65	3	3	.16
12	56	36	46	20	*	.16	68	46	57	8	0	.17	76	55	65	3	3	.16
13	56	37	47	19	*	.16	68	46	57	8	0	.17	76	55	66	3	4	.16
14	57	37	47	19	*	.16	68	47	57	8	0	.17	77	55	66	3	4	.16
15	58	37	48	18	*	.16	68	47	57	8	0	.17	77	56	66	3	4	.16
16	58	38	48	18	*	.16	69	47	58	8	1	.17	77	56	67	3	5	.16
17	58	38	48	18	*	.16	69	48	59	7	1	.17	77	56	67	3	5	.16
18	58	38	48	18	*	.16	69	48	59	7	1	.17	78	57	67	3	5	.16
19	59	39	49	17	*	.16	70	48	59	7	1	.17	78	57	68	2	5	.16
20	59	39	49	16	*	.16	70	49	60	6	1	.17	78	57	68	2	5	.16
21	60	39	49	16	*	.16	70	49	60	6	1	.17	79	57	68	2	5	.16
22	60	40	50	15	0	.16	71	49	60	6	1	.17	79	58	68	2	5	.16
23	60	40	50	15	0	.16	71	49	60	6	1	.17	79	58	69	2	6	.15
24	61	40	51	14	0	.16	71	50	60	6	1	.17	80	58	69	2	6	.15
25	61	41	51	14	0	.16	72	50	61	5	1	.17	80	59	69	2	6	.15
26	61	41	51	14	0	.16	72	50	61	5	1	.17	80	59	70	1	6	.15
27	62	41	52	13	0	.16	72	50	61	5	1	.17	81	59	70	1	6	.15
28	62	42	52	13	0	.16	72	51	62	5	2	.17	81	60	70	1	6	.15
29	63	42	52	13	0	.16	73	51	62	5	2	.17	81	60	71	1	7	.15
30	63	42	53	12	0	.16	73	51	62	5	2	.17	82	60	71	1	7	.15
31	63	42	53	12	0	.16							82	61	71	1	7	.14
MONTHLY	57.5	37.5	47.5	550	8	4.92	68.6	47.1	57.9	231	18	5.01	77.3	56.0	66.7	83	136	4.94
SPRING	67.8	46.9	57.4	864	162	14.87												
ANNUAL	67.4	46.9	57.2	4279	1475	49.31												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

156110 PADUCAH WSO LATITUDE: 37 04N LONGITUDE: 088 46W ELEVATION: 410 FT.

DAILY	JUNE						JULY						AUGUST					
	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP
1	82	61	72	0	7	.14	89	68	78	0	13	.14	89	68	79	0	14	.12
2	83	61	72	0	7	.14	89	68	78	0	13	.14	89	68	79	0	14	.12
3	83	62	72	0	7	.14	89	68	78	0	13	.14	89	68	78	0	13	.11
4	83	62	72	0	7	.14	89	68	78	0	13	.14	89	68	78	0	13	.11
5	83	62	73	0	8	.14	89	68	78	0	13	.14	89	68	78	0	13	.11
6	84	62	73	0	8	.14	89	68	78	0	13	.14	89	68	78	0	13	.11
7	84	63	73	0	8	.14	89	68	79	0	14	.14	89	67	78	0	13	.11
8	84	63	74	0	9	.14	89	68	79	0	14	.14	88	67	78	0	13	.11
9	85	63	74	0	9	.14	89	68	79	0	14	.14	88	67	78	0	13	.11
10	85	63	74	0	9	.14	89	68	79	0	14	.14	88	67	78	0	13	.11
11	85	64	74	0	9	.14	89	69	79	0	14	.14	88	67	78	0	13	.11
12	85	64	75	0	10	.13	89	69	79	0	14	.14	88	67	77	0	12	.10
13	86	64	75	0	10	.13	89	69	79	0	14	.14	88	67	77	0	12	.10
14	86	64	75	0	10	.13	89	69	79	0	14	.14	88	66	77	0	12	.10
15	86	65	75	0	10	.13	89	69	79	0	14	.14	88	66	77	0	12	.10
16	86	65	76	0	11	.13	89	69	79	0	14	.14	88	66	77	0	12	.10
17	86	65	76	0	11	.13	89	69	79	0	14	.14	87	66	77	0	12	.10
18	87	65	76	0	11	.13	89	69	79	0	14	.14	87	66	77	0	12	.10
19	87	66	76	0	11	.13	89	69	79	0	14	.14	87	66	77	0	12	.10
20	87	66	76	0	11	.13	89	69	79	0	14	.14	87	66	76	0	11	.10
21	87	66	77	0	12	.13	89	69	79	0	14	.13	87	65	76	0	11	.10
22	87	66	77	0	12	.13	89	69	79	0	14	.13	87	65	76	0	11	.11
23	87	66	77	0	12	.13	89	69	79	0	14	.13	87	65	76	0	11	.11
24	88	67	77	0	12	.13	89	69	79	0	14	.13	86	65	76	0	11	.11
25	88	67	77	0	12	.13	89	69	79	0	14	.13	86	65	76	0	11	.11
26	88	67	77	0	12	.13	89	68	79	0	14	.13	86	65	75	0	10	.11
27	88	67	77	0	12	.14	89	68	79	0	14	.13	86	64	75	0	10	.11
28	88	67	78	0	13	.14	89	68	79	0	14	.12	86	64	75	0	10	.11
29	88	67	78	0	13	.14	89	68	79	0	14	.12	85	64	75	0	10	.11
30	88	68	78	0	13	.14	89	68	79	0	14	.12	85	64	75	0	10	.11
31							89	68	79	0	14	.12	85	64	74	0	9	.12
MONTHLY	85.8	64.6	75.2	0	306	4.05	89.0	68.5	78.8	0	428	4.19	87.4	66.1	76.8	0	366	3.34
SUMMER	87.5	66.5	77.0	0	1100	11.58												
ANNUAL	67.4	46.9	57.2	4279	1475	49.31												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F;
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CLIMATOGRAPHY OF THE UNITED STATES NO. 84

DAILY NORMALS OF TEMPERATURE, HEATING AND COOLING DEGREE DAYS, AND PRECIPITATION 1961-90

156110 PADUCAH WSO

LATITUDE: 37 04N LONGITUDE: 088 46W ELEVATION: 410 FT.

DAILY	SEPTEMBER						OCTOBER						NOVEMBER					
	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP	TEMPERATURE MAX	TEMPERATURE MIN	TEMPERATURE AVG	DEG HDD	DAY CDD	PCP
1	85	64	74	0	9	.12	76	53	65	3	3	.11	64	42	53	12	0	.12
2	85	63	74	0	9	.12	76	52	64	4	3	.10	63	42	53	12	0	.12
3	84	63	74	0	9	.12	76	52	64	4	3	.10	63	42	52	13	0	.12
4	84	63	74	0	9	.12	75	51	63	4	2	.10	63	41	52	13	0	.12
5	84	63	73	0	8	.12	75	51	63	4	2	.10	62	41	52	13	0	.13
6	84	62	73	0	8	.12	75	51	63	4	2	.10	62	41	51	14	0	.13
7	83	62	73	0	8	.13	74	50	62	5	2	.10	61	41	51	14	0	.13
8	83	62	73	0	8	.13	74	50	62	5	2	.09	61	40	51	14	0	.13
9	83	62	72	0	7	.13	73	49	61	6	2	.09	60	40	50	15	0	.13
10	83	61	72	0	7	.13	73	49	61	6	2	.09	60	40	50	15	0	.14
11	82	61	72	0	7	.13	73	48	60	6	1	.09	60	40	50	15	0	.14
12	82	61	72	0	7	.13	72	48	60	6	1	.09	59	39	49	16	0	.14
13	82	61	71	0	6	.13	72	48	60	6	1	.09	59	39	49	16	0	.14
14	82	60	71	0	6	.13	72	47	59	7	1	.09	58	39	49	16	0	.14
15	81	60	71	0	6	.13	71	47	59	7	1	.09	58	39	48	17	0	.15
16	81	59	70	1	6	.13	71	46	59	7	1	.09	57	38	48	17	0	.15
17	81	59	70	1	6	.13	70	46	58	8	1	.09	57	38	47	18	0	.15
18	80	59	69	1	5	.13	70	46	58	8	1	.09	56	38	47	18	0	.15
19	80	58	69	1	5	.13	70	45	58	8	1	.09	56	37	47	18	0	.15
20	80	58	69	1	5	.12	69	45	57	9	1	.09	56	37	46	19	0	.15
21	79	58	69	1	5	.12	69	44	56	9	0	.09	55	37	46	19	0	.15
22	79	57	68	1	4	.12	68	44	56	9	0	.09	55	36	46	19	0	.16
23	79	57	68	1	4	.12	68	44	56	9	0	.10	54	36	45	20	0	.16
24	79	56	68	1	4	.12	67	44	56	9	0	.10	54	36	45	20	0	.16
25	78	56	67	2	4	.12	67	44	55	10	0	.10	54	35	44	21	0	.16
26	78	55	67	2	4	.12	67	43	55	10	0	.10	53	35	44	21	0	.16
27	78	55	67	2	4	.11	66	43	55	10	0	.10	53	35	44	21	0	.16
28	77	54	66	3	4	.11	66	43	54	11	0	.11	52	34	43	22	0	.16
29	77	54	65	3	3	.11	65	43	54	11	0	.11	52	34	43	22	0	.16
30	77	53	65	3	3	.11	65	42	54	11	0	.11	51	34	42	23	0	.16
31							64	42	53	12	0	.11						
MONTHLY	81.0	59.2	70.2	24	180	3.69	70.6	46.8	58.7	228	33	3.00	57.6	38.2	47.9	513	0	4.32
AUTUMN	69.8	48.1	59.0	765	213	11.01												
ANNUAL	67.4	46.9	57.2	4279	1475	49.31												

NOTES: DEGREE DAYS BASE TEMPERATURE = 65 DEG F; TEMPERATURE UNITS = DEG F; PRECIPITATION UNITS = INCHES; * = LESS THAN 1 BUT GREATER THAN 0

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 99
Witness: Smith

Data Request:

Please provide the actual annual heating degree days observed during the period 1961-1990 for each of the five stations listed on page 10, lines 23-27.

Response:

See attached actual annual heating degree days (HDDs) observed during the period 1961-1990 for each of the five weather stations.

I would urge caution in the use of this actual data for any analysis for which the Attorney General may be contemplating. In the response to AG DR 98, Western provided the NOAA report on "Climatography of the United States No. 84", which indicates a 30 year annual HDD. This value differs slightly from the 30 year average HDDs shown on the attachment to this response (AG DR 99). The reason for this difference is that NOAA stylizes actual weather data for purposes of calculating and reporting the 30 year normal weather data shown on the NOAA report on "Climatography of the United States No. 84". As indicated in the footnote of the NOAA report on "Climatography of the United States No. 84", the daily values are interpolated from the much less variable monthly normal values by use of natural spline function. In effect, this interpolation smoothes the curve and softening the typical random patterns observed in daily data. We refer to this data as stylized. The effect is to give a better representation of what is considered by NOAA to be "normal." Western used NOAA's stylized 30 year normals for its analysis in order to establish the best benchmark for use in normalization and its WNA.

Station: (154746) LEXINGTON_WSO_AIRPORT, KY
From Year 1961 To 1990
Heating Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	1144	672	554	490	188	21	0	0	32	226	588	907	4822
1962	1081	726	718	411	21	3	0	0	94	243	621	1054	4972
1963	1183	1014	495	268	126	2	0	1	55	84	540	1217	4985
1964	924	952	606	222	55	16	0	11	61	375	502	850	4574
1965	1010	851	834	277	26	8	0	9	52	346	558	777	4748
1966	1225	883	631	373	167	21	0	3	62	340	570	908	5183
1967	851	967	468	223	138	23	1	4	83	289	722	800	4569
1968	1090	1065	581	298	124	8	0	5	20	296	552	938	4977
1969	1011	799	800	261	77	17	0	0	44	274	657	996	4936
1970	1209	908	750	251	84	1	6	0	31	229	637	821	4927
1971	1087	838	759	382	198	0	0	0	8	69	536	591	4468
1972	909	917	700	343	96	47	10	1	20	366	612	739	4760
1973	920	827	353	371	167	0	0	1	21	172	490	880	4202
1974	744	767	514	289	128	37	0	0	125	338	578	836	4356
1975	852	705	726	387	51	4	0	0	128	249	488	895	4485
1976	1130	606	468	339	158	2	1	4	64	474	829	1050	5125
1977	1457	836	444	208	52	19	0	0	6	277	498	972	4769
1978	1338	1219	755	254	179	6	0	0	20	348	492	834	5445
1979	1277	1061	522	337	110	15	0	5	40	307	574	833	5081
1980	1005	1057	721	371	88	17	0	0	23	358	633	892	5165
1981	1156	777	687	182	180	0	0	0	77	286	568	985	4898
1982	1134	844	549	429	14	9	0	1	75	259	500	646	4460
1983	961	772	580	422	151	7	0	0	59	201	550	1128	4831
1984	1152	685	778	370	178	3	2	0	89	84	689	601	4631
1985	1275	959	510	228	66	23	0	0	72	179	360	1092	4764
1986	978	735	561	259	94	2	0	15	14	250	595	903	4406
1987	1016	749	559	342	39	0	0	0	17	399	447	804	4372
1988	1085	901	620	328	90	18	0	3	30	474	560	877	4986
1989	750	887	548	351	196	8	0	6	61	267	592	1297	4963
1990	720	608	505	378	128	17	0	3	57	288	453	757	3914
Avg	1055	852	609	321	112	11	0	2	51	278	566	896	4759

'-999' = missing

Station: (154746) LEXINGTON_WSO_AIRPORT, KY
From Year 1961 To 1990
Cooling Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	0	0	0	9	19	182	336	289	248	21	5	0	1109
1962	0	0	0	37	233	247	326	333	101	58	0	0	1335
1963	0	0	0	48	64	221	273	241	109	56	0	0	1012
1964	0	0	0	25	122	301	323	327	165	1	0	0	1264
1965	0	0	0	15	154	204	276	312	175	11	0	0	1147
1966	0	0	4	11	34	223	390	245	80	10	0	0	997
1967	0	0	10	46	53	243	239	186	86	21	0	0	884
1968	0	0	1	5	38	224	344	337	110	41	1	0	1101
1969	0	0	0	7	97	260	404	309	134	57	0	0	1268
1970	0	0	0	26	137	199	295	306	266	11	0	0	1240
1971	0	0	0	0	25	266	281	285	239	65	10	0	1171
1972	0	0	0	11	47	130	287	250	171	0	4	0	900
1973	0	0	12	18	21	266	342	314	245	51	0	0	1269
1974	0	0	10	21	94	108	296	264	60	11	4	0	868
1975	0	0	0	11	130	267	357	394	86	18	0	0	1263
1976	0	0	9	30	26	193	257	205	46	4	0	0	770
1977	0	0	11	52	206	241	422	337	232	8	23	0	1532
1978	0	0	0	19	69	257	349	290	202	4	0	0	1190
1979	0	0	2	8	57	199	287	292	102	21	0	0	968
1980	0	0	0	4	87	210	438	415	199	17	0	0	1370
1981	0	0	1	29	43	270	341	267	109	2	0	0	1062
1982	0	0	0	4	171	121	383	252	101	62	9	7	1110

1983	0	0	4	3	27	248	465	487	219	21	0	0	1474
1984	0	0	0	17	50	340	254	312	141	44	1	0	1159
1985	0	0	5	40	67	189	317	245	155	49	4	0	1071
1986	0	0	4	34	115	285	427	269	197	42	0	0	1373
1987	0	0	0	10	212	304	383	395	173	2	5	0	1484
1988	0	0	1	8	81	306	442	407	120	5	0	0	1370
1989	0	0	8	34	66	214	362	296	146	27	0	0	1153
1990	0	0	13	29	32	239	326	285	168	26	5	0	1123
Avg	0	0	3	20	85	231	340	304	152	25	2	0	1167

'-999' = missing

Station: (154954) LOUISVILLE_WSO_AIRPORT, KY
From Year 1961 To 1990
Heating Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	1115	721	536	478	193	23	0	0	30	232	593	877	4798
1962	1065	720	694	385	16	0	0	0	95	224	617	1071	4887
1963	1200	968	476	231	109	1	0	1	71	86	493	1178	4814
1964	895	910	603	215	55	7	0	5	44	349	502	829	4414
1965	943	808	802	223	20	0	0	2	45	304	526	697	4370
1966	1170	857	580	353	127	8	0	0	35	324	531	907	4892
1967	882	949	453	209	139	13	0	0	68	259	660	788	4420
1968	1069	1007	590	247	98	4	0	1	10	276	511	903	4716
1969	987	778	771	213	61	14	0	0	42	282	645	971	4764
1970	1141	875	697	200	70	0	0	0	23	220	582	781	4589
1971	1052	833	707	303	137	0	0	0	13	65	537	610	4257
1972	914	866	623	282	61	19	0	0	16	298	628	793	4500
1973	927	796	349	343	129	0	0	0	13	144	450	860	4011
1974	772	714	487	257	99	19	0	0	122	314	543	794	4121
1975	830	688	665	333	22	0	0	0	73	205	431	801	4048
1976	1040	562	405	266	111	1	0	0	29	393	757	982	4546
1977	1435	780	421	183	36	7	0	0	6	295	472	935	4570
1978	1294	1145	720	221	142	1	0	0	4	293	442	765	5027
1979	1246	1030	514	301	94	5	0	0	19	244	534	792	4779
1980	969	1021	713	342	68	8	0	0	12	309	555	821	4818
1981	1065	728	595	142	122	0	0	0	61	268	523	960	4464
1982	1124	837	549	408	13	3	0	1	56	246	495	624	4356
1983	933	763	571	399	121	5	0	0	54	196	509	1128	4679
1984	1115	673	757	315	141	0	0	0	73	84	623	584	4365
1985	1222	896	458	180	52	16	0	0	53	160	347	1067	4451
1986	941	696	516	224	69	0	0	12	5	210	570	869	4112
1987	962	706	526	294	21	0	0	0	9	377	423	762	4080
1988	1048	872	580	244	38	7	0	0	13	398	510	833	4543
1989	720	860	513	291	156	4	0	0	49	230	539	1222	4584
1990	672	574	445	320	82	13	0	0	34	229	387	745	3501
Avg	1024	821	577	280	86	5	0	0	39	250	531	864	4482

'-999' = missing

Station: (154954) LOUISVILLE_WSO_AIRPORT, KY
From Year 1961 To 1990
Cooling Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	0	0	0	12	13	148	364	321	278	17	5	0	1158
1962	0	0	0	35	219	257	354	362	100	57	0	0	1384
1963	0	0	2	58	63	248	308	271	134	46	0	0	1130
1964	0	0	0	24	117	318	361	359	175	0	3	0	1357
1965	0	0	0	29	180	259	357	328	219	22	0	0	1394
1966	0	0	4	12	53	256	505	335	115	10	3	0	1293
1967	0	0	13	56	67	272	302	234	95	26	0	0	1065
1968	0	0	4	8	55	282	401	411	134	48	7	0	1350
1969	0	0	0	9	106	277	431	308	127	49	0	0	1307
1970	0	0	0	36	147	244	343	346	283	15	0	0	1414
1971	0	0	0	2	35	351	310	291	237	58	3	0	1287
1972	0	0	3	25	81	193	386	351	242	2	4	0	1287
1973	0	0	7	29	28	325	422	380	280	71	2	0	1544
1974	0	0	22	31	109	136	345	319	75	8	10	0	1055
1975	0	0	0	24	152	320	402	451	116	36	5	0	1506
1976	0	0	21	47	51	243	372	294	92	10	0	0	1130
1977	0	0	14	50	234	281	479	396	238	5	20	0	1717
1978	0	0	0	20	110	323	425	383	270	6	2	0	1539
1979	0	0	5	10	73	279	326	350	154	39	0	0	1236
1980	0	0	0	8	134	266	519	504	276	31	1	0	1739
1981	0	0	5	68	63	343	435	348	150	10	0	0	1422
1982	0	0	1	2	183	139	408	274	118	68	13	8	1214

1983	0	0	7	8	39	264	504	524	240	19	0	0	1605
1984	0	0	0	20	69	386	333	349	145	56	0	1	1359
1985	0	2	8	48	106	233	387	311	185	55	14	0	1349
1986	0	0	5	37	138	330	481	306	255	46	0	0	1598
1987	0	0	0	14	232	342	439	416	203	1	4	0	1651
1988	0	0	4	10	111	333	481	472	173	10	0	0	1594
1989	0	0	6	48	88	264	412	364	188	30	0	0	1400
1990	0	0	22	44	65	323	427	392	244	42	7	0	1566
Avg	0	0	5	27	104	274	400	358	184	29	3	0	1388

'-999' = missing

Station: (156110) PADUCAH_WSO, KY
From Year 1961 To 1990
Heating Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	1057	659	465	405	145	8	0	3	48	217	568	858	4433
1962	1026	677	699	342	10	0	2	0	57	183	570	978	4544
1963	1173	938	424	218	82	0	0	1	31	55	498	1158	4578
1964	879	840	557	165	43	5	0	4	41	297	467	808	4106
1965	872	766	805	176	8	0	0	1	41	256	404	663	3992
1966	1104	792	505	289	104	8	0	0	51	320	480	855	4508
1967	806	875	408	165	107	15	2	6	66	235	640	802	4127
1968	1025	979	582	215	80	0	0	0	12	273	551	885	4602
1969	935	753	773	214	44	4	0	0	18	257	613	936	4547
1970	1161	831	691	193	44	1	0	0	16	218	573	729	4457
1971	1004	779	669	262	105	0	1	0	20	58	515	601	4014
1972	905	764	546	232	45	4	1	0	15	251	642	879	4284
1973	907	780	326	296	84	0	0	0	17	133	380	877	3800
1974	820	677	411	238	48	4	0	0	81	228	503	822	3832
1975	803	735	690	281	17	0	0	0	97	186	427	789	4025
1976	994	529	351	230	116	1	0	0	23	364	749	945	4302
1977	1393	768	356	141	28	0	0	0	3	265	462	892	4308
1978	1272	1127	682	168	94	0	0	0	2	272	421	834	4872
1979	1261	978	511	258	80	0	0	1	22	200	563	764	4638
1980	896	939	674	265	53	0	0	0	20	284	542	807	4480
1981	1022	708	556	102	128	0	0	0	34	252	444	892	4138
1982	1111	835	462	343	14	1	0	0	37	220	503	629	4155
1983	947	689	553	411	80	2	0	0	50	135	456	1166	4489
1984	1105	659	656	269	82	0	0	0	69	108	591	611	4150
1985	1269	918	431	170	48	10	0	0	67	151	378	1037	4479
1986	909	688	475	173	47	0	0	8	3	191	589	863	3946
1987	968	671	451	249	7	0	0	0	12	356	419	735	3868
1988	1011	861	534	239	38	0	0	0	16	383	491	825	4398
1989	726	897	525	292	115	0	0	0	42	193	488	1165	4443
1990	651	534	438	313	89	10	0	1	28	273	352	771	3460
Avg	1000	788	540	243	66	2	0	0	34	227	509	852	4265

'-999' = missing

Station: (156110) PADUCAH_WSO, KY
From Year 1961 To 1990
Cooling Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	0	0	4	22	45	233	361	314	248	34	8	0	1269
1962	0	0	0	36	292	286	408	361	120	74	0	0	1577
1963	0	0	14	46	107	313	384	331	154	94	1	0	1444
1964	0	0	0	55	161	376	423	392	195	1	5	0	1608
1965	0	0	0	55	218	299	402	384	200	18	0	0	1576
1966	0	0	8	11	74	267	529	295	118	13	8	1	1324
1967	2	0	33	70	83	309	299	204	101	53	0	0	1154
1968	0	0	6	9	80	338	417	394	126	44	1	0	1415
1969	0	0	0	15	118	320	474	339	179	62	0	0	1507
1970	0	0	0	46	165	251	371	405	313	26	0	0	1577
1971	0	0	0	32	42	404	340	313	254	64	4	0	1453
1972	0	0	1	37	124	278	372	356	246	19	8	0	1441
1973	0	0	1	26	50	362	455	396	267	83	5	0	1645
1974	0	0	15	27	137	194	454	340	91	25	14	0	1297
1975	0	0	0	41	166	339	395	386	122	71	5	0	1525
1976	0	0	16	55	45	252	412	304	133	13	0	0	1230
1977	0	0	7	75	245	354	508	404	270	8	5	0	1876
1978	0	0	2	42	162	355	489	399	262	13	0	0	1724
1979	0	0	2	9	84	314	419	369	157	45	1	0	1400
1980	0	0	0	16	111	331	590	560	290	51	3	0	1952
1981	0	0	5	82	68	366	448	370	136	21	2	0	1498
1982	0	0	19	3	209	229	436	349	155	66	7	8	1481

1983	0	0	5	10	57	287	523	556	280	36	0	0	1754
1984	0	0	0	29	76	415	369	375	182	53	0	2	1501
1985	0	1	11	52	112	263	419	309	186	77	9	0	1439
1986	0	0	6	50	169	379	524	286	273	47	0	0	1734
1987	0	0	0	29	258	402	458	465	213	3	3	0	1831
1988	0	0	0	19	117	333	482	499	197	11	0	0	1658
1989	0	0	11	68	108	266	419	398	177	42	3	0	1492
1990	0	0	26	46	63	356	435	344	247	28	12	0	1557
Avg	0	0	6	37	124	315	433	373	196	39	3	0	1531

'-999' = missing

Station: (122738) EVANSVILLE_WSO_AP, IN
From Year 1961 To 1990
Heating Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	1097	706	472	384	149	11	0	1	44	208	582	948	4602
1962	1131	706	667	325	3	0	0	0	92	223	615	1075	4837
1963	1269	1008	471	250	112	0	0	0	44	84	532	1258	5028
1964	937	898	601	193	48	8	0	8	52	367	518	885	4515
1965	1008	867	867	254	18	0	0	5	39	283	500	727	4568
1966	1192	894	566	356	149	10	0	0	57	341	554	923	5042
1967	864	928	498	218	161	11	1	11	72	264	684	844	4556
1968	1128	997	595	256	111	5	0	0	15	292	569	946	4914
1969	1029	793	819	269	80	13	0	0	35	299	693	1034	5064
1970	1266	896	716	225	57	1	2	0	24	255	605	846	4893
1971	1087	874	707	290	90	0	0	0	23	85	571	701	4428
1972	1000	887	639	274	64	16	2	3	26	356	702	940	4909
1973	997	844	345	312	106	0	0	0	11	160	459	954	4188
1974	849	696	480	264	71	6	0	0	124	280	537	865	4172
1975	867	742	689	319	23	0	0	0	75	223	484	861	4283
1976	1100	628	417	275	139	0	0	0	27	391	786	1021	4784
1977	1549	867	428	162	32	4	0	0	3	289	495	970	4799
1978	1377	1228	774	233	137	0	0	0	10	323	473	865	5420
1979	1360	1125	559	326	106	0	0	1	28	290	619	813	5227
1980	982	1103	756	367	81	10	0	0	24	329	591	852	5095
1981	1090	771	624	161	155	0	0	0	53	256	498	940	4548
1982	1160	914	534	386	16	0	0	0	52	233	486	618	4399
1983	918	711	567	406	106	4	0	0	61	186	514	1195	4668
1984	1169	747	769	329	131	0	0	0	79	108	638	653	4623
1985	1276	985	411	208	55	9	0	0	75	185	446	1135	4785
1986	989	762	538	226	70	0	0	15	14	240	632	900	4386
1987	1007	735	528	330	19	0	0	0	15	423	456	777	4290
1988	1108	917	602	284	46	4	0	0	18	418	548	877	4822
1989	765	902	558	308	142	1	0	1	54	225	577	1297	4830
1990	707	603	487	358	97	15	2	1	35	291	432	828	3856
Avg	1075	857	589	284	85	4	0	1	42	263	559	918	4684

'-999' = missing

Station: (122738) EVANSVILLE_WSO_AP, IN
From Year 1961 To 1990
Cooling Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	0	0	2	21	47	226	387	320	269	22	10	0	1304
1962	0	0	0	57	300	291	402	363	113	51	0	0	1577
1963	0	0	3	42	68	292	369	309	130	62	0	0	1275
1964	0	0	0	41	138	332	398	340	159	0	0	0	1408
1965	0	0	0	36	172	267	354	308	186	9	0	0	1332
1966	0	0	7	12	37	273	525	300	78	12	2	0	1246
1967	0	0	13	66	63	276	268	175	114	36	0	0	1011
1968	0	0	4	13	62	296	402	391	123	48	2	0	1341
1969	0	0	0	8	85	300	448	307	140	48	0	0	1336
1970	0	0	0	43	169	220	329	331	286	18	0	0	1396
1971	0	0	0	28	49	437	382	367	260	53	0	0	1576
1972	0	0	2	21	99	214	337	285	196	2	4	0	1160
1973	0	0	0	23	35	331	438	396	265	76	3	0	1567
1974	0	0	26	28	141	188	452	292	73	14	15	0	1229
1975	0	0	0	29	176	342	406	388	129	29	1	0	1500
1976	0	0	6	47	40	258	379	274	98	10	0	0	1112
1977	0	0	9	61	255	323	501	376	232	6	16	0	1779
1978	0	0	0	16	125	361	444	366	229	7	2	0	1550
1979	0	0	0	13	65	310	365	312	138	35	0	0	1238
1980	0	0	0	5	102	264	535	521	257	39	3	0	1726
1981	0	0	1	69	50	355	425	343	128	15	3	0	1389
1982	0	0	10	3	198	179	458	290	134	59	9	11	1351

1983	0	0	3	8	42	303	514	532	236	17	0	0	1655
1984	0	0	0	16	60	416	348	349	127	49	0	0	1365
1985	0	3	13	36	108	276	447	319	190	58	5	0	1455
1986	0	0	2	27	156	360	487	265	246	32	0	0	1575
1987	0	0	0	8	235	350	420	408	201	0	1	0	1623
1988	0	0	0	11	113	329	441	436	162	8	0	0	1500
1989	0	0	3	64	96	272	403	369	161	28	0	0	1396
1990	0	0	21	29	43	318	387	336	220	23	3	0	1380
Avg	0	0	4	29	110	298	415	345	176	28	2	0	1411

'-999' = missing

Station: (406402) NASHVILLE_WSO_AIRPORT, TN
From Year 1961 To 1990
Heating Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	977	501	393	336	98	4	0	0	23	186	471	734	3723
1962	916	523	605	303	5	0	0	0	43	152	508	924	3979
1963	1050	855	358	170	63	0	0	0	28	48	465	1062	4099
1964	803	797	490	139	23	0	0	3	18	265	398	685	3621
1965	768	698	711	168	3	0	0	0	26	198	386	618	3576
1966	1007	657	452	234	78	7	0	0	13	255	423	763	3889
1967	697	763	300	106	69	1	0	3	58	216	615	688	3516
1968	952	941	531	205	64	1	0	0	4	220	484	825	4227
1969	855	700	692	149	38	3	0	0	10	201	551	854	4053
1970	1005	737	556	156	51	0	0	0	13	159	522	671	3870
1971	902	733	624	227	101	0	0	0	0	39	462	483	3571
1972	713	667	454	193	36	6	0	0	10	168	533	682	3462
1973	830	702	261	275	83	0	0	0	8	84	316	753	3312
1974	601	641	320	227	28	3	0	0	48	196	464	685	3213
1975	665	567	547	241	6	0	0	0	68	138	398	683	3313
1976	870	417	303	183	94	0	0	0	31	349	718	872	3837
1977	1250	679	350	129	28	1	0	0	3	255	425	813	3933
1978	1152	996	556	164	92	0	0	0	1	240	338	695	4234
1979	1088	877	449	213	57	0	0	0	5	180	487	723	4079
1980	777	848	571	240	38	0	0	0	9	259	487	739	3968
1981	909	621	537	97	96	0	0	0	42	175	445	820	3742
1982	956	707	416	309	8	0	0	0	30	194	413	537	3570
1983	806	620	458	322	71	0	0	0	45	121	447	956	3846
1984	1009	621	578	220	106	0	0	0	59	63	564	473	3693
1985	1146	794	383	145	25	6	0	0	30	91	264	948	3832
1986	854	561	432	171	55	0	0	3	0	175	447	773	3471
1987	889	608	401	242	6	0	0	0	7	317	376	640	3486
1988	941	756	485	242	43	2	0	0	5	343	408	693	3918
1989	618	721	397	258	90	0	0	0	36	158	408	1095	3781
1990	590	422	373	245	65	1	0	0	21	195	323	654	2889
Avg	886	691	466	210	54	1	0	0	23	188	451	751	3723

'-999' = missing

Station: (406402) NASHVILLE_WSO_AIRPORT, TN
From Year 1961 To 1990
Cooling Degree Days (Base:65F)

Yr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1961	0	0	2	26	63	234	390	361	286	30	18	0	1410
1962	0	0	0	41	327	308	442	461	178	92	0	0	1849
1963	0	0	17	76	142	336	398	372	185	71	1	0	1598
1964	0	0	0	71	177	387	433	386	214	15	6	0	1689
1965	0	0	0	53	216	312	429	442	305	28	0	0	1785
1966	0	0	7	55	93	316	540	366	156	16	3	0	1552
1967	1	0	59	78	115	347	340	245	118	48	0	0	1351
1968	0	0	5	24	110	304	403	460	158	58	2	0	1524
1969	0	0	0	33	165	378	554	416	191	74	0	0	1811
1970	0	0	0	56	163	265	386	446	374	40	1	1	1732
1971	0	0	0	23	55	380	374	360	293	101	16	1	1603
1972	0	0	1	62	117	250	385	387	341	24	6	0	1573
1973	0	0	14	25	61	339	432	412	351	128	8	0	1770
1974	0	0	16	39	191	203	410	399	130	30	22	0	1440
1975	3	0	3	55	183	341	424	444	164	62	19	0	1698
1976	0	1	28	36	68	257	363	299	92	10	0	0	1154
1977	0	0	11	74	253	371	543	458	281	13	4	0	2008
1978	0	0	1	50	152	344	489	432	324	13	2	0	1807
1979	0	0	11	5	103	264	393	381	175	44	0	0	1376
1980	0	0	0	17	131	322	562	527	344	44	1	0	1948
1981	0	0	1	71	81	383	464	366	145	42	0	0	1553
1982	0	0	37	4	199	256	470	352	177	84	12	21	1612

1983	0	0	9	12	69	320	488	568	315	49	2	0	1832
1984	0	0	0	21	87	382	352	364	173	121	0	1	1501
1985	0	2	24	59	137	335	479	386	206	79	29	0	1736
1986	0	0	1	52	174	352	551	371	304	59	0	0	1864
1987	0	0	0	31	272	381	479	507	227	3	7	0	1907
1988	0	0	5	17	120	380	515	531	246	17	0	0	1831
1989	0	0	21	93	120	298	446	408	208	39	8	0	1641
1990	0	4	26	51	115	401	485	458	315	52	10	0	1917
Avg	0	0	9	43	141	324	447	412	232	49	5	0	1669

'-999' = missing

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 100
Witness: Gary Smith

Data Request:

100. Refer to Mr. Smith's testimony on page 36. Please provide illustrative examples complete with calculations separately showing the WNA for the residential heating and man-heating customers under conditions 10 percent colder and warmer than normal.

Response:

Please reference the response to this Initial Attorney General Data Request, Item 49, for calculations of estimated WNA factors for conditions of 10 percent colder and warmer than normal weather.

The same WNA factor will be calculated applicable to all residential customers, both those with and without heating. Therefore, the only difference for those subsets of the residential class will be associated with the typical Mcf's of usage to which the WNA factor will apply.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 101
Witness: Smith

Data Request:

Reference P.S.C. Seventy-First Sheet No. 5. Please explain the basis for the different Expected Gas Cost Component for the various sales rates. Provide copies of documents which show how the various rates are derived and on what basis the differences are justified.

Response:

Refer to the attached GCA filing in Case No. 95-010 QQ. The EGC component comes from that GCA filing. Pages of the GCA filing are referenced in the calculation of the EGC.

The EGCs listed on page 5 are traced as follows:

G-1	Exhibit A, page 1 of 5, line 14
HLF G-1	Exhibit A, page 1 of 5, line 40
G-2	Exhibit A, page 2 of 5, line 13

The individual items listed on Exhibit A are traced as follows:

G-1	Commodity	Exhibit B, page 10 of 11, column 3, line 40
	Demand	Exhibit B, page 8 of 11, column 4, line 12
	Transition Costs	Exhibit B, page 9 of 11, column 3, line 11
HLF G-1	Commodity	Exhibit B, page 10 of 11, column 3, line 40
	Demand	Exhibit B, page 8 of 11, column 5, line 12
	Transition Costs	Exhibit B, page 9 of 11, column 3, line 11
G-2	Commodity	Exhibit B, page 10 of 11, column 3, line 40
	Demand	Exhibit B, page 8 of 11, column 5, line 12
	Transition Costs	Exhibit B, page 9 of 11, column 3, line 11

Western Kentucky Gas Company

WESTERN KENTUCKY GAS

February 26, 1999

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

Re: Case No. 95-010 QQ

Dear Ms. Helton:

We are filing the enclosed original and three (3) copies of a notice under the provisions of our monthly Gas Cost Adjustment Clause, Case No. 95-010 QQ.

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

Atmos Energy Corporation
377 Riverside Drive, Suite 202
Franklin, TN 37064

Also, please note that the service list on page 2 of the attached notice has changed.

If you have any questions, feel free to call me at 615-595-7700, ext. 231.

Sincerely,

John L. Baugh

John L. Baugh
Sr. Analyst - Rate Administration

JLB/jms

Enclosures

P.O. Box 650205 Dallas, Texas 75265-0205 972-934-9227

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

GAS COST ADJUSTMENT	)	Case No. 95-010 QQ
FILING OF	)	
WESTERN KENTUCKY GAS COMPANY	)	

NOTICE

MONTHLY FILING

For The Period

April 1, 1999 - April 30, 1999

Attorneys for Applicant

Mark R. Hutchinson
Sheffer-Hutchinson-Kinney
115 East Second Street
Owensboro, Kentucky 42303

and

John L. Baugh
Sr. Analyst - Rate Administration
Atmos Energy Corporation
377 Riverside Drive, Suite 202
Franklin, Tennessee 37064

February 26, 1999

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

Conrad Gruber
President
Western Kentucky Gas Company
Post Office Box 866
Owensboro, Kentucky 42302

William J. Senter
Vice President - Rates & Regulatory Affairs
Western Kentucky Gas Company
Post Office Box 866
Owensboro, Kentucky 42302

Mark R. Hutchinson
Attorney for Applicant
Sheffer-Hutchinson-Kinney
115 East Second Street
Owensboro, Kentucky 42303

John L. Baugh
Sr. Analyst - Rate Administration
Atmos Energy Corporation
377 Riverside Drive, Suite 202
Franklin, Tennessee 37064

The Company gives notice to the Kentucky Public Service Commission, hereinafter "the Commission", pursuant to the monthly Gas Cost Adjustment Clause contained in the Company's settlement gas rate schedules in Case No. 95-010.

The Company hereby files Sixty-eighth Revised Sheet No. 4, Sixty-eighth Revised Sheet No. 5 and Sixty-eighth Revised Sheet No. 6 to its PSC No. 20, Rates, Rules and Regulations for Furnishing Natural Gas to become effective April 1, 1999.

The Gas Cost Adjustment (GCA) for firm sales service is $(0.9286) per Mcf, $(1.4835) per Mcf for high load factor firm sales service, and $(0.6693) per Mcf for interruptible sales service. The supporting calculations for the Sixty-eighth Revised Sheet No. 5 are provided in the following Exhibits:

Exhibit A - Summary of Derivations of Gas Cost Adjustment (GCA) .. Tab 3
Exhibit B - Expected Gas Cost (EGC) Calculation .... Tab 4
Exhibit C - Rates used in the Expected Gas Cost (EGC) Calculation Tab 5
Exhibit D - Correction Factor (CF) Calculation .... Tab 6
Exhibit E - Refund Plan Certificate of Compliance .... Tab 7
Exhibit F - LVS Pricing Calculation .... Tab 8

Since the Company's last GCA filing, Case No. 95-010 PP, the following changes have occurred in its pipeline and gas supply commodity rates for the GCA period.

1. The commodity rates per MMbtu used are based on historical estimates and/or current data for April, 1999, as shown in Exhibit C, page 12.

2. The Expected Commodity Gas Cost will be approximately $1.75 per MMbtu for April, 1999, as compared to $1.77 per MMbtu used for March, 1999.

3. The Company's notice sets out a new six-month Correction Factor (CF) of $(0.1882) per Mcf, which will remain in effect until October 1, 1999.

4. A refund in the amount of $1,118,977.25 was received from Texas Gas Transmission on January 18, 1999. This refund represents the difference between the base tariff settlement rates approved in Docket No. RP97-344 and the base tariff rates actually invoiced. The carry-over amount of a previous refund (Case No. 95-010 CC) is also included in the calculation of a new refund factor, which is detailed on Exhibit E.

The GCA tariff as approved in Case No. 92-558 provides for a Correction Factor (CF) which compensates for the difference between the expected gas cost and the actual gas cost for prior periods. The Company is filing its updated Correction Factor that is based upon the balance in the Company's Account 191 as of December 31, 1998, to be effective for the six-month period April, 1999 through September, 1999. The calculation for the Correction Factor is detailed on Exhibit D.

WHEREFORE, Western Kentucky Gas Company requests this Commission, pursuant to the Commission's order in Case No. 95-010, to approve the Gas Cost Adjustment (GCA) as filed in Sixty-eighth Revised Sheet No. 5; and Sixty-eighth Revised Sheet No. 6 setting out the General Transportation Tariff Rate T-2 for each respective sales rate for meter readings made on and after April 1, 1999.

DATED at Franklin, Tennessee, this 26th Day of February, 1999.

WESTERN KENTUCKY GAS COMPANY

By: John L. Baugh

John L. Baugh, Esq., CPA
Sr. Analyst - Rate Administration
Atmos Energy Corporation

SUBSCRIBED AND SWORN TO before me by John L. Baugh, this 26th Day of February, 1999.

Lois Carner
Notary Public, State of Tennessee

My Commission Expires: July 24, 1999

WESTERN KENTUCKY GAS COMPANY

Current Rate Summary

Case No. 95-010 QQ

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	@ 3.5660 per Mcf	@ 1.7902 per Mcf	@ 1.0615 per Mcf	(I, R, N)
Next	14,700 [1]	Mcf	@ 3.0630 per Mcf	@ 1.2872 per Mcf	@ 0.5585 per Mcf	(I, R, N)
Over	15,000	Mcf	@ 2.9130 per Mcf	@ 1.1372 per Mcf	@ 0.4085 per Mcf	(I, R, N)

High Load Factor Firm Service

			Sales	Transport	
HLF demand charge/Mcf			@ 4.2809	@ 4.2809 per Mcf of daily Contract Demand	(N)
First	300 [1]	Mcf	@ 3.0111 per Mcf	@ 1.2353 per Mcf	(I, R)
Next	14,700 [1]	Mcf	@ 2.5081 per Mcf	@ 0.7323 per Mcf	(I, R)
Over	15,000	Mcf	@ 2.3581 per Mcf	@ 0.5823 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	@ 2.4756 per Mcf	@ 0.6998 per Mcf	@ 0.4936 per Mcf	(I, R, N)
Over	15,000	Mcf	@ 2.3256 per Mcf	@ 0.5498 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: February 26, 1999 Effective: April 1, 1999

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

ISSUED BY: Vice President - Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Current Gas Cost Adjustments

Case No. 95-010 QQ

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)	2.7334	2.1785	2.1785	(R, R, R)
BCOG (Base Cost of Gas)	3.4331	3.4331	2.6513	
EGC - BCOG	(0.6997)	(1.2546)	(0.4728)	(R, R, R)
CF (Correction Factor)	(0.1882)	(0.1882)	(0.1882)	(I, I, I)
RF (Refund Adjustment)	(0.0654)	(0.0654)	(0.0330)	(R, R, R)
PBRRF (Peformanced Based Rate Recovery Factor)	0.0247	0.0247	0.0247	(N, N, N)
GCA (Gas Cost Adjustment)	($0.9286)	($1.4835)	($0.6693)	(I, I, I)

ISSUED: February 26, 1999 Effective: April 1, 1999

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

ISSUED BY: Vice President - Rates & Regulatory Affairs

WESTERN KENTUCKY GAS COMPANY

Current Transportation and Carriage

Case No. 95-010 QQ

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	+	$0.7287	=	$1.7902	per Mcf	(R)
Next	14,700 [2]	Mcf	@		0.5585	+	0.7287	=	1.2872	per Mcf	(R)
All over	15,000	Mcf	@		0.4085	+	0.7287	=	1.1372	per Mcf	(R)
b) High Load Factor Firm Service (HLF)											
Demand			@		$0.0000	+	4.2809	=	$4.2809	per Mcf of daily contract demand	(N)
First	300 [2]	Mcf	@		$1.0615	+	$0.1738	=	$1.2353	per Mcf	(R)
Next	14,700 [2]	Mcf	@		0.5585	+	0.1738	=	0.7323	per Mcf	(R)
All over	15,000	Mcf	@		0.4085	+	0.1738	=	0.5823	per Mcf	(R)
c) Interruptible Service											
First	15,000 [2]	Mcf	@		$0.4936	+	$0.2062	=	$0.6998	per Mcf	(R)
All over	15,000	Mcf	@		0.3436	+	0.2062	=	0.5498	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: February 26, 1999 Effective: April 1, 1999

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

ISSUED BY: Vice President - Rates & Regulatory Affairs

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Firm Sales Service

Line No.	Description	Case No. 95-010 PP $/Mcf	Case No. 95-010 QQ $/Mcf	Difference $/Mcf
1	G-1			
2				
3	Commodity Charge (Base Rate per Case No. 95-010):			
4	First 300 Mcf	4.4946	4.4946	0.0000
5	Next 14,700 Mcf	3.9916	3.9916	0.0000
6	Over 15,000 Mcf	3.8416	3.8416	0.0000
7				
8	Gas Cost Adjustment Components			
9	EGC (Expected Gas Cost):			
10	Commodity	2.0348	1.9605	(0.0743)
11	Demand	0.7543	0.7543	0.0000
12	Take-Or-Pay	0.0000	0.0000	0.0000
13	Transition Costs	0.0186	0.0186	0.0000
14	Total EGC	2.8077	2.7334	(0.0743)
15	Less: BCOG (Base Cost of Gas)	3.4331	3.4331	0.0000
16	CF (Correction Factor)	(0.3110)	(0.1882)	0.1228
17	RF (Refund Adjustment)	(0.0225)	(0.0654)	(0.0429)
18	PBRRF (Performance Based Rate Recovery Factor)	0.0247	0.0247	0.0000
19	GCA (Gas Cost Adjustment)	(0.9342)	(0.9286)	0.0056
20	Total Billing Cost of Gas	2.4989	2.5045	0.0056
21				
22	Commodity Charge (GCA included):			
23	First 300 Mcf	3.5604	3.5660	0.0056
24	Next 14,700 Mcf	3.0574	3.0630	0.0056
25	Over 15,000 Mcf	2.9074	2.9130	0.0056
26				
27	HLF (High Load Factor)			
28				
29	Commodity Charge (Base Rate per Case No. 95-010):			
30	First 300 Mcf	4.4946	4.4946	0.0000
31	Next 14,700 Mcf	3.9916	3.9916	0.0000
32	Over 15,000 Mcf	3.8416	3.8416	0.0000
33				
34	Gas Cost Adjustment Components			
35	EGC (Expected Gas Cost):			
36	Commodity	2.0348	1.9605	(0.0743)
37	Demand	0.1994	0.1994	0.0000
38	Take-Or-Pay	0.0000	0.0000	0.0000
39	Transition Costs	0.0186	0.0186	0.0000
40	Total EGC	2.2528	2.1785	(0.0743)
41	Less: BCOG (Base Cost of Gas)	3.4331	3.4331	0.0000
42	CF (Correction Factor)	(0.3110)	(0.1882)	0.1228
43	RF (Refund Adjustment)	(0.0225)	(0.0654)	(0.0429)
44	PBRRF (Perfomace Based Rate Recovery Factor)	0.0247	0.0247	0.0000
45	GCA (Gas Cost Adjustment)	(1.4891)	(1.4835)	0.0056
46	Total Cost of Gas to Bill (excludes MDQ Demand)	1.9440	1.9496	0.0056
47				
48	Commodity Charge (GCA included):			
49	First 300 Mcf	3.0055	3.0111	0.0056
50	Next 14,700 Mcf	2.5025	2.5081	0.0056
51	Over 15,000 Mcf	2.3525	2.3581	0.0056
52				
53	HLF Demand			
54	Contract Demand Factor	4.2809	4.2809	0.0000

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Interruptible Sales Service

Line No.	Description	Case No. 95-010 PP	95-010 QQ	Difference
		$/Mcf	$/Mcf	$/Mcf
1	G-2			
2				
3	Commodity Charge (Base Rate per Case No. 95-010):			
4	First 15,000 Mcf	3.1449	3.1449	0.0000
5	Over 15,000 Mcf	2.9949	2.9949	0.0000
6				
7	Gas Cost Adjustment Components			
8	Expected Gas Cost (EGC):			
9	Commodity	2.0348	1.9605	(0.0743)
10	Demand	0.1994	0.1994	0.0000
11	Take-Or-Pay	0.0000	0.0000	0.0000
12	Transition Costs	0.0186	0.0186	0.0000
13	Total EGC	2.2528	2.1785	(0.0743)
14	Less: Base Cost of Gas (BCOG)	2.6513	2.6513	0.0000
15	Correction Factor (CF)	(0.3110)	(0.1882)	0.1228
16	Refund Adjustment (RF)	(0.0203)	(0.0330)	(0.0127)
17	Perfomace Based Rate Recovery Factor (PBRRF)	0.0247	0.0247	0.0000
18	Gas Cost Adjustment (GCA)	(0.7051)	(0.6693)	0.0358
19	Total Cost of Gas to Bill	1.9462	1.9820	0.0358
20				
21	Commodity Charge (GCA included):			
22	First 15,000 Mcf	2.4398	2.4756	0.0358
23	Over 15,000 Mcf	2.2898	2.3256	0.0358
24				
25				

Line No.		Case No.	Effective Date	G - 1	G - 1 / HLF	G - 2
26	Monthly Refund Factor					
27						
28						
29	1 -	95-010 FF	05/01/98	0.0000	0.0000	0.0000
30	2 -	95-010 GG	06/01/98	0.0000	0.0000	0.0000
31	3 -	95-010 HH	07/01/98	(0.0095)	(0.0095)	(0.0073)
32	4 -	95-010 II	08/01/98	0.0000	0.0000	0.0000
33	5 -	95-010 JJ	09/01/98	0.0000	0.0000	0.0000
34	6 -	95-010 KK	10/01/98	(0.0130)	(0.0130)	(0.0130)
35	7 -	95-010 LL	11/01/98	0.0000	0.0000	0.0000
36	8 -	95-010 MM	12/01/98	0.0000	0.0000	0.0000
37	9 -	95-010 NN	01/01/99	0.0000	0.0000	0.0000
38	10 -	95-010 OO	02/01/99	0.0000	0.0000	0.0000
39	11 -	95-010 PP	03/01/99	0.0000	0.0000	0.0000
40	12 -	95-010 QQ	04/01/99	(0.0429)	(0.0429)	(0.0127)
41						
42	Total Supplier Refund Adjustment (RF)			(0.0654)	(0.0654)	(0.0330)
43						

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description			Case No. 95-010 PP	Case No. 95-010 QQ	Difference
				$/Mcf	$/Mcf	$/Mcf
1	T-2 \ G-1					
2						
3						
4	Simple Margin (Base Rate per Case No. 95-010)::					
5	First	300	Mcf	1.0615	1.0615	0.0000
6	Next	14,700	Mcf	0.5585	0.5585	0.0000
7	Over	15,000	Mcf	0.4085	0.4085	0.0000
8						
9	Non-Commodity Components:					
10	Demand			0.7543	0.7543	0.0000
11	Take-Or-Pay			0.0000	0.0000	0.0000
12	Transition Costs			0.0186	0.0186	0.0000
13	RF (Refund Adjustment)			(0.0030)	(0.0442)	(0.0412)
14	Total			0.7699	0.7287	(0.0412)
15						
16	Gross Margin:					
17	First	300	Mcf	1.8314	1.7902	(0.0412)
18	Next	14,700	Mcf	1.3284	1.2872	(0.0412)
19	Over	15,000	Mcf	1.1784	1.1372	(0.0412)
20						
21	T-2\G-1\HLF					
22						
23	Simple Margin (Base Rate per Case No. 95-010):					
24	First	300	Mcf	1.0615	1.0615	0.0000
25	Next	14,700	Mcf	0.5585	0.5585	0.0000
26	Over	15,000	Mcf	0.4085	0.4085	0.0000
27						
28	Non-Commodity Components:					
29	Demand			0.1994	0.1994	0.0000
30	Take-Or-Pay			0.0000	0.0000	0.0000
31	Transition Costs			0.0186	0.0186	0.0000
32	RF (Refund Adjustment)			(0.0030)	(0.0442)	(0.0412)
33	Total			0.2150	0.1738	(0.0412)
34						
35	Gross Margin (Excluding HLF Demand):					
36	First	300	Mcf	1.2765	1.2353	(0.0412)
37	Next	14,700	Mcf	0.7735	0.7323	(0.0412)
38	Over	15,000	Mcf	0.6235	0.5823	(0.0412)
39						
40	HLF Demand					
41	Contract Demand Factor			4.2809	4.2809	0.0000
42						

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Firm Transportation Service

Line No.	Description			Case No. 95-010 PP	95-010 QQ	Difference
				$/Mcf	$/Mcf	$/Mcf
1	Carriage Service					
2						
3	Firm Service (T-4)					
4	Simple Margin (Base Rate per Case No. 95-010):					
5	First	300	Mcf	1.0615	1.0615	0.0000
6	Next	14,700	Mcf	0.5585	0.5585	0.0000
7	Over	15,000	Mcf	0.4085	0.4085	0.0000
8						
9	Non-Commodity Components:					
11	Take-Or-Pay			0.0000	0.0000	0.0000
13	RF (Refund Adjustment)			0.0000	0.0000	0.0000
14	Total			0.0000	0.0000	0.0000
15						
16	Gross Margin:					
17	First	300	Mcf	1.0615	1.0615	0.0000
18	Next	14,700	Mcf	0.5585	0.5585	0.0000
19	Over	15,000	Mcf	0.4085	0.4085	0.0000
20						

Western Kentucky Gas Company
Comparison of Current and Previous Cases
Interruptible Transportation and Carriage Service

Line No.	Description			Case No. 95-010 PP	Case No. 95-010 QQ	Difference
				$/Mcf	$/Mcf	$/Mcf
1	General Transporation (T-2)					
2						
3	Interruptible Service (G-2)					
4	Simple Margin (Base Rate per Case No. 95-010):					
5	First	15,000	Mcf	0.4936	0.4936	0.0000
6	Over	15,000	Mcf	0.3436	0.3436	0.0000
7						
8	Non-Commodity Components:					
9	Demand			0.1994	0.1994	0.0000
10	Take-Or-Pay			0.0000	0.0000	0.0000
11	Transition Costs			0.0186	0.0186	0.0000
12	RF (Refund Adjustment)			(0.0008)	(0.0118)	(0.0110)
13	Total			0.2172	0.2062	(0.0110)
14						
15	Gross Margin:					
16	First	15,000	Mcf	0.7108	0.6998	(0.0110)
17	Over	15,000	Mcf	0.5608	0.5498	(0.0110)
18						
19	Carriage Service					
20						
21	Carriage Service (T-3)					
22	Simple Margin (Base Rate per Case No. 95-010):					
23	First	15,000	Mcf	0.4936	0.4936	0.0000
24	Over	15,000	Mcf	0.3436	0.3436	0.0000
25						
26	Non-Commodity Components:					
28	Take-Or-Pay			0.0000	0.0000	0.0000
30	RF (Refund Adjustment)			0.0000	0.0000	0.0000
31	Total			0.0000	0.0000	0.0000
32						
33	Gross Margin:					
34	First	15,000	Mcf	0.4936	0.4936	0.0000
35	Over	15,000	Mcf	0.3436	0.3436	0.0000
36						

Western Kentucky Gas Company

Expected Gas Cost - Non Commodity

Texas Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	SL to Zone 2							
2	NNS Contract #	N0210		12,617,673				
3	Base Rate		10		0.3158	3,984,660	3,984,660	
4	GSR		10		0.0000	0		0
5	TCA Adjustment		10		0.0000	0	0	
6	Unrec TCA Surch		10		0.0000	0	0	
7	ISS Credit		10		0.0000	0	0	
8	Misc Rev Cr Adj		10		(0.0001)	(1,262)	(1,262)	
9	GRI		10		0.0085	107,250	107,250	
6								
7	Total SL to Zone 2			12,617,673		4,090,648	4,090,648	0
8								
9	SL to Zone 3							
10	NNS Contract #	N0340		27,480,375				
11	Base Rate		10		0.3498	9,612,635	9,612,635	
12	GSR		10		0.0000	0		0
13	TCA Adjustment		10		0.0000	0	0	
14	Unrec TCA Surch		10		0.0000	0	0	
15	ISS Credit		10		0.0000	0	0	
16	Misc Rev Cr Adj		10		(0.0001)	(2,748)	(2,748)	
17	GRI		10		0.0085	233,583	233,583	
18								
19	FT Contract #	3355		2,488,935				
20	Base Rate		11		0.2529	629,452	629,452	
21	GSR		11		0.0000	0		0
22	TCA Adjustment		11		0.0000	0	0	
23	Unrec TCA Surch		11		0.0000	0	0	
24	ISS Credit		11		(0.0007)	(1,742)	(1,742)	
25	Misc Rev Cr Adj		11		(0.0001)	(249)	(249)	
26	GRI		11		0.0085	21,156	21,156	
27								
28								
29	Total SL to Zone 3			29,969,310		10,492,087	10,492,087	0
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								

Western Kentucky Gas Company
Expected Gas Cost - Non Commodity
Texas Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	<u>Zone 1 to Zone 3</u>							
2	FT Contract #	3355		1,863,690				
3	Base Rate		11		0.2448	456,231	456,231	
4	GSR		11		0.0000	0		0
5	TCA Adjustment		11		0.0000	0	0	
6	Unrec TCA Surch		11		0.0000	0	0	
7	ISS Credit		11		(0.0007)	(1,305)	(1,305)	
8	Misc Rev Cr Adj		11		(0.0001)	(186)	(186)	
9	GRI		11		0.0085	15,841	15,841	
6								
7	Total Zone 1 to Zone 3			1,863,690		470,581	470,581	0
8								
9	<u>SL to Zone 4</u>							
10	NNS Contract #	N0410		3,320,769				
11	Base Rate		10		0.4096	1,360,187	1,360,187	
12	GSR		10		0.0000	0		0
13	TCA Adjustment		10		0.0000	0	0	
14	Unrec TCA Surch		10		0.0000	0	0	
15	ISS Credit		10		0.0000	0	0	
16	Misc Rev Cr Adj		10		(0.0001)	(332)	(332)	
17	GRI		10		0.0085	28,227	28,227	
18								
19	FT Contract #	3819		1,277,500				
20	Base Rate		11		0.3061	391,043	391,043	
21	GSR		11		0.0000	0		0
22	TCA Adjustment		11		0.0000	0	0	
23	Unrec TCA Surch		11		0.0000	0	0	
24	ISS Credit		11		(0.0007)	(894)	(894)	
25	Misc Rev Cr Adj		11		(0.0001)	(128)	(128)	
26	GRI		11		0.0085	10,859	10,859	
27								
28	Total SL to Zone 4			4,598,269		1,788,962	1,788,962	0
29								
30	Total SL to Zone 2			12,617,673		4,090,648	4,090,648	0
31	Total SL to Zone 3			29,969,310		10,492,087	10,492,087	0
32	Total Zone 1 to Zone 3			1,863,690		470,581	470,581	0
33								
34	Total Texas Gas			49,048,942		16,842,278	16,842,278	0
35								
36								
37	Vendor Reservation Fees (Fixed)					166,842	166,842	
38								
39	TOP & Direct Billed Transition costs					0		
40								
41	Total Texas Gas Area Non-Commodity					17,009,120	17,009,120	0
42								
43								

Western Kentucky Gas Company

Expected Gas Cost - Non Commodity

Tennessee Gas

Line No.	Description		Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Non-Commodity Transition Costs
				MMbtu	$/MMbtu	$	$	$
1	0 to Zone 2							
2	FT-G Contract #	2546.1		12,846	11.0600			
3	Base Rate		23B		9.0800	116,642	116,642	
4	Settlement Surcharge		23B		1.6300	20,939		20,939
5	PCB Adjustment		23B		0.3500	4,496		4,496
6								
7	FT-G Contract #	2548.1		4,361	11.0600			
8	Base Rate		23B		9.0800	39,598	39,598	
9	Settlement Surcharge		23B		1.6300	7,108		7,108
10	PCB Adjustment		23B		0.3500	1,526		1,526
11								
12	FT-G Contract #	2550.1		5,739	11.0600			
13	Base Rate		23B		9.0800	52,110	52,110	
14	Settlement Surcharge		23B		1.6300	9,355		9,355
15	PCB Adjustment		23B		0.3500	2,009		2,009
16								
17	FT-G Contract #	2551.1		4,446	11.0600			
18	Base Rate		23B		9.0800	40,370	40,370	
19	Settlement Surcharge		23B		1.6300	7,247		7,247
20	PCB Adjustment		23B		0.3500	1,556		1,556
21								
22								
23	Total Zone 0 to 2			27,392		302,956	248,720	54,236
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								

Western Kentucky Gas Company
Expected Gas Cost - Non Commodity
Tennessee Gas

Line No.	Description	Tariff Sheet No.	(1) Annual Units	(2) Rate	(3) Non-Commodity Total	(4) Non-Commodity Demand	(5) Transition Costs
			MMbtu	$/MMbtu	$	$	$
1	1 to Zone 2						
2	FT-G Contract # 2546		114,154	9.5700			
3	Base Rate	23B		7.6300	870,995	870,995	
4	Settlement Surcharge	23B		1.6300	186,071		186,071
5	PCB Adjustment	23B		0.3100	35,388		35,388
6							
7	FT-G Contract # 2548		44,999	9.5700			
8	Base Rate	23B		7.6300	343,342	343,342	
9	Settlement Surcharge	23B		1.6300	73,348		73,348
10	PCB Adjustment	23B		0.3100	13,950		13,950
11							
12	FT-G Contract # 2550		59,741	9.5700			
13	Base Rate	23B		7.6300	455,824	455,824	
14	Settlement Surcharge	23B		1.6300	97,378		97,378
15	PCB Adjustment	23B		0.3100	18,520		18,520
16							
17	FT-G Contract # 2551		45,059	9.5700			
18	Base Rate	23B		7.6300	343,800	343,800	
19	Settlement Surcharge	23B		1.6300	73,446		73,446
20	PCB Adjustment	23B		0.3100	13,968		13,968
21							
22	Total Zone 1 to 2		263,953		2,526,030	2,013,961	512,069
23							
24	Total Zone 0 to 2		27,392		302,956	248,720	54,236
25							
26	Total Zone 1 to 2 and Zone 0 to 2		291,345		2,828,986	2,262,681	566,305
27							
28	Gas Storage						
29	Production Area:						
30	Demand	27	34,968	2.0200	70,635	70,635	
31	Space Charge	27	4,916,148	0.0248	121,920	121,920	
32	Market Area:						
33	Demand	27	237,408	1.1700	277,767	277,767	
34	Space Charge	27	10,846,308	0.0187	202,826	202,826	
35	Total Storage				673,148	673,148	
36							
37	Vendor Reservation Fees (Fixed)				94,151	94,151	
38							
39	TOP & Direct Billed Transition costs				0	0	0
40							
41	Total Tennessee Gas Area FT-G Non-Commodity				3,596,285	3,029,980	566,305
42							
43							
44							
45							
46							
47							
48							
49							
50							
51							

Western Kentucky Gas Company

Expected Gas Cost - Commodity

Purchases in Texas Gas Service Area

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	No Notice Service				1,830,213		
2	Indexed Gas Cost					1.7500	3,202,873
3	Commodity	10				0.0392	71,744
4	Fuel and Loss Retention @	14	3.12%			0.0564	103,224
5						1.8456	3,377,841
6							
7	Firm Transportation				258,500		
8	Indexed Gas Cost					1.7500	452,375
9	Base (Weighted on MDQs)	11A				0.0297	7,677
10	TCA Adjustment	11A				(0.0072)	(1,861)
11	Unrecovered TCA Surcharge	11A				0.0000	0
12	Cash-out Adjustment	11A				0.0000	0
13	GRI	11A				0.0088	2,275
14	ACA	11A				0.0018	465
15	Fuel and Loss Retention @	14	2.78%			0.0500	12,925
16						1.8331	473,856
17	No Notice Storage						
18	Net (Injections)/Withdrawals				(156,000)		
19	Indexed Gas Cost					1.7500	(273,000)
20	Commodity (Zone 3)	10				0.0392	(6,115)
21	Fuel and Loss Retention @	14	3.12%			0.0564	(8,798)
22						1.8456	(287,913)
23							
24							
25	Total Purchases in Texas Area				1,932,713	1.8439	3,563,784
26							
27							

28 Used to allocate transportation non-commodity

Line No.		Annualized MDQs in MMbtu	Allocation	Commodity Charge $/MMbtu	Weighted Average
29					
30					
31					
32	Texas Gas				
33	SL to Zone 2	12,617,673	25.72%	$0.0260	$ 0.0067
34	SL to Zone 3	29,969,310	61.11%	0.0307	0.0188
35	1 to Zone 3	1,863,690	3.80%	0.0290	0.0011
36	SL to Zone 4	4,598,269	9.37%	0.0335	0.0031
37	Total	49,048,942	100.00%		$ 0.0297
38					
39	Tennessee Gas				
40	0 to Zone 2	27,392	9.40%	0.0881	$ 0.0083
41	1 to Zone 2	263,953	90.60%	0.0776	0.0703
42	Total	291,345	100.00%		$ 0.0786
43					

Western Kentucky Gas Company
Expected Gas Cost - Commodity
Purchases in Tennessee Gas Service Area

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	FT-A and FT-G				310,128		
2	Indexed Gas Cost					1.7500	542,724
3	Base Commodity (Weighted on MDQs)					0.0786	24,376
4	GRI	23C				0.0200	6,203
5	ACA	23C				0.0022	682
6	Transition Cost	23C				0.0225	6,978
7	Fuel and Loss Retention	29	3.69%			0.0670	20,779
8						1.9403	601,742
9							
10							
11	FT-GS				76,778		
12	Indexed Gas Cost					1.7500	134,362
13	Base Rate	20				0.5856	44,961
14	GRI	20				0.0200	1,536
15	ACA	20				0.0022	169
16	PCB Adjustment	20				0.0192	1,474
17	Settlement Surcharge	20				0.0893	6,856
18	Fuel and Loss Retention	29	3.69%			0.0670	5,144
19						2.5333	194,502
20							
21							
22	Gas Storage						
23	FT-A & FT-G Market Area (Injections)/Withdrawals				(100,750)		
24	Indexed Gas Cost	(Line 8 - Line 7)				1.8733	(188,735)
25	Injection Rate	27				0.0102	(1,028)
26	Fuel and Loss Retention	27	1.49%			0.0283	(2,851)
27	Total					1.9118	(192,614)
28							
29							
30	FT-GS Market Area (Injections)/Withdrawals				(29,250)		
31	Indexed Gas Cost	(Line 19- Line 18)				2.4663	(72,139)
32	Injection Rate	27				0.0102	(298)
33	Fuel and Loss Retention	27	1.49%			0.0373	(1,091)
34	Total					2.5138	(73,528)
35							
36							
37	Total Tennessee Gas Zones				256,906	2.0634	530,102
38							
39							

Western Kentucky Gas Company

Expected Gas Cost
Trunkline Gas

Commodity

Line No.	Description	Tariff Sheet No.		(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	Firm Transportation						
2	Expected Volumes				75,000		
3	Indexed Gas Cost					1.7500	131,250
4	Base Commodity					0.0251	1,883
5	GRI	6				0.0088	660
6	ACA	6				0.0019	143
7	Fuel and Loss Retention	6	1.18%			0.0209	1,568
8						1.8067	135,504
9							
10							

Non-Commodity

Line No.	Description	(1) Tariff Sheet No.	(2) Annual Units MMbtu	(3) Non-Commodity Rate $/MMbtu	(4) Non-Commodity Total $	(5) Non-Commodity Demand $	(6) Non-Commodity Transition Costs $
11	FT-G Contract # 014573		2,032,600				
12	Discount Rate on MDQs			0.2580	524,411	524,411	
13							
14			67,000				
15	GRI Surcharge	6		0.2600	17,420	17,420	
16							
17	Reservation Fee				20,480	20,480	
18							
19	Total Trunkline Area Non-Commodity				562,311	562,311	
20							
21							

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Total Demand Cost:						
2	Texas Gas	$16,842,278					
3	Reservation Fees (Fixed)	166,842					
4	Tennessee Gas	3,029,980					
5	Trunkline	562,311					
6	Total	$20,601,411					
7							
8			Allocated	Related	Monthly Demand Charge		
9	Demand Cost Allocation:	Factors	Demand	Volumes	Firm	Interruptible	HLF
10	All	0.2943	$6,062,995	30,400,000	0.1994	0.1994	0.1994
11	Firm	0.7057	14,538,416	26,200,000	0.5549	NA	NA
12	Total	1.0000	$20,601,411		0.7543	0.1994	0.1994
13							
14			Volumetric Basis for				
15		Annualized	Monthly Demand Charge				
16		Mcf @14.65	All	Firm			
17	Firm Service						
18	Sales:						
19	G-1	24,200,000	24,200,000	24,200,000	0.7543		
20	HLF	300,000	300,000		0.1994 + HLF MDQ Demand		
21	LVS-1	1,500,000	1,500,000	1,500,000	0.7543		
22	Total Firm Sales	26,000,000	26,000,000	25,700,000			
23							
24	Transportation:						
25	T-2 \ G-1	500,000	500,000	500,000	0.7543		
26	HLF	0	0		0.1994		
27	Total Firm Service	26,500,000	26,500,000	26,200,000			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	2,000,000	2,000,000		0.7543	0.1994	
32	LVS-2	1,200,000	1,200,000		0.7543	0.1994	
33	Total Sales	3,200,000	3,200,000				
34							
35	Transportation:						
36	T-2 \ G-2	700,000	700,000		0.7543	0.1994	
37							
38	Total Interruptible Service	3,900,000	3,900,000				
39							
40	Carriage Service						
41	T-3 & T-4	20,100,000					
42							
43	Total	50,500,000	30,400,000	26,200,000			
44							
45	HLF MDQ Demand						
46	Firm Demand Cost		$14,538,416				
47	Peak Day Thru-put		283,011	Mcf/Peak Day			
48	Times:		12	Months/Year			
49	Total Annualized Peak Day Demand		3,396,132				
50	Demand Charge per MDQ		$4.2809	/ MDQ of Customer's Contract			
51							
52							
53	Note: LVS Credit =	($1,370,730)					

Western Kentucky Gas Company
Take-or-Pay and Transition Charge Calculation

Line No.		(1)	(2)	(3)	(4)	(5)	(6)
1	Other Fixed Charges	Take-or-Pay	Transition				
2	Texas Gas		$0				
3	Tennessee Gas		566,305				
4	Total	$0	$566,305				
5							
6							
7			Related	Charge			
8	Other Fixed Charges	Amount	Volumes	$/Mcf			
9	Take-or-Pay	0	50,500,000	0.0000			
10	Transition	566,305	30,400,000	0.0186			
11	Total	$566,305		0.0186			
12							
13							
14			Volumetric Basis for				
15		Annual	Other Fixed Charges			Other Fixed Charges	
16		Expected Mcf	Take-or-Pay	Transition		Take-or-Pay	Transition
17	Firm Service						
18	Sales:						
19	G-1	24,200,000	24,200,000	24,200,000			0.0186
20	HLF	300,000	300,000	300,000			0.0186
21	LVS-1	1,500,000	1,500,000	1,500,000			0.0186
22	Total Firm Sales	26,000,000	26,000,000	26,000,000			
23							
24	Transportation:						
25	T-2 \ G-1	500,000	500,000	500,000			0.0186
26	T-2 \ G-1 \ HLF	0					0.0186
27	Total Firm Service	26,500,000	26,500,000	26,500,000			
28							
29	Interruptible Service						
30	Sales:						
31	G-2	2,000,000	2,000,000	2,000,000			0.0186
32	LVS-2	1,200,000	1,200,000	1,200,000			0.0186
33	Total Sales	3,200,000	3,200,000	3,200,000			
34							
35	Transportation:						
36	T-2 \ G-2	700,000	700,000	700,000			0.0186
37							
38	Total Interruptible Service	3,900,000	3,900,000	3,900,000			
39							
40	Carriage Service						
41	T-3 & T-4	20,100,000	20,100,000	NA			
42							
43	Total	50,500,000	50,500,000	30,400,000			
44							
45							
46	Note: LVS Credit =	($50,220)					
47							

Western Kentucky Gas Company

Exhibit B

Expected Gas Cost - Commodity

Total System

Line No.	Description	(1) Purchases Mcf	(2) Purchases MMbtu	(3) Rate $/MMbtu	(4) Total $
1	Texas Gas Area				
2	No Notice Service	1,785,574	1,830,213	1.8456	3,377,841
3	Firm Transportation	252,195	258,500	1.8331	473,856
4	No Notice Storage	(152,195)	(156,000)	1.8456	(287,913)
5	Total Texas Gas Area	1,885,574	1,932,713	1.8439	3,563,784
6					
7	Tennessee Gas Area				
8	FT-A and FT-G	298,200	310,128	1.9403	601,742
9	FT-GS	73,825	76,778	2.5333	194,502
10	Gas Storage				
11	FT-A and FT-G Injections	(96,875)	(100,750)	1.9118	(192,614)
12	FT-GS Withdrawals	(28,125)	(29,250)	2.5138	(73,528)
13		247,025	256,906	2.0634	530,102
14	Trunkline Gas Area				
15	Firm Transportation	72,464	75,000	1.8067	135,504
16					
17					
18	WKG System Storage				
19	Injections	(282,927)	(290,000)	1.8331	(531,599)
20	Withdrawals	0	0	2.3000	0
21	Net WKG Storage	(282,927)	(290,000)	1.8331	(531,599)
22					
23					
24	Local Production	20,488	21,000	1.8331	38,495
25					
26					
27					
28	Total Commodity Purchases	1,942,624	1,995,619	1.8722	3,736,286
29					
30	Lost & Unaccounted for @ 1.9%	36,910	37,917		
31					
32	Total Deliveries	1,905,714	1,957,702	1.9085	3,736,286
33					
34	LVS Commodity Credit to System				
35	LVS Sales	(50,000)	(51,364)	1.9118	(98,198)
36					
37					
38	Total Expected Commodity Cost	1,855,714	1,906,338	1.9084	3,638,088
39					
40	Expected Commodity Cost ($/Mcf)			1.9605	
41					
42					
43					

Western Kentucky Gas Company
Load Factor Calculation for Demand Allocation

Line No.	Description	MCF	
	Annualized Volumes Subject to Demand Charges		
1	Sales Volume	26,500,000	
2	Large Volume Sales (Annualized)	2,700,000	
3	Transportation	1,200,000	
4	Total Mcf Billed Demand Charges	30,400,000	
5	Divided by: Days/Year	365	
7	Average Daily Sales and Transport Volumes	83,288	
8			
10	Peak Dav Sales and Transportation Volume		
11	Estimated total company firm requirements for 5 degree average		
12	temperature day from Peak Day Book - with adjustments per rate filing	283,011	Mcf/Peak Day
13			
14			
15	New Load Factor (line 7 / line 12)	0.2943	

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

	Base Tariff Rates (1)	Sec. 33.3 Surcharge (2)	2-1-98 Misc. Revenue Credit Adj. (3)	GRI (1) (4)	FERC ACA (5)	Currently Effective Rates (6)
Zone SL						
Daily Demand	0.0833		(0.0001)	0.0085		0.0917
Commodity	0.0028			0.0088	0.0022	0.0138
Overrun	0.0861	0.0175	(0.0001)	0.0088	0.0022	0.1145
Zone 1						
Daily Demand	0.2844		(0.0001)	0.0085		0.2928
Commodity	0.0184			0.0088	0.0022	0.0294
Overrun	0.3028	0.0175	(0.0001)	0.0088	0.0022	0.3312
Zone 2						
Daily Demand	0.3158		(0.0001)	0.0085		0.3242
Commodity	0.0235			0.0088	0.0022	0.0345
Overrun	0.3393	0.0175	(0.0001)	0.0088	0.0022	0.3677
Zone 3						
Daily Demand	0.3498		(0.0001)	0.0085		0.3582
Commodity	0.0282			0.0088	0.0022	0.0392
Overrun	0.3780	0.0175	(0.0001)	0.0088	0.0022	0.4064
Zone 4						
Daily Demand	0.4096		(0.0001)	0.0085		0.4180
Commodity	0.0333			0.0088	0.0022	0.0443
Overrun	0.4429	0.0175	(0.0001)	0.0088	0.0022	0.4713

Minimum Rate: Demand $-0-; HHS minimum commodity base rates equal applicable HHS maximum commodity base rates.

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

(1) GRI surcharge applicable pursuant to Section 22 of the General Terms and Conditions. The HHS daily demand adjustment for low load factor customers (load factor of 50% or less) is $0.0053.

Exhibit C
Page 1 of 13

Texas Gas Transmission Corporation
FERC Gas Tariff
First Revised Volume No. 1

Superseding

Twenty-fourth Revised Sheet No. 11
Twenty-third Revised Sheet No. 11

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

	Base Tariff Rates (1)	2-1-98 Misc. Revenue Credit Adj. (2)	2-1-98 ISS Revenue Credit Adj. (3)	GRI (1) (4)	Currently Effective Rates (5)
SL-SL	0.0834	(0.0001)	(0.0007)	0.0085	0.0911
SL-1	0.1748	(0.0001)	(0.0007)	0.0085	0.1825
SL-2	0.2122	(0.0001)	(0.0007)	0.0085	0.2199
SL-3	0.2529	(0.0001)	(0.0007)	0.0085	0.2606
SL-4	0.3061	(0.0001)	(0.0007)	0.0085	0.3138
1-1	0.1669	(0.0001)	(0.0007)	0.0085	0.1746
1-2	0.2044	(0.0001)	(0.0007)	0.0085	0.2121
1-3	0.2448	(0.0001)	(0.0007)	0.0085	0.2525
1-4	0.2966	(0.0001)	(0.0007)	0.0085	0.3043
2-2	0.1248	(0.0001)	(0.0007)	0.0085	0.1325
2-3	0.1652	(0.0001)	(0.0007)	0.0085	0.1729
2-4	0.2170	(0.0001)	(0.0007)	0.0085	0.2247
3-3	0.1293	(0.0001)	(0.0007)	0.0085	0.1370
3-4	0.1811	(0.0001)	(0.0007)	0.0085	0.1888
4-4	0.1358	(0.0001)	(0.0007)	0.0085	0.1435

Minimum Rates: Demand $-0-

Backhaul rates equal fronthaul rates to zone of delivery.

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

(1) GRI surcharge applicable pursuant to Section 22 of the General Terms and Conditions. The FT daily demand adjustment for low load factor customers (load factor of 50% or less) is $0.0053.

Issued By: K.R.Cocklin, Vice President, Rates
Issued on: May 29th, 1998

Effective: July 1st, 1998

Texas Gas Transmission Corporation
FERC Gas Tariff
First Revised Volume No. 1

1 Rev Thirteenth Revised Sheet No. 11A
Superseding Thirteenth Revised Sheet No. 11A

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

	Base Tariff Rates (1)	Current TCA Adjustment (2)	Unrecovered TCA Surcharge (3)	GRI(1) (4)	FERC ACA (5)	Currently Effective Rates (6)
SL-SL	0.0132	(0.0072)	0.00000	.0088	0.0018	0.0166
SL-1	0.0218	(0.0072)	0.00000	.0088	0.0018	0.0252
SL-2	0.0260	(0.0072)	0.00000	.0088	0.0018	0.0294
SL-3	0.0307	(0.0072)	0.00000	.0088	0.0018	0.0341
SL-4	0.0335	(0.0072)	0.00000	.0088	0.0018	0.0369
1-1	0.0202	(0.0072)	0.00000	.0088	0.0018	0.0236
1-2	0.0244	(0.0072)	0.00000	.0088	0.0018	0.0278
1-3	0.0290	(0.0072)	0.00000	.0088	0.0018	0.0324
1-4	0.0313	(0.0072)	0.00000	.0088	0.0018	0.0347
2-2	0.0165	(0.0072)	0.00000	.0088	0.0018	0.0199
2-3	0.0211	(0.0072)	0.00000	.0088	0.0018	0.0245
2-4	0.0234	(0.0072)	0.00000	.0088	0.0018	0.0268
3-3	0.0170	(0.0072)	0.00000	.0088	0.0018	0.0204
3-4	0.0193	(0.0072)	0.00000	.0088	0.0018	0.0227
4-4	0.0146	(0.0072)	0.00000	.0088	0.0018	0.0180

Minimum Rates: Commodity minimum rates equal maximum rates, plus the current TCA adjustment.

Backhaul rates equal fronthaul rates to zone of delivery.

(1) GRI surcharge applicable pursuant to Section 22 of the General Terms and Conditions. The FT daily demand adjustment for low load factor customers (load factor of 50% or less) is $0.005).

ssued By: K.R.Cocklin, Vice President, Rates
ssued on: July 31st, 1997

Effective: September 1st, 1997

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

NNS/SGT RATE SCHEDULES

WINTER				SUMMER			
Delivery Zone	Projected Fuel Retention Percentage (PFRP)	Fuel Adjustment Percentage (FAP)	Effective Fuel Retention Percentage (EFRP)	Delivery Zone	Projected Fuel Retention Percentage (PFRP)	Fuel Adjustment Percentage (FAP)	Effective Fuel Retention Percentage (EFRP)
SL	0.49%	(0.21%)	0.28%	SL	0.53%	0.19%	0.72%
1	2.34%	(0.40%)	1.94%	1	2.30%	0.18%	2.48%
2	2.80%	(0.40%)	2.40%	2	2.60%	0.42%	3.02%
3	3.98%	(0.95%)	3.03%	3	2.98%	0.14%	3.12%
4	5.20%	(0.94%)	4.26%	4	3.16%	(0.87%)	2.29%

FT/IT RATE SCHEDULES

WINTER				SUMMER			
Rec/Del Zone	PFRP	FAP	EFRP	Rec/Del Zone	PFRP	FAP	EFRP
SL/SL	0.20%	0.12%	0.32%	SL/SL	0.25%	0.11%	0.36%
SL or 1/1	1.74%	0.31%	2.05%	SL or 1/1	1.77%	0.46%	2.23%
SL or 1/2	2.27%	(0.16%)	2.11%	SL or 1/2	2.41%	0.22%	2.63%
SL or 1/3	3.02%	(0.37%)	2.65%	SL or 1/3	2.85%	(0.07%)	2.78%
SL or 1/4	3.38%	(0.35%)	3.03%	SL or 1/4	3.44%	0.46%	3.90%
2/2	0.38%	0.00%	0.38%	2/2	0.22%	0.00%	0.22%
2/3	0.75%	0.00%	0.75%	2/3	0.44%	0.00%	0.44%
2/4	1.11%	0.00%	1.11%	2/4	1.03%	0.24%	1.27%
3/3	0.38%	0.00%	0.38%	3/3	0.22%	0.00%	0.22%
3/4	0.36%	0.02%	0.38%	3/4	0.59%	0.53%	1.12%
4/4	0.18%	0.01%	0.19%	4/4	0.30%	0.26%	0.56%

FSS/ISS RATE SCHEDULES

Withdrawal			Injection		
PFRP	FAP	EFRP	PFRP	FAP	EFRP
1.12%	0.00%	1.12%	0.53%	0.00%	0.53%

RATES PER DEKATHERM

FIRM TRANSPORTATION - GS RATES (FT-GS)

Base Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.2143		$0.4209	$0.5856	$0.6760	$0.7825	$0.8974	$1.0723
L		$0.1771						
1	$0.4324		$0.3268	$0.4957	$0.5855	$0.6928	$0.8070	$0.9823
2	$0.5856		$0.4957	$0.2006	$0.2903	$0.4151	$0.5112	$0.6870
3	$0.6760		$0.5855	$0.2903	$0.1495	$0.3995	$0.4962	$0.6710
4	$0.8006		$0.7108	$0.4151	$0.3995	$0.1886	$0.2311	$0.4068
5	$0.8974		$0.8070	$0.5112	$0.4957	$0.2311	$0.1989	$0.3473
6	$1.0723		$0.9823	$0.6865	$0.6710	$0.4068	$0.3473	$0.2380

Surcharges

PCB Adjustment: 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0110		$0.0159	$0.0192	$0.0208	$0.0236	$0.0258	$0.0301
L		$0.0069						
1	$0.0159		$0.0137	$0.0170	$0.0192	$0.0219	$0.0241	$0.0279
2	$0.0192		$0.0170	$0.0104	$0.0126	$0.0153	$0.0175	$0.0214
3	$0.0208		$0.0192	$0.0126	$0.0093	$0.0148	$0.0170	$0.0214
4	$0.0236		$0.0219	$0.0153	$0.0148	$0.0104	$0.0110	$0.0153
5	$0.0258		$0.0241	$0.0175	$0.0170	$0.0110	$0.0104	$0.0137
6	$0.0301		$0.0279	$0.0214	$0.0214	$0.0153	$0.0137	$0.0115

Annual Charge Adjustment (ACA): $0.0022
FT-GS Settlement Surcharge: 5/ $0.0893

Maximum Rates 2/, 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.3168		$0.5283	$0.6953	$0.7883	$0.8976	$1.0147	$1.1939
L		$0.2755						
1	$0.5398		$0.4320	$0.6042	$0.6962	$0.8062	$0.9226	$1.1017
2	$0.6953		$0.6042	$0.3025	$0.3944	$0.5219	$0.6202	$0.7999
3	$0.7883		$0.6962	$0.3944	$0.2503	$0.5058	$0.6047	$0.7839
4	$0.9157		$0.8242	$0.5219	$0.5058	$0.2905	$0.3336	$0.5136
5	$1.0147		$0.9226	$0.6202	$0.6042	$0.3336	$0.3008	$0.4525
6	$1.1939		$1.1017	$0.7994	$0.7839	$0.5136	$0.4525	$0.3410

Minimum Rates

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

Notes:

1/ PCB adjustment surcharge is effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, subject to extension, revision or termination as required by the Stipulation & Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

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

3/ Gas Research Institute Charge (GRI) of $0.0200 and Transition Cost Surcharge - Supply Area (TCSS) of $0.0225 are not included in the above stated maximum rates.

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

5/ FT-GS Settlement Surcharge is from January 1, 1997 - December 31, 1998, as set forth in the Stipulation & Agreement filed on February 28, 1997 and approved by Commission Order issued April 16, 1997.

TM 98-1-9 ACCEPTED SEP 29 '97

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base Commodity Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0851	$0.0979	$0.1119	$0.1232	$0.1610
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1015	$0.1127	$0.1505
2	$0.0851		$0.0776	~~$0.0433~~	$0.0530	$0.0632	~~$0.0723~~	$0.1161
3	$0.0979		$0.0874	$0.0530	$0.0366	$0.0664	~~$0.0765~~	$0.1143
4	$0.1130		$0.1026	$0.0622	$0.0664	$0.0401	$0.0459	$0.0835
5	$0.1232		$0.1127	$0.0723	~~$0.0755~~	$0.0459	$0.0427	$0.0766
6	$0.1610		$0.1505	$0.1161	$0.1143	$0.0835	$0.0766	$0.0643

Minimum
Commodity Rates 3/

DELIVERY ZONE

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

Maximum
Commodity Rates 1/, 2/, 3/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0549		$0.0779	$0.0991	$0.1089	$0.1229	$0.1342	$0.1720
L		$0.0396						
1	$0.0779		$0.0682	$0.0886	$0.0984	$0.1125	$0.1237	$0.1615
2	$0.0991		$0.0886	$0.0543	$0.0640	$0.0792	$0.0893	$0.1271
3	$0.1089		$0.0984	$0.0640	$0.0476	$0.0774	$0.0875	$0.1253
4	$0.1240		$0.1136	$0.0792	$0.0774	$0.0511	$0.0569	$0.0945
5	$0.1342		$0.1237	$0.0893	$0.0875	$0.0569	$0.0537	$0.0876
6	$0.1720		$0.1615	$0.1271	$0.1253	$0.0945	$0.0876	$0.0753

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0022
(GRI) Gas Research Institute charge $0.0088
GRI will not be assessed if it is currently being paid on another pipeline.

2/ The TCSS Surcharge is only applicable to deliveries in the supply area as defined on Sheet No. 390. This surcharge is not included in the Maximum Rates Matrix.
(TCSS) Transition Cost Surcharge - Supply Area $0.0225

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

RP 93-151 ACCEPTED APR 30 '97

TENNESSEE GAS PIPELINE COMPANY
FERC Gas Tariff
FIFTH REVISED VOLUME NO. 1

Exhibit C
Page 7 of 13

Sub Eighth Revised Sheet No. 238
Superseding
Eighth Revised Sheet No. 238

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-G

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$3.11		$6.46	$9.08	$10.55	$12.24	$14.13	$16.63
L		$2.71						
1	$6.67		$4.92	$7.63	$9.09	$10.79	$12.67	$15.18
2	$9.08		$7.63	$2.87	$4.33	$6.33	$7.90	$10.42
3	$10.55		$9.09	$4.33	$2.06	$6.08	$7.66	$10.16
4	$12.55		$11.10	$6.33	$6.08	$2.71	$3.38	$5.90
5	$14.13		$12.67	$7.90	$7.65	$3.38	$2.85	$4.94
6	$16.63		$15.18	$10.41	$10.16	$5.90	$4.94	$3.17

Surcharges

PCB Adjustment: 1\

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.20		$0.29	$0.35	$0.38	$0.43	$0.47	$0.55
L		$0.13						
1	$0.29		$0.25	$0.31	$0.35	$0.40	$0.44	$0.51
2	$0.35		$0.31	$0.19	$0.23	$0.28	$0.32	$0.39
3	$0.38		$0.35	$0.23	$0.17	$0.27	$0.31	$0.39
4	$0.43		$0.40	$0.28	$0.27	$0.19	$0.20	$0.28
5	$0.47		$0.44	$0.32	$0.31	$0.20	$0.19	$0.25
6	$0.55		$0.51	$0.39	$0.39	$0.28	$0.25	$0.21

Firm Settlement Surcharge (Article XXXV): 3\ $1.63

Maximum Reservation Rates 2\

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$4.94		$8.38	$11.06	$12.56	$14.30	$16.23	$18.81
L		$4.47						
1	$8.59		$6.80	$9.57	$11.07	$12.82	$14.74	$17.32
2	$11.06		$9.57	$4.69	$6.19	$8.24	$9.85	$12.44
3	$12.56		$11.07	$6.19	$3.86	$7.98	$9.60	$12.18
4	$14.61		$13.13	$8.24	$7.98	$4.53	$5.21	$7.81
5	$16.23		$14.74	$9.85	$9.59	$5.21	$4.67	$6.82
6	$18.81		$17.32	$12.43	$12.18	$7.81	$6.82	$5.01

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

Notes:

1\ PCB adjustment surcharge is effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, subject to extension, revision or termination as required by the Stipulation & Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

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

3\ The Firm Settlement Surcharge is from January 1, 1997 - December 31, 1998, as set forth in the Stipulation & Agreement filed on February 28, 1997 and approved by Commission Order issued April 16, 1997.

Issued by: E. J. Holm, Agent and Attorney-in-Fact
Issued on: April 22, 1997

Effective: May 1, 1997

TM 98-1-9 ACCEPTED SEP 29 '97

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-G

Base Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0439		$0.0669	$0.0831	$0.0979	$0.1119	$0.1232	$0.1610
L		$0.0286						
1	$0.0669		$0.0572	$0.0776	$0.0874	$0.1015	$0.1127	$0.1505
2	$0.0831		$0.0776	$0.0433	$0.0530	$0.0682	$0.0783	$0.1161
3	$0.0979		$0.0874	$0.0530	$0.0366	$0.0664	$0.0765	$0.1143
4	$0.1130		$0.1026	$0.0682	$0.0664	$0.0401	$0.0459	$0.0835
5	$0.1232		$0.1127	$0.0783	$0.0765	$0.0459	$0.0427	$0.0766
6	$0.1610		$0.1505	$0.1161	$0.1143	$0.0835	$0.0766	$0.0643

Minimum
Commodity Rates 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0026		$0.0096	$0.0161	$0.0191	$0.0233	$0.0268	$0.0326
L		$0.0034						
1	$0.0096		$0.0067	$0.0129	$0.0159	$0.0202	$0.0236	$0.0294
2	$0.0161		$0.0129	$0.0024	$0.0054	$0.0100	$0.0131	$0.0189
3	$0.0191		$0.0159	$0.0054	$0.0004	$0.0095	$0.0126	$0.0184
4	$0.0237		$0.0205	$0.0100	$0.0095	$0.0015	$0.0032	$0.0090
5	$0.0268		$0.0236	$0.0131	$0.0125	$0.0032	$0.0022	$0.0069
6	$0.0326		$0.0294	$0.0189	$0.0184	$0.0090	$0.0069	$0.0031

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0661		$0.0891	$0.1103	$0.1201	$0.1341	$0.1454	$0.1832
L		$0.0508						
1	$0.0891		$0.0794	$0.0998	$0.1096	$0.1237	$0.1349	$0.1727
2	$0.1103		$0.0998	$0.0655	$0.0752	$0.0904	$0.1005	$0.1383
3	$0.1201		$0.1096	$0.0752	$0.0588	$0.0886	$0.0987	$0.1365
4	$0.1352		$0.1248	$0.0904	$0.0856	$0.0623	$0.0681	$0.1057
5	$0.1454		$0.1349	$0.1005	$0.0987	$0.0681	$0.0649	$0.0988
6	$0.1832		$0.1727	$0.1383	$0.1365	$0.1057	$0.0988	$0.0865

Notes:

1/ The above maximum rates include a per Dth charge for:
(ACA) Annual Charge Adjustment $0.0022
(GRI) Gas Research Institute Charge $0.0200
GRI will not be assessed if it is currently being paid on another pipeline.

2/ The TCSS Surcharge is only applicable to deliveries in the supply area as defined on sheet no. 390.
This surcharge is not included in the Maximum Rates Matrix.
(TCSS) Transition Cost Surcharge - Supply Area $0.0225

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

Issued by: E. J. Holm, Agent and Attorney-in-Fact
Issued on: September 5, 1997

Effective: October 1, 1997

TM 98-1-9 ACCEPTED SEP 29 '97

RATES PER DEKATHERM

STORAGE SERVICE

Rate Schedule and Rate	Tariff Rate	ADJUSTMENTS (GRI) 2/	(ACA)	(TCSM)	(PCB) 3/	Current Adjustment	Retention Percent 1/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA							
Deliverability Rate	$2.02				$0.00	$2.02	
Space Rate	$0.0248				$0.0000	$0.0248	
Injection Rate	$0.0053					$0.0053	1.49%
Withdrawal Rate	$0.0053					$0.0053	
Overrun Rate	$0.2427					$0.2427	
FIRM STORAGE SERVICE (FS) - MARKET AREA							
Deliverability Rate	$1.15				$0.02	$1.17	
Space Rate	$0.0185				$0.0002	$0.0187	
Injection Rate	$0.0102					$0.0102	1.49%
Withdrawal Rate	$0.0102					$0.0102	
Overrun Rate	$0.1380					$0.1380	
INTERRUPTIBLE STORAGE SERVICE (IS) - MARKET AREA							
Space Rate	$0.0848				$0.0009	$0.0857	
Injection Rate	$0.0102					$0.0102	1.49%
Withdrawal Rate	$0.0102					$0.0102	
INTERRUPTIBLE STORAGE SERVICE (IS) - PRODUCTION AREA							
Space Rate	$0.0993				$0.0000	$0.0993	
Injection Rate	$0.0053					$0.0053	1.49%
Withdrawal Rate	$0.0053					$0.0053	
SS - Storage Service							
SS-E							
Deliverability	$4.20				$0.05	$4.25	
Space Rate	$0.0132				$0.0005	$0.0137	
Injection Rate	$0.0102					$0.0102	2.41%
Withdrawal Rate	$0.0561					$0.0561	
Excess Withdrawal Rate	$0.7800		$0.0022			$0.7822	
SS-NE							
Deliverability	$6.72				$0.06	$6.78	
Space Rate	$0.0132				$0.0007	$0.0139	
Injection Rate	$0.0102					$0.0102	3.25%
Withdrawal Rate	$0.0937					$0.0937	
Excess Withdrawal Rate	$1.1600		$0.0022			$1.1622	

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

2/ The Rates After Current Adjustment for services for Consolidated Gas Supply Corp., Columbia Gas Transmission Corp., East Tennessee Natural Gas Co., Midwestern Gas Transmission Co., National Fuel Gas Supply Corp., Texas Gas Transmission Corp., and Equitrans, Inc. are exclusive of adjustments under Tennessee's FERC Gas Tariff.

3/ PCB adjustment surcharge is effective for PCB Adjustment Period of July 1, 1995 - June 30, 2000, subject to extension, revision or termination as required by the Stipulation & Agreement filed on May 15, 1995 and approved by Commission Orders issued November 29, 1995 and February 20, 1996.

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

NOVEMBER - MARCH

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

APRIL - OCTOBER

RECEIPT ZONE	Delivery Zone 0	L	1	2	3	4	5	6
0	0.84%		2.44%	4.43%	5.04%	5.80%	6.72%	7.42%
L		0.95%						
1	1.56%		1.70%	3.69%	4.29%	5.06%	5.97%	6.67%
2	3.95%		1.85%	1.30%	1.90%	2.66%	3.58%	4.28%
3	5.19%		3.12%	1.13%	0.67%	2.32%	3.19%	3.90%
4	6.34%		4.28%	2.35%	2.67%	1.01%	1.21%	1.92%
5	6.41%		4.34%	2.41%	2.74%	1.07%	1.17%	1.86%
6	7.61%		5.53%	3.61%	3.93%	2.20%	1.27%	0.85%

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

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

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

TRUNKLINE GAS COMPANY
FERC GAS TARIFF
First Revised Volume No. 1

Nineteenth Revised Sheet No. 6
Superseding Eighteenth Revised Sheet No. 6

CURRENTLY EFFECTIVE RATES

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

	Base Rate Per Dt	Adjustments			Maximum Rate Per Dt	Minimum Rate Per Dt	Fuel Reimbursement
		Sec. 23	Sec. 24	Sec. 25			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
RATE SCHEDULE FT							
Field Zone to Zone 2							
- Reservation Rate (1)	$13.9256	-	-	-	$13.9256	-	-
- Usage Rate (2)(3)	0.0170	-	-	$ 0.0131	0.0301	$ 0.0170	3.33 % (4)
- Overrun Rate (5)	0.4579	-	-	-	0.4579	-	-
Zone 1A to Zone 2							
- Reservation Rate (1)	$ 8.9984	-	-	-	$ 8.9984	-	-
- Usage Rate (2)(3)	0.0133	-	-	$ 0.0131	0.0264	$ 0.0133	2.69 %
- Overrun Rate (5)	0.2959	-	-	-	0.2959	-	-
Zone 1B to Zone 2							
- Reservation Rate (1)	$ 6.8341	-	-	-	$ 6.8341	-	-
- Usage Rate (2)(3)	0.0074	-	-	$ 0.0131	0.0205	$ 0.0074	1.58 %
- Overrun Rate (5)	0.2247	-	-	-	0.2247	-	-
Zone 2 Only							
- Reservation Rate (1)	$ 5.1379	-	-	-	$ 5.1379	-	-
- Usage Rate (2)(3)	0.0018	-	-	$ 0.0131	0.0149	$ 0.0018	0.92 %
- Overrun Rate (5)	0.1689	-	-	-	0.1689	-	-
Field Zone to Zone 1B							
- Reservation Rate (1)	$12.1282	-	-	-	$12.1282	-	-
- Usage Rate (2)(3)	0.0152	-	-	$ 0.0131	0.0283	$ 0.0152	2.93 %
- Overrun Rate (5)	0.3988	-	-	-	0.3988	-	-
Zone 1A to Zone 1B							
- Reservation Rate (1)	$ 7.2010	-	-	-	$ 7.2010	-	-
- Usage Rate (2)(3)	0.0115	-	-	$ 0.0131	0.0246	$ 0.0115	2.29 %
- Overrun Rate (5)	0.2368	-	-	-	0.2368	-	-
Zone 1B Only							
- Reservation Rate (1)	$ 5.0367	-	-	-	$ 5.0367	-	-
- Usage Rate (2)(3)	0.0056	-	-	$ 0.0131	0.0187	$ 0.0056	1.18 %
- Overrun Rate (5)	0.1656	-	-	-	0.1656	-	-
Field Zone to Zone 1A							
- Reservation Rate (1)	$10.4320	-	-	-	$10.4320	-	-
- Usage Rate (2)(3)	0.0096	-	-	$ 0.0131	0.0227	$ 0.0096	2.27 %
- Overrun Rate (5)	0.3430	-	-	-	0.3430	-	-
Zone 1A Only							
- Reservation Rate (1)	$ 5.5048	-	-	-	$ 5.5048	-	-
- Usage Rate (2)(3)	0.0059	-	-	$ 0.0131	0.0190	$ 0.0059	1.63 %
- Overrun Rate (5)	0.1810	-	-	-	0.1810	-	-
Field Zone Only							
- Reservation Rate (1)	$ 6.0540	-	-	-	$ 6.0540	-	-
- Usage Rate (2)(3)	0.0037	-	-	$ 0.0068	0.0105	$ 0.0037	1.16 %
- Overrun Rate (5)	0.1990	-	-	-	0.1990	-	-
Gathering Charge (All Zones)							
- Reservation Rate	$ 0.4123				$ 0.4123		
- Overrun Rate (5)	0.0136				0.0136		

(1) Excludes Section 20 GRI Reservation Surcharge: $0.26 High Load Factor (greater than 50%);
$0.16 Low Load Factor (less than or equal to 50%)
(2) Excludes Section 20 GRI Usage Surcharge: $0.0088
(3) Excludes Section 21 Annual Charge Adjustment: $0.0019
(4) Fuel reimbursement for backhauls from Zone 2 to Field Zone is 0.29%
(5) Maximum firm volumetric rate applicable for capacity release

Issued by: William W. Grygar
Vice President
Issued on: January 30, 1997

Effective: April 1, 1997

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP97-6-000, issued November 15, 1996, 77 FERC ¶ 61,175 (1996).

Western Kentucky Gas Company
Basis for Indexed Gas Cost
For the Month of April, 1999
Case No. 95-010 QQ

The projected April, 1999 commodity price was provided by the Gas Supply Department and was based upon the following:

A. The Gas Supply Department reviewed the NYMEX futures close prices for April, 1999 for the period February 17, 1999 through February 25, 1999 which are listed below:

		Apr-99 ($/MMBTU)
Wednesday	17-Feb	$1.800
Thursday	18-Feb	1.767
Friday	19-Feb	1.765
Monday	22-Feb	1.702
Tuesday	23-Feb	1.707
Wednesday	24-Feb	1.697
Thursday	25-Feb	1.659
		$1.728

B. Gas Supply believes prices will remain stable and April prices will settle at $1.75 per Mmbtu for the period that the GCA is to be effective.

Western Kentucky Gas Company
Current "Cash-out" Prices
For the Month of January, 1999

For WKG customers served in:			Indexed [1] Cash-out Price		Transport Charge [2,3]		WKG Cash-out Price
A.	Texas Gas:						
	Zone 2 Area	100% of Index Price	$1.8550	+	$0.0345	=	$1.8895
		90% of Index Price	1.6695	+	0.0345	=	1.7040
		80% of Index Price	1.4840	+	0.0345	=	1.5185
	Zone 3 Area	100% of Index Price	$1.8550	+	$0.0392	=	$1.8942
		90% of Index Price	1.6695	+	0.0392	=	1.7087
		80% of Index Price	1.4840	+	0.0392	=	1.5232
	Zone 4 Area	100% of Index Price	$1.8550	+	$0.0443	=	$1.8993
		90% of Index Price	1.6695	+	0.0443	=	1.7138
		80% of Index Price	1.4840	+	0.0443	=	1.5283
B.	Tennessee Gas:						
	Zone 2 Area	100% of Index Price	$1.8352	+	$0.0271	=	$1.8623
		90% of Index Price	1.6517	+	0.0271	=	1.6788
		80% of Index Price	1.4682	+	0.0271	=	1.4953

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

[2] Transport charge used for Texas Gas is its tariff sheet no. 10 commodity rate.

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

Western Kentucky Gas Company
Correction Factor (CF)
For the Six Months Ended December 31,1998
Case No. 95-010 QQ

(1) Month	(2) Actual Sales Volume (Mcf)	(3) Recoverable Gas Cost	(4) Actual Recovered Gas Cost	(5) Under (Over) Recovery Amount	(6) Adjustments	(7) Total
July	690,598	3,465,145.17	2,091,812.46	1,373,332.71	0.00	1,373,332.71
August	559,128	3,650,649.85	2,125,095.01	1,525,554.84	0.00	1,525,554.84
September	563,824	2,109,673.07	1,964,387.78	145,285.29	0.00	145,285.29
October	861,480	3,016,318.49	2,544,204.53	472,113.96	0.00	472,113.96
November	1,383,331	4,299,431.18	5,311,693.12	(1,012,261.94)	0.00	(1,012,261.94)
December	3,351,713	6,665,111.19	7,505,652.78	(840,541.59)	0.00	(840,541.59)
Total Gas Cost Under/(Over) Recovery		23,206,328.95	21,542,845.68	1,663,483.27	0.00	1,663,483.27

Account 191 Balance @ June 30, 1998	($8,242,233.94)
Total Gas Cost Under/(Over) Recovery for the six months ended December 31,1998	1,663,483.27
Recovery from outstanding Correction Factor (CF)	1,591,900.06
Account 191 Balance @ December 31,1998	(4,986,850.61)

Derivation of Correction Factor (CF):

Account 191 Balance	($4,986,851)	
Divided By: Total Expected Customer Sales	26,500,000	MCF
Correction Factor (CF)	**($0.1882)**	**/MCF**

Western Kentucky Gas Company
Recoverable Gas Cost Calculation
For the Six Months Ended December 31, 1998
Case No. 95-010 QQ

Line No.	Description	Unit	(1) July	(2) August	(3) September	(4) October	(5) November	(6) December	Source Document
			Month						
1	**Supply Volume**								
2	Pipelines:								
3	Texas Gas Transmission [1]	Mcf	0	0	0	0	0	0	
4	Tennessee Gas Pipeline [1]	Mcf	0	0	0	0	0	0	
5	Trunkline Gas Company [1]	Mcf	0	0	0	0	0	0	
6	ANR Pipeline [1]	Mcf	0	0	0	0	0	0	
7	**Total Pipeline Supply**	Mcf	0	0	0	0	0	0	
8	Total Other Suppliers	Mcf	2,007,095	1,826,502	1,386,810	1,916,871	904,016	1,222,098	pages 5 & 6
9	Off System Storage								
10	Texas Gas Transmission	Mcf	(713,151)	(635,542)	(334,212)	(286,222)	395,710	967,119	
11	Tennessee Gas Pipeline	Mcf	(246,713)	(143,005)	(115,906)	(92,820)	126,722	310,577	
12	System Storage								
13	Withdrawals	Mcf	0	0	0	0	406,305	995,259	
14	Injections	Mcf	(691,561)	(619,952)	(441,421)	(148,514)	0	0	
15	Producers	Mcf	23,687	22,604	21,462	20,662	19,491	19,216	
16	Pipeline Imbalances cashed out	Mcf	0	0	0	0	0	0	
17	System Imbalances [2]	Mcf	275,428	143,313	110,294	(336,427)	(20,582)	(160,628)	
18	**Total Supply**	Mcf	654,785	593,920	627,027	1,073,550	1,831,662	3,353,641	
19									
20	Change in Unbilled	Mcf	36,423	(34,237)	(62,566)	(211,403)	(447,199)	(873,858)	
21	Company Use	Mcf	(610)	(555)	(637)	(667)	(1,132)	(1,928)	
22	Unaccounted For	Mcf	0	0	0	0	0	0	
23	**Total Sales**	Mcf	690,598	559,128	563,824	861,480	1,383,331	2,477,855	

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

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

Western Kentucky Gas Company
Recoverable Gas Cost Calculation
For the Six Months Ended December 31,1998
Case No. 95-010 QQ

Line No.	Description	Unit	(1) July	(2) August	(3) September	(4) October	(5) November	(6) December	Source Document
			Month						
1	**Supply Cost**								
2	Pipelines:								
3	Texas Gas Transmission [1]	$	1,223,184	1,225,359	1,181,780	1,206,924	1,588,631	1,873,232	
4	Tennessee Gas Pipeline [1]	$	227,666	230,405	235,982	318,099	449,184	264,401	
5	Trunkline Gas Company [1]	$	19,527	19,495	18,619	68,096	69,369	81,660	
6	ANR Pipeline [1]	$	0	0	0	0	0	0	
7	**Total Pipeline Supply**	$	1,470,378	1,475,259	1,436,381	1,593,119	2,107,184	2,219,293	
8	Total Other Suppliers	$	4,663,897	5,090,392	2,651,912	3,544,117	1,783,268	3,459,187	page 5 & 6
9	Off System Storage								
10	Texas Gas Transmission	$	(1,207,286)	(1,377,307)	(732,522)	(627,020)	857,976	2,104,227	
11	Tennessee Gas Pipeline	$	(615,585)	(316,847)	(228,289)	(202,826)	281,220	688,860	
12	System Storage								
13	Withdrawals	$	0	0	0	0	921,343	2,256,867	
14	Injections	$	(1,636,386)	(1,214,063)	(915,743)	(296,703)	0	0	
15	Producers	$	56,808	44,423	35,311	43,212	39,452	37,225	
16	Pipeline Imbalances cashed out	$	0	0	0	0	0	0	
17	System Imbalances [2]	$	609,758	68,761	80,384	(306,572)	(145,156)	(1,081,028)	
18	**Sub-Total**	$	3,341,583	3,770,618	2,327,434	3,747,328	5,845,286	9,684,631	
19									
20	Change in Unbilled	$	125,612	(118,073)	(215,771)	(729,066)	(1,542,255)	(3,013,674)	
21	Company Use	$	(2,050)	(1,895)	(1,990)	(1,943)	(3,600)	(5,846)	
22	Recovered thru Transportation	$	0	0	0	0	0	0	
23	**Total Recoverable Gas Cost**	$	3,465,145	3,650,650	2,109,673	3,016,318	4,299,431	6,665,111	

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

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

Western Kentucky Gas Company
Recovery from Correction Factors (CF)
For the Six Months Ended December 31,1998
Case No. 95-010 QQ

Line No.	Month	Type of Sales	Mcf Sold	Rate	Amount
1	July	G-1 Sales	457,492.3	$0.1147	$52,474.37
2		HLF Sales	21,273.0	0.1147	2,440.01
3		G-2 Sales	87,333.7	0.1147	10,017.18
4		T-3 Overrun Sales	13,279.0	0.1262	1,675.81
5		T-4 Overrun Sales	7,198.0	0.1262	908.39
6		LVS-1 Sales	1,187.0	0.0000	0.00
7		LVS-2 Sales	24,588.0	0.0000	0.00
8		LVS HLF Sales	0.0	0.0000	0.00
9		Total - July	612,351.0		67,515.76
10					
11	August	G-1 Sales	475,509.7	$0.1147	$54,540.97
12		HLF Sales	18,367.0	0.1147	2,106.69
13		G-2 Sales	45,715.1	0.1147	5,243.52
14		T-3 Overrun Sales	3,835.0	0.1262	483.98
15		T-4 Overrun Sales	24,170.0	0.1262	3,050.25
16		LVS-1 Sales	2,497.0	0.0000	0.00
17		LVS-2 Sales	35,863.0	0.0000	0.00
18		LVS HLF Sales	0.0	0.0000	0.00
19		Total - August	605,956.8		65,425.41
20					
21	September	G-1 Sales	473,296.3	$0.1147	$54,287.09
22		HLF Sales	17,418.0	0.1147	1,997.84
23		G-2 Sales	87,744.1	0.1147	10,064.25
24		T-3 Overrun Sales	23,656.0	0.1262	2,985.39
25		T-4 Overrun Sales	(20,291.0)	0.1262	(2,560.72)
26		LVS-1 Sales	1,500.0	0.0000	0.00
27		LVS-2 Sales	29,020.0	0.0000	0.00
28		LVS HLF Sales	0.0	0.0000	0.00
29		Total - September	612,343.4		66,773.85
30					
31	October	G-1 Sales	595,248.1	$0.3110	$185,122.16
32		HLF Sales	15,299.0	0.3110	4,757.99
33		G-2 Sales	132,616.4	0.3110	41,243.70
34		T-3 Overrun Sales	13,991.0	0.3421	4,786.32
35		T-4 Overrun Sales	7,929.0	0.3421	2,712.51
36		LVS-1 Sales	1,550.0	0.0000	0.00
37		LVS-2 Sales	41,847.0	0.0000	0.00
38		LVS HLF Sales	0.0	0.0000	0.00
39		Total - October	808,480.5		238,622.68
40					
41	November	G-1 Sales	1,327,300.6	$0.3110	$412,790.49
42		HLF Sales	11,021.0	0.3110	3,427.53
43		G-2 Sales	152,404.3	0.3110	47,397.74
44		T-3 Overrun Sales	1,917.0	0.3421	655.81
45		T-4 Overrun Sales	5,673.0	0.3421	1,940.73
46		LVS-1 Sales	1,500.0	0.0000	0.00
47		LVS-2 Sales	42,806.0	0.0000	0.00
48		LVS HLF Sales	0.0	0.0000	0.00
49		Total - November	1,542,621.9		466,212.30
50					
51	December	G-1 Sales	2,030,919.1	$0.3110	$631,615.84
52		HLF Sales	13,586.0	0.3110	4,225.25
53		G-2 Sales	108,100.3	0.3110	33,619.19
54		T-3 Overrun Sales	26,837.0	0.3421	9,180.94
55		T-4 Overrun Sales	25,457.0	0.3421	8,708.84
56		LVS-1 Sales	1,350.0	0.0000	0.00
57		LVS-2 Sales	31,425.0	0.0000	0.00
58		LVS HLF Sales	0.0	0.0000	0.00
59		Total - December	2,237,674.4		687,350.06
60					
61	Total Recovery from Correction Factor (CF)				$1,591,900.06
62					

63 LVS sales commodity is "trued-up" according to Section 3(f) in LVS tariff in P.S.C. No. 20.

64

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

68

Western Kentucky Gas Company
Detail Sheet for Supply Volumes & Costs
Traditional and Other Pipelines

Description	July, 1998		August, 1998		September, 1998	
	MCF	Cost	MCF	Cost	MCF	Cost
Texas Gas Pipeline Area						
LG&E Natural						
Woodward Marketing						
Texaco Gas Marketing						
CMS						
WESCO						
Southern Energy Company						
Union Pacific Fuels						
Noram Energy						
Engage						
ERI						
Prepaid						
Reservation						
Fuel Adjustment						
Total	1,426,487	$3,342,317.39	1,398,455	$4,110,171.39	1,071,920	$2,097,000.50
Tennessee Gas Pipeline Area						
Noram Energy						
Union Pacific Fuels						
WESCO						
Prepaid						
Reservation						
Fuel Adjustment						
Total	321,307	$746,529.95	212,239	$591,714.98	185,162	$330,176.41
Trunkline Gas Company						
Noram Energy						
Engage						
Prepaid						
Reservation						
Fuel Adjustment						
Total	65,252	$149,020.47	65,371	$121,580.76	43,912	$77,746.87
ANR Pipeline						
Noram Energy						
LG&E Natural						
Anadarko						
Prepaid						
Reservation						
Fuel Adjustment						
Total	194,049	$426,029.30	150,437	$266,925.00	85,816	$146,988.51
All Zones						
Total	2,007,095	$4,663,897.11	1,826,502	$5,090,392.13	1,386,810	$2,651,912.29

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

Western Kentucky Gas Company
Detail Sheet for Supply Volumes & Costs
Traditional and Other Pipelines

	October, 1998		November, 1998		December, 1998	
Description	MCF	Cost	MCF	Cost	MCF	Cost
Texas Gas Pipeline Area						
LG&E Natural						
ERI						
Texaco Gas Marketing						
WESCO						
PG&E						
Southern Energy Company						
Union Pacific Fuels						
Noram						
Proenergy						
Transcanada						
Prepaid						
Reservation						
Fuel Adjustment						
Total	1,325,438	$2,362,417.63	635,441	$1,286,643.55	1,023,524	$3,086,814.76
Tennessee Gas Pipeline Area						
Noram						
LG&E Natural						
WESCO						
Prepaid						
Reservation						
Fuel Adjustment						
Total	239,905	$460,333.76	124,382	$218,084.18	(2,232)	($4,156.63)
Trunkline Gas Company						
Noram						
PG&E						
Engage						
Reservation						
Fuel Adjustment						
Total	89,650	$175,117.59	144,060	$290,520.23	196,027	$367,473.51
ANR Pipeline						
Noram						
LG&E Natural						
Anadarko						
Prepaid						
Reservation						
Fuel Adjustment						
Total	261,878	$546,248.26	133	($11,980.18)	4,779	$9,054.88
All Zones						
Total	1,916,871	$3,544,117.24	904,016	$1,783,267.78	1,222,098	$3,459,186.52

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

Western Kentucky Gas Company
Estimated Refund Factors and Interest Calculation
Case No. 95-010 QQ
(RF)

Line No.	Refunds Reported:	(1) Demand	(2) Commodity	(3) Total	AMOUNT
1	Texas Gas Transmission Refund in FERC Docket No. RP97-344				$ 1,118,977.25
2					
3	Carry-over Amount in Case No. 95-010 CC				7,695.14
4					
5	Total Refunds				$ 1,126,672.39
6					
7	Flow-through of Customer Refunds and Interest:				
8	Total Refunds				$ 1,126,672.39
9	Less: refund related to specific end users				0.00
10	Refund to flow-through				$ 1,126,672.39
11					
12	Average of the 3-Month Commercial Paper Rates for the immediately				4.8183%
13	preceding 12-month period less 1/2 of 1% to cover the costs of refunding.				
14					
15		(1)	(2)	(3)	
16	**Allocation of Refund**	Demand	Commodity	Total	
17		$1,082,954	$36,023	$1,118,977	
18	Carry-over amount previous Cases	0	7,695	7,695	
19					
20	Total (w/o interest)	1,082,954	43,718	1,126,672	
21	Interest (Line 20 x Line 12)	52,180	2,106	54,286	
22	Total	$1,135,134	$45,824	$1,180,959	
23					
24	**Refund Factor Calculation**				
25	Demand Allocator - All				
26	(See Exh. B, p. 9, line 18)	0.2943			
27	Demand Allocator - Firm				
28	(1 - Demand Allocator - All)	0.7057			
29	MCF Sales (annual normalized)				
30	(See Exh. B, p. 9, line 1)	26,500,000			
31	Firm Volumes (normalized)				
32	(See Exh. B, p. 6, col. 1, line 26)	26,500,000			
33	Total Throughput				
34	(See Exh. B, p. 6, col. 1, line 42 - line 40)	30,400,000			
35					
36	Demand Refund - All (Principal)	$ 318,713	$0.0105 / MCF		
37	Demand Refund - All (Interest)	$ 15,357	$0.0005 / MCF		
38	Demand Refund - Firm (Principal)	$ 764,241	$0.0288 / MCF		
39	Demand Refund - Firm (Interest)	$ 36,823	$0.0014 / MCF		
40	Commodity Refund Factor - Principal			$ 0.0016 / MCF	
41	Commodity Refund Factor - Interest			$ 0.0001 / MCF	
42	Total Demand Firm Refund Factor				
43	(Col. 2, line 36 + 37 + 38 + 39)		$0.0412 / MCF		
44	Total Demand Interruptible Refund Factor				
45	(Col. 2, line 36 + 37)		$0.0110 / MCF		
46	Total Firm Sales Refund Factor				
47	(Col. 3, line 40 + line 41 + col. 2, line 43)	$ 0.0429 / MCF			
48	Total Interruptible Sales Refund Factor				
49	(Col. 3, line 40 + line 41 + col. 2, line 45)	$ 0.0127 / MCF			
50					

01/11/99 0109901 LESS PAST DUE AMOUNTS
01/11/99 0139193 RP 97-344 REFUND

RECEIVED
JAN 18 1999
GAS SUPPLY

CHECK NO	VENDOR NO	CHECK DATE	TOTALS		
73211	W001 0	01/12/99		$1,118,977.25	$1,1[illegible]

CHECK NO
73211
VENDOR NO
W001 0

TEXAS GAS TRANSMISSION
ONE OF THE WILLIAMS COMPANIES, INC.
OWENSBORO, KENTUCKY

CHECK DATE
01/12/99

073211

PAY EXACTLY
$1,118,[illegible]

PAY -----1,118,977 DOLLARS AND 25 CENTS-------------------------

WESTERN KENTUCKY GAS COMPANY
ATTN: GAS SUPPLY
P. O. BOX 650205
DALLAS, TX 75265-0205

TEXAS GAS Transmission Corporation

AUTHORIZED SIGNATURE

⑈073211⑈ ⑆011201539⑆ 80 025 389⑈

Williams.

SUSANNE W. HARRIS
Director of Accounting
502/688-6703
502/688-6996 office fax

Gas Pipelines - Texas Gas
P.O. Box 20008
3800 Frederica Street
Owensboro, Kentucky 42304
502/926-8686

January 13, 1999

Ladies and Gentlemen:

Enclosed is a check representing the sum of the refund applicable to gas service rendered to you during November 1, 1997 through November 30, 1998. The refund represents the difference between the base tariff settlement rates approved in Docket No. RP97-344 and the base tariff rates actually invoiced for quantities delivered by Texas Gas during this refund period. Your refund also includes interest computed at the Federal Energy Regulatory Commission's (FERC's) interest rates listed below from the date paid through January 13, 1999 compounded quarterly.

Period	%
Fourth Quarter 1997	8.50
First Quarter 1998	8.50
Second Quarter 1998	8.50
Third Quarter 1998	8.50
Fourth Quarter 1998	8.50
First Quarter 1999	8.17

Also enclosed are schedules showing the computation of your refunds and related interest. The refund schedules were prepared in accordance with Article II of the Stipulation and Agreement in Texas Gas's general rate case Docket No. RP97-344, et al., pursuant to FERC orders issued July 15, 1998 and October 14, 1998. Pursuant to Section 25.6(e) of the General Terms and Conditions of Texas Gas's Tariff, releasing shippers are responsible for any refunds due to replacement shippers.

Sincerely,

Susanne W. Harris

Susanne W. Harris

SWH:kd
Enclosures

m:dever k bobbi refund : .

Williams

GAS PIPELINE
Texas Gas
P.O. Box 20008
3800 Frederica St.
Owensboro, Kentucky 42304
502/926-8686

January 13, 1999

Dear Customer:

A portion of your RP97-344 rate refund has been applied to your past due account as of December 31, 1998. Also enclosed is the Refund Report that Texas Gas will file with the Commission within 30 days. If you have any questions concerning this refund, please call me at (502) 688-6781 or Kristie Hayden (502) 688-6794.

Sincerely,

Bobbi A. Mann

Bobbi A. Mann
Manager, Financial Reporting &
Gas Revenue Accounting

TEXAS GAS TRANSMISSION CORPORATION

Gas Revenue Accounting/P.O. Box 20008/Owensboro, KY 42304/ (502) 688-6789

WESTERN KENTUCKY GAS COMPANY
ATTN: INTERSTATE GAS SUPPLY DEPT.
PO BOX 650205
DALLAS , TX 75265-0205

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344
NOVEMBER 01, 1997 - NOVEMBER 30, 1998

Customer: WESTERN KENTUCKY GAS COMPANY

Contract Number		Principal Refund	Interest Due	Total Refund Due
Firm Transportation				
003355	0000	$137,986.10	$10,308.52	$148,294.62
003819	0000	$17,858.96	$1,457.90	$19,316.86
012471	0000	$3,712.50	$284.07	$3,996.57
013687	0000	$0.00	$0.00	$0.00
Total Firm Transportation		$159,557.56	$12,050.49	$171,608.05
No-Notice Service				
000210	0000	$198,435.90	$16,328.34	$214,764.24
000340	0000	$578,872.93	$45,142.48	$624,015.41
000435	0000	$100,367.12	$8,227.35	$108,594.47
Total No-Notice Service		$877,675.95	$69,698.17	$947,374.12
Total		$1,037,233.51	$81,748.66	$1,118,982.17
Balancing		$0.00	$0.00	$0.00
Grand Total		$1,037,233.51	$81,748.66	$1,118,982.17

			Past Due
Demand	$1,082,954.40		$1,082,954.40
Commodity	36,027.77	<4.92>	36,022.85
	$1,118,982.17		$1,118,977.25

Exhibit E
Page 6 of 26

TEXAS GAS TRANSMISSION CORPORATION
DOCKET NO. RP 97-344
COMPUTATION OF REFUND DUE ON REVENUES COLLECTED SUBJECT TO REFUND DATES
FOR THE PERIOD NOVEMBER 1, 1997 THROUGH NOVEMBER 30, 1998
WITH INTEREST COMPOUNDED QUARTERLY THROUGH JANUARY 13, 1999

	CUSTOMER NAME	PRINCIPAL REFUND	INTEREST DUE	TOTAL REFUND DUE
1	ALLENERGY MARKETING CO LLC	567 13	43 17	610 35
2	ALLIANCE ENERGY SERVICES	4 74	0 46	5 20
3	AMERISTEEL CORPORATION	1,025 75	73.26	1,099 01
4	AMOCO ENERGY TRADING CORP.	64,426 86	5,225.99	69,652.85
5	AQUILA ENERGY MARKETING CORP	70,935 30	6,040 91	76,976 21
6	ARKLA A DIV OF NORAM ENERGY	176,740 57	13,797 59	190,538.16
7	AURORA NATURAL GAS LLC	5 75	0 22	5.97
8	BALTIMORE GAS & ELECTRIC CO	110,609 00	9,030 08	119,639 08
9	BASILE. LA. TOWN OF	945 37	73 00	1,018 37
10	BAY STATE GAS COMPANY	23,699 61	1,919 44	25,619.05
11	BELLS. TN. CITY OF	3,673 81	302.64	3,976.45
12	BENTON. KY. CITY OF	14,501 40	1,229 28	15,730 68
13	BOONVILLE NATURAL GAS CORP	19,961 52	1,589.33	21,550.85
14	BOSTON GAS COMPANY	64,261 46	5,241.32	69,502.78
15	BROOKLYN UNION GAS COMPANY	16,411 80	1,427.49	17,839.29
16	BROWNSVILLE UTILITY BOARD	21,716 12	1,784 96	23,501.08
17	CARGILL INC TN	306 21	14.39	320 60
18	CARROLLTON. KY. CITY OF	31,005 55	2,577.59	33,583.14
19	CATEX CORAL ENERGY LLC	38,951.77	3,365.34	42,317.11
20	CENERPRISE INC	10,365 33	859.75	11,225 08
21	CENTRAL ILLINOIS PUBLIC SVC CO	91,631.24	7,107.98	98,739.22
22	CHANDLER NATURAL GAS CORP	6,069.26	492.71	6,561.97
23	CINCINNATI GAS & ELECTRIC CO	616,921 85	50,140.38	667,062.23
24	CINERGY RESOURCES INC	9,236.96	794.22	10,031.18
25	CLARENDON. AR. TOWN OF	4,022.15	329.55	4,351.70
26	CLAY. KY. CITY OF	3,461.12	311 79	3,772 91
27	CMS ENTERPRISES COMPANY	1,626.60	(79.58)	1,547 02
28	CMS MARKETING SERVICES & TRDG	47,842 41	3 835.84	51,678 25
29	CNG ENERGY SERVICES CORP	91,113 15	7,214 55	98,327 70
30	CNG PRODUCING COMPANY	9,391 40	801.20	10,192 60
31	COAST ENERGY GROUP	3 995 14	237.77	4,232.91
32	COENERGY TRADING COMPANY	1,521 30	89.17	1,610 47
33	COLUMBIA ENERGY SERVICES CORP	17,253 27	1,069 41	18,322.68
34	COLVIN GAS COMPANY	46 81	3 86	50 67
35	COM/ENERGY MARKETING INC	59 77	3 74	63.51
36	COMMONWEALTH ALUMINUM CORP.	45,133 84	3,648.29	48,782 13
37	COMMONWEALTH GAS COMPANY	1,374.02	72.21	1,446.23
38	COMMUNITY NATURAL GAS CO INC	17,235 48	1,469.95	18,705 43
39	CONOCO. INC.	6,799.72	526.14	7,325.86
40	CORAL ENERGY RESOURCES L.P.	4,155.05	324.38	4,479.43
41	CORNING NATURAL GAS CORP.	784.93	41.66	826.59
42	COVINGTON. TN. CITY OF	18,571.95	1 515 56	20,087 51
43	CROCKETT PUBLIC UTILITY DIST.	4 800 66	408.38	5,209 04
44	DAYTON POWER & LIGHT COMPANY	155,797 78	13,422 78	169,220.56
45	DOME GAS COMPANY INC.	17,267.17	1,457 01	18,724 18
46	DOW CORNING CORPORATION	17,491 84	1,415 06	18,906.90
47	DRAKESBORO. KY CITY OF	3 463 70	290.31	3,754 01
48	DUCK HILL. MS. TOWN OF	2,298.90	174.17	2,473 07
49	DUKE ENERGY TRADING & MKTG LLC	6,150 94	474.93	6,625 87
50	DYERSBURG. TN. CITY OF	68,054 89	5,689.70	73,744 59
51	EAST OHIO GAS COMPANY	390,720 86	31,672 96	422,393 82
52	EASTERN ENERGY MARKETING INC	34.14	3.14	37 28
53	EL PASO ENERGY MARKETING CO.	125,464 46	10,419 53	135,883 99

TEXAS GAS TRANSMISSION CORPORATION
DOCKET NO. RP 97-344
COMPUTATION OF REFUND DUE ON REVENUES COLLECTED SUBJECT TO REFUND DATES
FOR THE PERIOD NOVEMBER 1, 1997 THROUGH NOVEMBER 30, 1998
WITH INTEREST COMPOUNDED QUARTERLY THROUGH JANUARY 13, 1999

CUSTOMER NAME	PRINCIPAL REFUND	INTEREST DUE	TOTAL REFUND DUE
54 ELIZABETH NATURAL GAS, INC	66.38	4.70	71.08
55 ELIZABETHTOWN GAS COMPANY	92,909.62	7,519.25	100,428.87
56 ELIZABETHTOWN, KY, CITY OF	72,852.21	5,962.39	78,814.60
57 ENERGAS CORPORATION	76.15	6.30	82.45
58 ENERGY MARKETING SERVICES INC	4,825.60	410.91	5,236.51
59 ENERGYEXPRESS INC	117.17	8.40	125.57
60 ENERGYVISION LLC	914.14	71.88	986.02
61 ENGAGE ENERGY US LP	23,477.24	1,996.25	25,473.49
62 ENRON ADMINISTRATIVE SVC CORP	4,091.81	216.54	4,308.35
63 ENRON CAPITAL&TRADE RESOURCES	7,446.80	476.76	7,923.56
64 ENSERCH ENERGY SERVICES INC.	1,152.54	91.96	1,244.50
65 ENTEX A DIV OF NORAM ENERGY	348.04	25.86	373.90
66 EPEC MARKETING COMPANY	1,064.61	95.32	1,159.93
67 ERI SERVICES INC	66.44	5.79	72.23
68 EVANGELINE GAS COMPANY INC	6,321.49	462.81	6,784.30
69 FARMERS GAS SERVICE, INC.	57.48	5.16	62.64
70 FARMLAND INDUSTRIES INC	8,165.04	584.79	8,749.83
71 FIRST UTILITY DIST. OF TIPTON	5,989.10	506.40	6,495.50
72 FLAT ROCK, ILLINOIS, VILLAGE	1,337.14	112.33	1,449.47
73 FORD MOTOR COMPANY	9,500.82	717.11	10,217.93
74 FRIARS POINT, MS, TOWN OF	2,138.20	177.29	2,315.49
75 FRIENDSHIP, TN, CITY OF	853.54	74.15	927.69
76 FULTON, KY, CITY OF	5,840.26	491.92	6,332.18
77 GALLATIN STEEL COMPANY	9,090.20	789.06	9,879.26
78 GALLAWAY, TN, CITY OF	821.62	65.61	887.23
79 GAS UTLTY DIST #3 GRANT PARISH	708.15	58.21	766.36
80 GIBBS DIE CASTING CORPORATION	13,728.64	1,028.74	14,757.38
81 GIBSON COUNTY UTILITY DISTRICT	49,277.08	4,114.10	53,391.18
82 H & N GAS LTD	895.73	62.21	957.94
83 HALLS, TN, TOWN OF	5,083.35	417.05	5,500.40
84 HAMILTON, OH, CITY OF	96,775.00	7,898.27	104,673.27
85 HARDIN, KY, CITY OF	2,139.84	178.85	2,318.69
86 HEATH PETRA RESOURCES INC.	1,548.78	123.95	1,672.73
87 HENDERSON, KY, CITY OF	124,320.53	9,920.65	134,241.18
88 HENNING, TN, TOWN OF	1,378.73	114.44	1,493.17
89 HIGHLAND ENERGY COMPANY	185.82	15.39	201.21
90 HOLLY GROVE, AR, CITY OF	1,507.75	126.41	1,634.16
91 HOPE GAS INC	24,791.41	1,782.02	26,573.43
92 HUMBOLDT UTILITIES	16,945.94	1,431.68	18,377.62
93 ILLINOIS GAS COMPANY	112,221.04	8,997.37	121,218.41
94 INDIANA GAS COMPANY INC	194,534.55	16,827.27	211,361.82
95 INDIANA NATURAL GAS CORP.	30,528.42	2,490.46	33,018.88
96 INDIANA UTILITIES CORPORATION	13,437.83	1,145.85	14,583.68
97 INNOVATIVE GAS SERVICES INC	296,675.59	25,494.21	322,169.80
98 INTERSTATE GAS SUPPLY, INC.	329.16	28.46	357.62
99 JACKSON UTILITY DIVISION	217,919.37	17,276.07	235,195.44
100 JASONVILLE, IN, CITY OF	6,350.06	537.60	6,887.66
101 JENA, LA, TOWN OF	3,448.22	273.12	3,721.34
102 JENNINGS GAS, INC.	54.61	3.17	57.78
103 JONES GAS COMPANY	123.39	11.28	134.67
104 KUTTAWA, KY, CITY OF	2,564.94	217.30	2,782.24
105 LAWRENCEBURG GAS COMPANY	37,340.12	3,135.39	40,475.51
106 LEITCHFIELD, KY, CITY OF	15,520.75	1,274.60	16,795.35

TEXAS GAS TRANSMISSION CORPORATION
DOCKET NO. RP 97-344
COMPUTATION OF REFUND DUE ON REVENUES COLLECTED SUBJECT TO REFUND DATES
FOR THE PERIOD NOVEMBER 1, 1997 THROUGH NOVEMBER 30, 1998
WITH INTEREST COMPOUNDED QUARTERLY THROUGH JANUARY 13, 1999

CUSTOMER NAME	PRINCIPAL REFUND	INTEREST DUE	TOTAL REFUND DUE
107 LEWISPORT, KY, CITY OF	5,755.62	485.81	6,241.43
108 LEXINGTON, NC, CITY OF	10,886.75	893.96	11,780.71
109 LG&E NATURAL MARKETING INC.	31.65	2.46	34.11
110 LINTON, IN, CITY OF	16,419.47	1,370.43	17,789.90
111 LIVERMORE, KY, CITY OF	2,935.18	243.59	3,178.77
112 LOGAN ALUMINUM INC	52,406.54	3,923.56	56,330.10
113 LOUIS DREYFUS ENERGY CORP.	49.13	4.05	53.18
114 LOUISIANA GAS SERVICE COMPANY	2,497.36	200.78	2,698.14
115 LOUISVILLE GAS & ELECTRIC CO	1,302,679.84	106,245.78	1,408,925.62
116 MAMOU, LA, TOWN OF	2,964.09	211.98	3,176.07
117 MARATHON OIL COMPANY	117,076.36	8,781.04	125,857.40
118 MARCON ENERGY CORPORATION	385,909.30	30,961.97	416,871.27
119 MARTIN, TN, CITY OF	15,095.02	1,302.86	16,397.88
120 MARVELL, AR, CITY OF	6,182.46	513.24	6,695.70
121 MAURY CITY, TN, TOWN OF	2,353.56	201.84	2,555.40
122 MEMPHIS LIGHT, GAS & WATER	1,618,128.68	128,699.31	1,746,827.99
123 METCALFE, MS, TOWN OF	859.99	64.76	924.75
124 MIAMI VALLEY RESOURCES, INC.	27,192.40	2,255.14	29,447.54
125 MIDWEST NATURAL GAS CORP.	88,819.13	6,993.81	95,812.94
126 MISSISSIPPI ENERGIES INC	15,348.88	1,212.34	16,561.22
127 MISSISSIPPI VALLEY GAS COMPANY	489,724.35	39,240.37	528,964.72
128 MORGAN CITY, LA, CITY OF	7,770.30	600.49	8,370.79
129 MORGANFIELD, KY, CITY OF	16,852.51	1,439.70	18,292.21
130 MOUNTAIN GAS RESOURCES	350.05	13.69	363.74
131 MOWATA GAS COMPANY	279.03	17.75	296.78
132 MUNFORD, TN, CITY OF	11,342.79	956.45	12,299.24
133 MURRAY, KY, CITY OF	26,670.62	2,166.02	28,836.64
134 NATURAL GAS CLEARINGHOUSE	70,883.65	5,696.67	76,580.32
135 NATURAL GAS OF KENTUCKY INC	89.37	7.85	97.22
136 NESI INTEGRATED ENERGY RESRC	1,462.42	92.69	1,555.11
137 NEW JERSEY NATURAL GAS COMPANY	26,519.80	1,491.67	28,011.47
138 NEW YORK STATE ELECTRIC & GAS	83,841.24	6,761.10	90,602.34
139 NEZPIQUE GAS SYSTEM INC	573.24	41.07	614.31
140 NGC TRANSPORTATION INC	26.47	2.30	28.77
141 NIAGARA MOHAWK POWER CORP.	27,727.99	1,424.95	29,152.94
142 NOBLE GAS MARKETING INC	49,276.39	3,967.62	53,244.01
143 NOBLE GAS PIPELINE INC	11,645.52	842.80	12,488.32
144 NORAM ENERGY SERVICES INC.	1,225.75	92.25	1,318.00
145 NORTH ATLANTIC UTILITIES INC.	29,864.35	2,193.15	32,057.50
146 NORTHERN UTILITIES INC	5,394.36	436.87	5,831.23
147 OHIO VALLEY GAS CORPORATION	151,926.03	12,388.54	164,314.57
148 OHIO VALLEY GAS, INC	17,362.69	1,465.15	18,827.84
149 OLIVE BRANCH, MS, CITY OF	31,518.72	2,508.56	34,027.28
150 OWENS CORNING	15,071.95	1,120.36	16,192.31
151 OXY USA INC	90.00	4.30	94.30
152 PANDA ROSEMARY LTD PARTNERSHIP	16,769.07	1,373.57	18,142.64
153 PCS NITROGEN FERTILIZER LP	10,586.15	751.24	11,337.39
154 PEOPLES GAS AND POWER CO INC	17,883.44	1,444.23	19,327.67
155 PEOPLES NATURAL GAS COMPANY	95,833.88	7,833.11	103,666.99
156 PG&E ENERGY TRADING CORP	34,011.94	2,785.14	36,797.08
157 PHILLIPS PETROLEUM COMPANY	3,642.69	190.87	3,833.56
158 POPLAR GROVE UTILITY DISTRICT	5,480.60	462.02	5,942.62
159 POWER RESOURCES OPERATING CO	206.13	10.31	216.44

TEXAS GAS TRANSMISSION CORPORATION
DOCKET NO. RP 97-344
COMPUTATION OF REFUND DUE ON REVENUES COLLECTED SUBJECT TO REFUND DATES
FOR THE PERIOD NOVEMBER 1, 1997 THROUGH NOVEMBER 30, 1998
WITH INTEREST COMPOUNDED QUARTERLY THROUGH JANUARY 13, 1999

CUSTOMER NAME	PRINCIPAL REFUND	INTEREST DUE	TOTAL REFUND DUE
160 PROCTER & GAMBLE COMPANY	15,802.18	1,231.21	17,033.39
161 PROCTER & GAMBLE MFG COMPANY	96.20	6.09	102.29
162 PROLIANCE ENERGY LLC	2,950,889.98	234,149.79	3,185,039.77
163 PROTEIN TECHNOLOGIES INTRNTL	1,654.47	127.05	1,781.52
164 PROVIDENCE ENERGY SERVICES INC	73.77	4.83	78.60
165 PROVIDENCE, KY, CITY OF	7,608.49	614.65	8,223.14
166 PUBLIC SERVICE CO OF NC INC	39,102.55	3,176.16	42,278.71
167 PUBLIC SERVICE ELECTRIC & GAS	574,494.09	46,448.44	620,942.53
168 RELIUS ENERGY LLC	17,112.30	1,599.41	18,711.71
169 RICHIE GAS SYSTEM INC	83.20	5.69	88.89
170 RIPLEY, TN, CITY OF	19,453.66	1,563.22	21,016.88
171 ROANOKE FARM GAS CO., INC	44.91	2.88	47.79
172 ROCHESTER GAS & ELECTRIC CORP.	27,566.99	2,224.56	29,791.55
173 SIGCORP ENERGY SERVICES INC	29,771.54	2,738.19	32,509.73
174 SIGCORP GAS MARKETING INC	64,262.22	4,694.79	68,957.01
175 SONAT MARKETING COMPANY	2,889.84	266.20	3,156.04
176 SONAT MARKETING COMPANY L.P.	115.40	8.62	124.02
177 SOUTH EASTERN IN NATURAL GAS	11,079.67	939.01	12,018.68
178 SOUTH FULTON, TN, CITY OF	3,545.15	298.67	3,843.82
179 SOUTH JERSEY GAS COMPANY	138,921.27	11,248.76	150,170.03
180 SOUTHERN GAS CO OF DELAWARE	58,366.95	4,812.26	63,179.21
181 SOUTHERN IN GAS & ELECTRIC CO.	783,111.20	61,098.32	844,209.52
182 STURGIS, KY, CITY OF	5,199.42	413.30	5,612.72
183 SWITZERLAND COUNTY NATURAL GAS	3,172.75	259.30	3,432.05
184 TEXACO NATURAL GAS INC	1,469.12	98.76	1,567.88
185 TEXAS EASTERN TRANSMISSION	575,885.86	47,747.16	623,633.02
186 TEXAS-OHIO GAS INC.	1,990.74	167.81	2,158.55
187 TOYOTA MOTOR MANUFACTURING	6,835.32	505.20	7,340.52
188 TPC CORPORATION	726.85	53.68	780.53
189 TRANS LOUISIANA GAS COMPANY	1,659.73	125.37	1,785.10
190 TRANSCANADA ENERGY MKTG USA	377.00	20.82	397.82
191 TRANSCANADA GAS PROCESSING USA	12.50	0.60	13.10
192 TRANSCONTINENTAL GAS PIPE LINE	175,109.26	14,148.55	189,257.81
193 TXG GAS MARKETING COMPANY	3,862.89	281.93	4,144.82
194 UGI UTILITIES INC	119,011.03	9,779.01	128,790.04
195 UNION LIGHT, HEAT & POWER CO	128,478.15	10,430.44	138,908.59
196 UNION OIL CO OF CALIFORNIA	1,674.46	122.57	1,797.03
197 UNION PACIFIC FUELS INC	39,863.42	3,135.05	42,998.47
198 UNION PACIFIC RESOURCE COMPANY	30,975.60	2,161.95	33,137.55
199 UNITED CITIES GAS COMPANY	29,881.43	2,494.50	32,375.93
200 USG INTERIORS INC.	12,627.15	949.80	13,576.95
201 VALLEY GAS, INC	2,915.70	239.76	3,155.46
202 VASTAR GAS MARKETING INC	1,339.24	90.25	1,429.49
203 VOLUNTEER ENERGY CORPORATION	70.69	4.58	75.27
204 WESTERN GAS RESOURCES INC	390.00	22.12	412.12
205 WESTERN KENTUCKY GAS COMPANY	1,037,233.51	81,748.66	1,118,982.17
206 WESTLAKE CHEMICAL CORPORATION	621.79	46.84	668.63
207 WESTVACO CORPORATION	19,073.03	1,478.87	20,551.90
208 WILLIAMS ENERGY SERVICES CO	62,922.73	5,225.31	68,148.04
209 WINSTONVILLE, MS, TOWN OF	311.24	-	311.24
210 WOODWARD MARKETING LLC	1,728.84	105.46	1,834.30
Total	$ 15,936,726.68	$ 1,279,346.04	$ 17,216,072.72

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: System Supply
Rate Schedule: No-Notice Service

Contract Number: 000210
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
11/1997	COM	422,423	0.027400	$11,574.39	0.026300	$11,109.72	$464.67				
	RESD	(9,000)	0.090000	$(810.00)	0.090000	$(810.00)	$ 0.00				
	RESV	1,365,000	0.407200	$555,828.00	0.332200	$453,453.00	$102,375.00				
	Total			$566,592.39		$463,752.72	$102,839.67	12/22/1997	$102,839.67	$9,639.25	$112,478.92
									$102,839.67	$9,639.25	$112,478.92
12/1997	COM	598,826	0.027400	$16,407.84	0.026300	$15,749.12	$658.72				
	RESD	(24,800)	0.050000	$(1,240.00)	0.050000	$(1,240.00)	$ 0.00				
	RESD	(12,400)	0.080000	$(992.00)	0.080000	$(992.00)	$ 0.00				
	RESV	1,410,500	0.345000	$486,622.50	0.332200	$468,568.10	$18,054.40				
	Total			$500,798.34		$482,085.22	$18,713.12	01/20/1998	$18,713.12	$1,617.83	$20,330.95
									$18,713.12	$1,617.83	$20,330.95
01/1998	COM	477,958	0.027400	$13,096.05	0.026300	$12,570.29	$525.76				
	RESD	(9,300)	0.020000	$(186.00)	0.020000	$(186.00)	$ 0.00				
	RESD	(24,800)	0.040000	$(992.00)	0.040000	$(992.00)	$ 0.00				
	RESD	(13,175)	0.070000	$(922.25)	0.070000	$(922.25)	$ 0.00				
	RESV	1,410,500	0.345000	$486,622.50	0.332200	$468,568.10	$18,054.40				
	Total			$497,618.30		$479,038.14	$18,580.16	02/20/1998	$18,580.16	$1,461.97	$20,042.13
									$18,580.16	$1,461.97	$20,042.13
02/1998	COM	269,346	0.027400	$7,380.08	0.026300	$7,083.80	$296.28				
	RESD	(52,420)	0.015000	$(786.30)	0.015000	$(786.30)	$ 0.00				
	RESV	1,274,000	0.345000	$439,530.00	0.332200	$423,222.80	$16,307.20				
	Total			$446,123.78		$429,520.30	$16,603.48	03/20/1998	$16,603.48	$1,190.83	$17,794.31
									$16,603.48	$1,190.83	$17,794.31
03/1998	COM	405,802	0.027400	$11,118.98	0.026300	$10,672.60	$446.38				
	RESD	(310,000)	0.010000	$(3,100.00)	0.010000	$(3,100.00)	$ 0.00				
	RESD	(50,034)	0.015000	$(750.51)	0.015000	$(750.51)	$ 0.00				
	RESV	1,410,500	0.345000	$486,622.50	0.332200	$468,568.10	$18,054.40				
	Total			$493,890.97		$475,390.19	$18,500.78	04/21/1998	$18,500.78	$1,179.24	$19,680.02
									$18,500.78	$1,179.24	$19,680.02
04/1998	COM	205,993	0.027400	$5,644.20	0.026300	$5,417.61	$226.59				

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Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: System Supply
Rate Schedule: No Notice Service

Contract Number: 000210
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
04/1998	RESD	(150,000)	0.010000	$(1,500.00)	0.010000	$(1,500.00)	$ 0.00				
	RESD	(125,010)	0.015000	$(1,875.15)	0.015000	$(1,875.15)	$ 0.00				
	RESV	1,091,010	0.345000	$376,398.45	0.332200	$362,433.52	$13,964.93				
	UO	4,236	0.372400	$1,577.49	0.358500	$1,518.61	$58.88				
	Total			$380,244.99		$365,994.59	$14,250.40	05/21/1998	$14,250.40	$804.47	$15,054.87
									$14,250.40	$804.47	$15,054.87
05/1998	COM	93,474	0.027400	$2,561.18	0.026300	$2,458.36	$102.82				
	RESD	(173,910)	0.015000	$(2,608.65)	0.015000	$(2,608.65)	$ 0.00				
	RESV	691,052	0.345000	$238,412.94	0.332200	$229,567.47	$8,845.47				
	Total			$238,365.47		$229,417.18	$8,948.29	06/22/1998	$8,948.29	$434.75	$9,383.04
									$8,948.29	$434.75	$9,383.04
06/1998	COM	51,481	0.026100	$1,151.95	0.026100	$1,151.95	$ 0.00				
	RESD	(90,000)	0.015000	$(1,350.00)	0.015000	$(1,350.00)	$ 0.00				
	RESV	668,760	0.320900	$214,605.08	0.320900	$214,605.08	$ 0.00				
	Total			$214,609.03		$214,609.03	$ 0.00		$ 0.00	$ 0.00	$ 0.00
07/1998	COM	453	0.018400	$ 8.34	0.018400	$ 8.34	$ 0.00				
	COM	69,009	0.023500	$1,621.71	0.023500	$1,621.71	$ 0.00				
	RESV	691,052	0.315800	$218,234.22	0.315800	$218,234.22	$ 0.00				
	Total			$219,864.27		$219,864.27	$ 0.00		$ 0.00	$ 0.00	$ 0.00
08/1998	COM	19,833	0.023500	$466.08	0.023500	$466.08	$ 0.00				
	RESV	691,052	0.315800	$218,234.22	0.315800	$218,234.22	$ 0.00				
	Total			$218,700.30		$218,700.30	$ 0.00		$ 0.00	$ 0.00	$ 0.00
09/1998	COM	9,919	0.002800	$27.77	0.002800	$27.77	$ 0.00				
	COM	99,745	0.023500	$2,344.02	0.023500	$2,344.02	$ 0.00				
	RESV	668,760	0.315800	$211,194.41	0.315800	$211,194.41	$ 0.00				
	Total			$213,566.20		$213,566.20	$ 0.00		$ 0.00	$ 0.00	$ 0.00
10/1998	COM	121,681	0.023500	$2,859.51	0.023500	$2,859.51	$ 0.00				
	RESD	(155,000)	0.005000	$(775.00)	0.005000	$(775.00)	$ 0.00				

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Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: System Supply
Rate Schedule: No-Notice Service

Contract Number: 000210
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
10/1998	RESV	1,245,487	0.315800	$393,324.79	0.315800	$393,324.79	$ 0.00				
	Total			$395,409.30		$395,409.30	$ 0.00		$ 0.00	$ 0.00	$ 0.00
11/1998	COM	32,398	0.002800	$90.71	0.002800	$90.71	$ 0.00				
	COM	306,265	0.023500	$7,197.23	0.023500	$7,197.23	$ 0.00				
	RESD	(150,000)	0.010000	$(1,500.00)	0.010000	$(1,500.00)	$ 0.00				
	RESV	1,365,000	0.315800	$431,067.00	0.315800	$431,067.00	$ 0.00				
	Total			$436,854.94		$436,854.94	$ 0.00		$ 0.00	$ 0.00	$ 0.00
	Subcontract Total			$4,822,638.28		$4,624,202.38	$198,435.90		$198,435.90	$16,328.34	$214,764.24
	Contract Total			$4,822,638.28		$4,624,202.38	$198,435.90		$198,435.90	$16,328.34	$214,764.24

Demand	$ 195,714.68	$ 16,104.42	$ 211,819.10
Commodity	2,721.22	223.92	2,945.14
	$ 198,435.90	$ 16,328.34	$ 214,764.24

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: System Supply
Rate Schedule: No-Notice Service

Contract Number: 000340
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
11/1997	COM	1,816,696	0.033500	$60,859.32	0.031000	$56,317.59	$4,541.73				
	COM	(7,766)	0.033600	$(260.94)	0.033600	$(260.94)	$ 0.00				
	RESD	(36,840)	0.120000	$(4,420.80)	0.120000	$(4,420.80)	$ 0.00				
	RESV	2,430,000	0.454000	$1,103,220.00	0.366200	$889,866.00	$213,354.00				
	UO	7,791	0.413200	$3,219.24	0.413200	$3,219.24	$ 0.00				
	Total			$1,162,616.82		$944,721.09	$217,895.73	12/22/1997	$217,895.73	$20,423.54	$238,319.27
									$217,895.73	$20,423.54	$238,319.27
12/1997	COM	1,874,933	0.033500	$62,810.26	0.031000	$58,122.92	$4,687.34				
	COM	256	0.033600	$ 8.60	0.033600	$ 8.60	$ 0.00				
	RESD	(23,250)	0.100000	$(2,325.00)	0.100000	$(2,325.00)	$ 0.00				
	RESV	2,511,000	0.390000	$979,290.00	0.366200	$919,528.20	$59,761.80				
	UO	16,055	0.487600	$7,828.42	0.397200	$6,377.05	$1,451.37				
	Total			$1,047,612.28		$981,711.77	$65,900.51	01/20/1998	$65,900.51	$5,697.34	$71,597.85
									$65,900.51	$5,697.34	$71,597.85
01/1998	COM	1,854,642	0.033500	$62,110.50	0.031000	$57,493.92	$4,636.58				
	RESV	2,511,000	0.390000	$979,290.00	0.366200	$919,528.20	$59,761.80				
	Total			$1,041,420.50		$977,022.12	$64,398.38	02/20/1998	$64,398.38	$5,067.13	$69,465.51
									$64,398.38	$5,067.13	$69,465.51
02/1998	COM	1,405,560	0.033500	$47,086.26	0.031000	$43,572.37	$3,513.89				
	RESD	(52,416)	0.020000	$(1,048.32)	0.020000	$(1,048.32)	$ 0.00				
	RESV	2,268,000	0.390000	$884,520.00	0.366200	$830,541.60	$53,978.40				
	UO	1,333	0.423500	$564.53	0.397200	$529.47	$35.06				
	Total			$931,122.47		$873,595.12	$57,527.35	03/20/1998	$57,527.35	$4,125.92	$61,653.27
									$57,527.35	$4,125.92	$61,653.27
03/1998	COM	904,184	0.033500	$30,290.16	0.031000	$28,029.71	$2,260.45				
	RESD	(54,475)	0.020000	$(1,089.50)	0.020000	$(1,089.50)	$ 0.00				
	RESV	2,511,000	0.390000	$979,290.00	0.366200	$919,528.20	$59,761.80				
	UO	14,174	0.423500	$6,002.69	0.397200	$5,629.91	$372.78				
	Total			$1,014,493.35		$952,098.32	$62,395.03	04/21/1998	$62,395.03	$3,977.09	$66,372.12
									$62,395.03	$3,977.09	$66,372.12

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Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: System Supply
Rate Schedule: No-Notice Service

Contract Number: 000340
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
04/1998	COM	748,266	0.033500	$25,066.92	0.031000	$23,196.25	$1,870.67				
	RESC	(77,030)	0.010000	$(770.30)	0.010000	$(770.30)	$ 0.00				
	RESD	(230,250)	0.010000	$(2,302.50)	0.010000	$(2,302.50)	$ 0.00				
	RESD	(30,000)	0.020000	$(600.00)	0.020000	$(600.00)	$ 0.00				
	RESV	2,430,000	0.390000	$947,700.00	0.366200	$889,866.00	$57,834.00				
	UO	6,283	0.423500	$2,660.85	0.397200	$2,495.61	$165.24				
								[illegible]	[illegible]	[illegible]	[illegible]
	Total			$971,754.97		$911,885.06	$59,869.91		$59,869.91	$3,379.81	$63,249.72
05/1998	COM	437,325	0.033500	$14,650.39	0.031000	$13,557.07	$1,093.32				
	RESD	(130,000)	0.020000	$(2,600.00)	0.020000	$(2,600.00)	$ 0.00				
	RESV	2,088,625	0.390000	$814,563.75	0.366200	$764,854.48	$49,709.27				
								06/22/1998	$50,802.59	$2,468.29	$53,270.88
	Total			$826,614.14		$775,811.55	$50,802.59		$50,802.59	$2,468.29	$53,270.88
06/1998	COM	709,229	0.031000	$21,986.10	0.031000	$21,986.10	$ 0.00				
	COM	27,507	0.033500	$921.48	0.031000	$852.72	$68.76				
	COM	3,012	0.033600	$101.20	0.033600	$101.20	$ 0.00				
	RESV	2,021,250	0.354900	$717,341.63	0.354900	$717,341.63	$ 0.00				
								07/20/1998	$68.76	$ 2.87	$71.63
	Total			$740,350.41		$740,281.65	$68.76		$68.76	$ 2.87	$71.63
07/1998	COM	59,039	0.018400	$1,086.32	0.018400	$1,086.32	$ 0.00				
	COM	679,640	0.028200	$19,165.86	0.028200	$19,165.86	$ 0.00				
	COM	5,389	0.033500	$180.53	0.031000	$167.06	$13.47				
	RESV	2,088,625	0.349800	$730,601.03	0.349800	$730,601.03	$ 0.00				
								08/20/1998	$13.47	$ 0.47	$13.94
	Total			$751,033.74		$751,020.27	$13.47		$13.47	$ 0.47	$13.94
08/1998	COM	22,569	0.002800	$63.19	0.002800	$63.19	$ 0.00				
	COM	970,280	0.028200	$27,361.90	0.028200	$27,361.90	$ 0.00				
	COM	672	0.031000	$20.83	0.031000	$20.83	$ 0.00				
	COM	65	0.033500	$ 2.18	0.031000	$ 2.02	$ 0.16				
	RESV	2,088,625	0.349800	$730,601.03	0.349800	$730,601.03	$ 0.00				
								09/21/1998	$ 0.16	$ 0.00	$ 0.16

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: System Supply
Rate Schedule: No-Notice Service

Contract Number: 000340
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
	Total			$758,049.13		$758,048.97	$ 0.16		$ 0.16	$ 0.00	$ 0.16
09/1998	COM	114,108	0.002800	$319.50	0.002800	$319.50	$ 0.00				
	COM	473,525	0.028200	$13,353.39	0.028200	$13,353.39	$ 0.00				
	COM	414	0.033500	$13.87	0.031000	$12.83	$ 1.04				
	RESV	2,021,250	0.349800	$707,033.25	0.349800	$707,033.25	$ 0.00				
	Total			$720,720.01		$720,718.97	$ 1.04	10/20/1998	$ 1.04	$ 0.02	$ 1.06
									$ 1.04	$ 0.02	$ 1.06
10/1998	COM	634,734	0.028200	$17,899.50	0.028200	$17,899.50	$ 0.00				
	RESD	(155,000)	0.005000	$(775.00)	0.005000	$(775.00)	$ 0.00				
	RESV	2,511,000	0.349800	$878,347.80	0.349800	$878,347.80	$ 0.00				
	Total			$895,472.30		$895,472.30	$ 0.00		$ 0.00	$ 0.00	$ 0.00
11/1998	COM	13,138	0.002800	$36.79	0.002800	$36.79	$ 0.00				
	COM	1,174,501	0.028200	$33,120.92	0.028200	$33,120.92	$ 0.00				
	RESD	(110,000)	0.010000	$(1,100.00)	0.010000	$(1,100.00)	$ 0.00				
	RESV	2,430,000	0.349800	$850,014.00	0.349800	$850,014.00	$ 0.00				
	Total			$881,871.71		$881,871.71	$ 0.00		$ 0.00	$ 0.00	$ 0.00
	Subcontract Total			$11,743,131.83		$11,164,258.90	$578,872.93		$578,872.93	$45,142.48	$624,015.41
	Contract Total			$11,743,131.83		$11,164,258.90	$578,872.93		$578,872.93	$45,142.48	$624,015.41

	Payment Applied To Principal Refund	Interest Due	Total Refund Due
Demand	$556,125.52	$43,373.24	$599,558.76
Commodity	22,687.41	1,769.24	24,456.65
	$578,872.93	$45,142.48	$624,015.41

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: System Supply
Rate Schedule: No-Notice Service

Contract Number: 000435
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
11/1997	COM	143,535	0.040300	$5,784.46	0.036100	$5,181.61	$602.85				
	RESV	405,000	0.544300	$220,441.50	0.426000	$172,530.00	$47,911.50				
	Total			$226,225.96		$177,711.61	$48,514.35	12/22/1997	$48,514.35	$4,547.31	$53,061.66
									$48,514.35	$4,547.31	$53,061.66
12/1997	COM	118,899	0.040300	$4,791.63	0.036100	$4,292.25	$499.38				
	RESV	418,500	0.450000	$188,325.00	0.426000	$178,281.00	$10,044.00				
	Total			$193,116.63		$182,573.25	$10,543.38	01/20/1998	$10,543.38	$911.52	$11,454.90
									$10,543.38	$911.52	$11,454.90
01/1998	COM	184,725	0.040300	$7,444.42	0.036100	$6,668.57	$775.85				
	RESV	418,500	0.450000	$188,325.00	0.426000	$178,281.00	$10,044.00				
	Total			$195,769.42		$184,949.57	$10,819.85	02/20/1998	$10,819.85	$851.35	$11,671.20
									$10,819.85	$851.35	$11,671.20
02/1998	COM	124,160	0.040300	$5,003.65	0.036100	$4,482.17	$521.48				
	RESV	378,000	0.450000	$170,100.00	0.426000	$161,028.00	$9,072.00				
	Total			$175,103.65		$165,510.17	$9,593.48	03/20/1998	$9,593.48	$688.05	$10,281.53
									$9,593.48	$688.05	$10,281.53
03/1998	COM	136,421	0.040300	$5,497.76	0.036100	$4,924.80	$572.96				
	RESV	418,500	0.450000	$188,325.00	0.426000	$178,281.00	$10,044.00				
	Total			$193,822.76		$183,205.80	$10,616.96	04/21/1998	$10,616.96	$676.74	$11,293.70
									$10,616.96	$676.74	$11,293.70
04/1998	COM	88,719	0.040300	$3,575.37	0.036100	$3,202.75	$372.62				
	RESV	265,140	0.450000	$119,313.00	0.426000	$112,949.64	$6,363.36				
	Total			$122,888.37		$116,152.39	$6,735.98	05/21/1998	$6,735.98	$380.25	$7,116.23
									$6,735.98	$380.25	$7,116.23
05/1998	COM	24,312	0.040300	$979.78	0.036100	$877.66	$102.12				
	RESD	(31,000)	0.040000	$(1,240.00)	0.040000	$(1,240.00)	$ 0.00				
	RESV	143,375	0.450000	$64,518.75	0.426000	$61,077.75	$3,441.00				
								06/22/1998	$3,543.12	$172.13	$3,715.25

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Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: System Supply
Rate Schedule: No-Notice Service

Contract Number: 000435
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
	Total			$64,258.53		$60,715.41	$3,543.12		$3,543.12	$172.13	$3,715.25
06/1998	COM	20,898	0.036100	$754.41	0.036100	$754.41	$ 0.00				
	RESD	(53,610)	0.030000	$(1,608.30)	0.030000	$(1,608.30)	$ 0.00				
	RESV	138,750	0.414700	$57,539.63	0.414700	$57,539.63	$ 0.00				
	Total			$56,685.74		$56,685.74	$ 0.00		$ 0.00	$ 0.00	$ 0.00
07/1998	COM	3,559	0.018400	$65.49	0.018400	$65.49	$ 0.00				
	COM	49,465	0.033300	$1,647.18	0.033300	$1,647.18	$ 0.00				
	RESV	143,375	0.409600	$58,726.40	0.409600	$58,726.40	$ 0.00				
	Total			$60,439.07		$60,439.07	$ 0.00		$ 0.00	$ 0.00	$ 0.00
08/1998	COM	123,425	0.033300	$4,110.05	0.033300	$4,110.05	$ 0.00				
	RESV	143,375	0.409600	$58,726.40	0.409600	$58,726.40	$ 0.00				
	UO	2,187	0.442900	$968 62	0.442900	$968.62	$ 0.00				
	Total			$63,805.07		$63,805.07	$ 0.00		$ 0.00	$ 0.00	$ 0.00
09/1998	COM	109,758	0.033300	$1,654.94	0.033300	$1,654.94	$ 0.00				
	RESV	138,750	0.409600	$56,832.00	0.409600	$56,832.00	$ 0.00				
	UO	567	0.442900	$251.12	0.442900	$251.12	$ 0.00				
	Total			$60,738.06		$60,738.06	$ 0.00		$ 0.00	$ 0.00	$ 0.00
10/1998	COM	73,683	0.033300	$2,453.63	0.033300	$2,453.63	$ 0.00				
	RESV	309,504	0.409600	$126,772.84	0.409600	$126,772.84	$ 0.00				
	UO	1,302	0.442900	$576 66	0.442900	$576.66	$ 0.00				
	Total			$129,803.13		$129,803.13	$ 0.00		$ 0.00	$ 0.00	$ 0.00
11/1998	COM	138,025	0.033300	$4,596.22	0.033300	$4,596.22	$ 0.00				
	RESV	405,000	0.409600	$165,888.00	0.409600	$165,888.00	$ 0.00				
	Total			$170,484.22		$170,484.22	$ 0.00		$ 0.00	$ 0.00	$ 0.00
	Subcontract Total			$1,713,140.61		$1,612,773.49	$100,367.12		$100,367.12	$8,227.35	$108,594.47
	Contract Total			$1,713,140.61		$1,612,773.49	$100,367.12		$100,367.12	$8,227.35	$108,594.47
								Demand	$ 96,919.86	$ 7,944.77	$ 104,864.63
								Commodity	3,447.26	282.58	3,729.84
									$ 100,367.12	$ 8,227.35	$ 108,594.47

Exhibit E
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Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: Firm System Supply
Rate Schedule: Firm Transportation

Contract Number: 001355
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
11/1997	COM	149,130	0.028000	$4,175.64	0.025700	$3,832.64	$343.00				
	COM	68,140	0.030100	$2,051.01	0.027600	$1,880.66	$170.35				
	RESV	450,000	0.350700	$157,815.00	0.269300	$121,185.00	$16,630.00				
	Total			$164,041.65		$126,898.30	$37,143.35	12/22/1997	$37,143.35	$3,481.47	$40,624.82
									$37,143.35	$3,481.47	$40,624.82
12/1997	COM	154,101	0.028000	$4,314.83	0.025700	$3,960.40	$354.43				
	COM	150,908	0.030100	$4,542.33	0.027600	$4,165.06	$377.27				
	RESV	465,000	0.305000	$141,825.00	0.269300	$125,224.50	$16,600.50				
	Total			$150,682.16		$133,349.96	$17,332.20	01/20/1998	$17,332.20	$1,498.43	$18,830.63
									$17,332.20	$1,498.43	$18,830.63
01/1998	COM	6,992	0.011100	$77.61	0.010000	$69.92	$7.69				
	COM	154,101	0.028000	$4,314.83	0.025700	$3,960.40	$354.43				
	COM	107,096	0.030100	$3,223.59	0.027600	$2,955.85	$267.74				
	RESD	(50,158)	0.080000	$(4,012.64)	0.080000	$(4,012.64)	$0.00				
	RESV	465,000	0.305000	$141,825.00	0.269300	$125,224.50	$16,600.50				
	Total			$145,428.39		$128,198.03	$17,230.36	02/20/1998	$17,230.36	$1,355.76	$18,586.12
									$17,230.36	$1,355.76	$18,586.12
02/1998	COM	139,188	0.028000	$3,897.26	0.025700	$3,577.13	$320.13				
	COM	111,964	0.030100	$3,370.12	0.027600	$3,090.21	$279.91				
	RESV	420,000	0.305000	$128,100.00	0.269300	$113,106.00	$14,994.00				
	Total			$135,367.38		$119,773.34	$15,594.04	03/20/1998	$15,594.04	$1,118.41	$16,712.45
									$15,594.04	$1,118.41	$16,712.45
03/1998	COM	154,101	0.028000	$4,314.83	0.025700	$3,960.40	$354.43				
	COM	153,166	0.030100	$4,610.30	0.027600	$4,227.38	$382.92				
	RESV	465,000	0.305000	$141,825.00	0.269300	$125,224.50	$16,600.50				
	Total			$150,750.13		$133,412.28	$17,337.85	04/21/1998	$17,337.85	$1,105.13	$18,442.98
									$17,337.85	$1,105.13	$18,442.98
04/1998	COM	148,920	0.028000	$4,169.76	0.025700	$3,827.24	$342.52				
	RESD	(270,000)	0.020000	$(5,400.00)	0.020000	$(5,400.00)	$0.00				
	RESV	450,000	0.305000	$137,250.00	0.269300	$121,185.00	$16,065.00				

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: Firm System Supply
Rate Schedule: Firm Transportation

Contract Number: 003355
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
								05/21/1998	$16,407.52	$926.25	$17,333.77
	Total			$116,019.76		$119,612.24	$16,407.52		$16,407.52	$926.25	$17,333.77
05/1998	COM	144,618	0.028000	$4,049.30	0.025700	$3,716.68	$332.62				
	COM	3,068	0.030100	$92.35	0.027600	$84.68	$ 7.67				
	RESD	(303,800)	0.020000	$(6,076.00)	0.020000	$(6,076.00)	$ 0.00				
	RESV	465,000	0.305000	$141,825.00	0.269300	$125,224.50	$16,600.50				
								06/22/1998	$16,940.79	$823.07	$17,763.86
	Total			$139,890.65		$122,949.86	$16,940.79		$16,940.79	$823.07	$17,763.86
06/1998	COM	143,704	0.025700	$3,693.19	0.025700	$3,693.19	$ 0.00				
	COM	(4)	0.030100	$(0.12)	0.027600	$(0.11)	$(0.01)				
	RESD	(294,000)	0.020000	$(5,880.00)	0.020000	$(5,880.00)	$ 0.00				
	RESV	450,000	0.258000	$116,100.00	0.258000	$116,100.00	$ 0.00				
							$ 0.00	07/20/1998	$(0.01)	$ 0.00	$(0.01)
	Total			$113,913.07		$113,913.08	$(0.01)		$(0.01)	$ 0.00	$(0.01)
07/1998	COM	49,907	0.010800	$539.00	0.010800	$539.00	$ 0.00				
	COM	9,486	0.012800	$121.42	0.012800	$121.42	$ 0.00				
	COM	122,309	0.022900	$2,800.87	0.022900	$2,800.87	$ 0.00				
	COM	96,386	0.024800	$2,390.37	0.024800	$2,390.37	$ 0.00				
	RESV	465,000	0.252900	$117,598.50	0.252900	$117,598.50	$ 0.00				
							$ 0.00				
	Total			$123,450.16		$123,450.16	$ 0.00		$ 0.00	$ 0.00	$ 0.00
08/1998	COM	172,535	0.002600	$448.59	0.002600	$448.59	$ 0.00				
	COM	121,032	0.022900	$2,771.63	0.022900	$2,771.63	$ 0.00				
	COM	19,842	0.024800	$492.08	0.024800	$492.08	$ 0.00				
	COM	1	0.030100	$ 0.03	0.027600	$ 0.03	$ 0.00				
	RESV	465,000	0.252900	$117,598.50	0.252900	$117,598.50	$ 0.00				
							$ 0.00				
	Total			$121,310.83		$121,310.83	$ 0.00		$ 0.00	$ 0.00	$ 0.00
09/1998	COM	212,247	0.002600	$551.84	0.002600	$551.84	$ 0.00				
	COM	14,000	0.010800	$151.20	0.010800	$151.20	$ 0.00				
	COM	61,672	0.022900	$1,412.29	0.022900	$1,412.29	$ 0.00				
	COM	34,227	0.024800	$848.83	0.024800	$848.83	$ 0.00				
							$ 0.00				

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: Firm System Supply
Rate Schedule: Firm Transportation

Contract Number: 003155
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
09/1998	RESV	450,000	0.252900	$113,805.00	0.252900	$113,805.00	$ 0.00				
	Total			$116,769.16		$116,769.16	$ 0.00		$ 0.00	$ 0.00	$ 0.00
10/1998	COM	25,948	0.007200	$186.83	0.007200	$186.83	$ 0.00				
	COM	6,600	0.010800	$71.28	0.010800	$71.28	$ 0.00				
	COM	12,982	0.022900	$297.29	0.022900	$297.29	$ 0.00				
	COM	20,748	0.024800	$514.55	0.024800	$514.55	$ 0.00				
	RESV	465,000	0.252900	$117,598.50	0.252900	$117,598.50	$ 0.00				
	Total			$118,668.45		$118,668.45	$ 0.00		$ 0.00	$ 0.00	$ 0.00
11/1998	COM	40,944	0.002600	$106.45	0.002600	$106.45	$ 0.00				
	COM	4,830	0.010800	$52.16	0.010800	$52.16	$ 0.00				
	COM	94,325	0.022900	$2,160.04	0.022900	$2,160.04	$ 0.00				
	COM	51,227	0.024800	$1,270.43	0.024800	$1,270.43	$ 0.00				
	RESD	(150,000)	0.010000	$(1,500.00)	0.010000	$(1,500.00)	$ 0.00				
	RESV	450,000	0.252900	$113,805.00	0.252900	$113,805.00	$ 0.00				
	Total			$115,894.08		$115,894.08	$ 0.00		$ 0.00	$ 0.00	$ 0.00
	Subcontract Total			$1,732,185.87		$1,594,199.77	$137,986.10		$137,986.10	$10,308.52	$148,294.62
	Contract Total			$1,732,185.87		$1,594,199.77	$137,986.10		$137,986.10	$10,308.52	$148,294.62

	Payment Applied To Principal Refund	Interest Due	Total Refund Due
Demand	$134,091.00	$10,017.53	$144,108.53
Commodity	3,895.10	290.99	4,186.09
	$137,986.10	$10,308.52	$148,294.62

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: Firm System Supply
Rate Schedule: Firm Transportation

Contract Number: 003819
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
11/1997	COM	34,107	0.033300	$1,135.76	0.030700	$1,047.08	$88.68				
	RESV	105,000	0.410500	$43,102.50	0.322500	$33,862.50	$9,240.00				
	Total			$44,238.26		$34,909.58	$9,328.68	12/22/1997	$9,328.68	$874.19	$10,203.07
									$9,328.68	$874.39	$10,203.07
12/1997	COM	105,040	0.033300	$3,497.83	0.030700	$3,224.73	$273.10				
	RESV	108,500	0.335000	$36,347.50	0.322500	$34,991.25	$1,356.25				
	Total			$39,845.33		$38,215.98	$1,629.35	01/20/1998	$1,629.35	$140.85	$1,770.20
									$1,629.35	$140.85	$1,770.20
01/1998	COM	52,353	0.033300	$1,743.35	0.030700	$1,607.24	$136.11				
	RESV	108,500	0.335000	$36,347.50	0.322500	$34,991.25	$1,356.25				
	Total			$38,090.85		$36,598.49	$1,492.36	02/20/1998	$1,492.36	$117.42	$1,609.78
									$1,492.36	$117.42	$1,609.78
02/1998	COM	4,200	0.013700	$57.54	0.012200	$51.24	$ 6.30				
	COM	36,841	0.033300	$1,226.81	0.030700	$1,131.02	$95.79				
	RESV	98,000	0.335000	$32,830.00	0.322500	$31,605.00	$1,225.00				
	Total			$34,114.35		$32,787.26	$1,327.09	03/20/1998	$1,327.09	$95.20	$1,422.29
									$1,327.09	$95.20	$1,422.29
03/1998	COM	21,721	0.033300	$723.31	0.030700	$666.81	$56.48				
	RESV	108,500	0.335000	$36,347.50	0.322500	$34,991.25	$1,356.25				
	Total			$37,070.81		$35,658.08	$1,412.73	04/21/1998	$1,412.73	$90.04	$1,502.77
									$1,412.73	$90.04	$1,502.77
04/1998	RESD	(105,000)	0.025000	$(2,625.00)	0.025000	$(2,625.00)	$ 0.00				
	RESV	105,000	0.335000	$35,175.00	0.322500	$33,862.50	$1,312.50				
	Total			$32,550.00		$31,237.50	$1,312.50	05/21/1998	$1,312.50	$74.09	$1,386.59
									$1,312.50	$74.09	$1,386.59
05/1998	RESD	(108,500)	0.025000	$(2,712.50)	0.025000	$(2,712.50)	$ 0.00				
	RESV	108,500	0.335000	$36,347.50	0.322500	$34,991.25	$1,356.25				
								06/22/1998	$1,356.25	$65.91	$1,422.16

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: Firm System Supply
Rate Schedule: Firm Transportation

Contract Number: 001819
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
	Total			$33,615.00		$32,278.75	$1,356.25		$1,356.25	$65.91	$1,422.16
06/1998	RESD	(36,400)	0.030000	$(1,092.00)	0.030000	$(1,092.00)	$ 0.00				
	RESV	105,000	0.311200	$32,676.00	0.311200	$32,676.00	$ 0.00				
	Total			$31,584.00		$31,584.00	$ 0.00		$ 0.00	$ 0.00	$ 0.00
07/1998	COM	3,500	0.010800	$37.80	0.010800	$37.80	$ 0.00				
	COM	14,449	0.027900	$403.13	0.027900	$403.13	$ 0.00				
	RESV	108,500	0.306100	$33,211.85	0.306100	$33,211.85	$ 0.00				
	Total			$33,652.78		$33,652.78	$ 0.00		$ 0.00	$ 0.00	$ 0.00
08/1998	COM	108,004	0.027900	$3,013.31	0.027900	$3,013.31	$ 0.00				
	RESV	108,500	0.306100	$33,211.85	0.306100	$33,211.85	$ 0.00				
	Total			$36,225.16		$36,225.16	$ 0.00		$ 0.00	$ 0.00	$ 0.00
09/1998	COM	97,561	0.027900	$2,721.95	0.027900	$2,721.95	$ 0.00				
	RESV	105,000	0.306100	$32,140.50	0.306100	$32,140.50	$ 0.00				
	Total			$34,862.45		$34,862.45	$ 0.00		$ 0.00	$ 0.00	$ 0.00
10/1998	COM	4,979	0.025100	$124.97	0.025100	$124.97	$ 0.00				
	COM	3,635	0.027900	$101.42	0.027900	$101.42	$ 0.00				
	RESV	108,500	0.306100	$33,211.85	0.306100	$33,211.85	$ 0.00				
	Total			$33,438.24		$33,438.24	$ 0.00		$ 0.00	$ 0.00	$ 0.00
11/1998	COM	4,227	0.024800	$104.83	0.024800	$104.83	$ 0.00				
	COM	42,000	0.025100	$1,054.20	0.025100	$1,054.20	$ 0.00				
	COM	50,117	0.027900	$1,398.26	0.027900	$1,398.26	$ 0.00				
	RESV	105,000	0.306100	$32,140.50	0.306100	$32,140.50	$ 0.00				
	Total			$34,697.79		$34,697.79	$ 0.00		$ 0.00	$ 0.00	$ 0.00
	Subcontract Total			$464,005.02		$446,146.06	$17,858.96		$17,858.96	$1,457.90	$19,316.86
	Contract Total			$464,005.02		$446,146.06	$17,858.96		$17,858.96	$1,457.90	$19,316.86

	Payment Applied	Interest	Total
Demand	$17,202.50	$1,404.31	$18,606.81
Commodity	656.46	53.59	710.05
	$17,858.96	$1,457.90	$19,316.86

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name: REPLACEMENT
Rate Schedule: Firm Transportation

Contract Number: 012471
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
01/1998	RESD	204,600	0.335000	$68,541.00	0.322500	$65,983.50	$2,557.50				
								02/20/1998	$2,557.50	$201.24	$2,758.74
	Total			$68,541.00		$65,983.50	$2,557.50		$2,557.50	$201.24	$2,758.74
02/1998	RESD	92,400	0.335000	$30,954.00	0.322500	$29,799.00	$1,155.00				
								01/20/1998	$1,155.00	$82.83	$1,237.83
	Total			$30,954.00		$29,799.00	$1,155.00		$1,155.00	$82.83	$1,237.83
	Subcontract Total			$99,495.00		$95,782.50	$3,712.50		$3,712.50	$284.07	$3,996.57
	Contract Total			$99,495.00		$95,782.50	$3,712.50		$3,712.50	$284.07	$3,996.57

Texas Gas Transmission Corporation
Schedule of Refund Due Under Docket RP97-344

Customer Name: WESTERN KENTUCKY GAS COMPANY
Enduser Name:
Rate Schedule: Firm Transportation

Contract Number: 011687
Subcontract Number: 0000

Booking Date	Charge Type	MMBtu Volumes	Invoice Rate	Invoice Revenues	Settled Rate	Settled Revenues	Principal Refund	Payment Date	Payment Applied To Principal Refund	Interest Due	Total Refund Due
11/1998	COM	131,526	0.002600	$341.97	0.002600	$341.97	$ 0.00				
	COM	107,758	0.022900	$2,467.66	0.022900	$2,467.66	$ 0.00				
	COM	93,202	0.024800	$2,311.41	0.024800	$2,311.41	$ 0.00				
	RESV	375,000	0.192045	$72,016.88	0.192045	$72,016.88	$ 0.00				
	Total			$77,137.92		$77,137.92	$ 0.00		$ 0.00	$ 0.00	$ 0.00
	Subcontract Total			$77,137.92		$77,137.92	$ 0.00		$ 0.00	$ 0.00	$ 0.00
	Contract Total			$77,137.92		$77,137.92	$ 0.00		$ 0.00	$ 0.00	$ 0.00

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

REFUND PLAN OF)
WESTERN KENTUCKY GAS COMPANY)

Case No. 95-010 CC

CERTIFICATE OF COMPLIANCE

We hereby certify that the refund directed to be made by Order in Case No. 95-010 has been completed in the following manner:

Refund Detail

Customers Refund As Filed	$	38,960.19
Interest Accrued		1,963.00
Carry-over to next GCA Refund		(7,695.14)
Total	$	33,228.05

Refund by Class of Customer

Sales:		
Residential	$	18,848.43
Commercial		10,208.35
Industrial		3,873.12
T-3 Overrun Sales		184.29
T-4 Overrun Sales		113.86
Transportation		-
Total	$	33,228.05

Western Kentucky Gas Company
Large Volume Sales
For the Month of January, 1999

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

Base Charge:

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

				Simple Margin		Non-Commodity Component [2]		Estimated Weighted Average Commodity Gas Cost		Sales Rate	
LVS-1											
Firm Service											
First	300 [1]	Mcf	@	$1.0615	+	$0.7699	+	$1.9796	=	$3.8110	per Mcf
Next	14,700 [1]	Mcf	@	0.5585	+	0.7699	+	1.9796	=	3.3080	per Mcf
All over	15,000	Mcf	@	0.4085	+	0.7699	+	1.9796	=	3.1580	per Mcf
High Load Factor Firm Service											
Demand						$ 4.2809	+	$0.0000	=	$4.2809	per Mcf of daily contract demand
First	300 [1]	Mcf	@	$1.0615	+	$ 0.2150	+	$1.9796	=	$3.2561	per Mcf
Next	14,700 [1]	Mcf	@	0.5585	+	0.2150	+	1.9796	=	2.7531	per Mcf
All over	15,000	Mcf	@	0.4085	+	0.2150	+	1.9796	=	2.6031	per Mcf
LVS-2											
Interruptible Service											
First	15,000	Mcf	@	$0.4936	+	$0.2172	+	$1.9796	=	$2.6904	per Mcf
All over	15,000	Mcf	@	0.3436	+	0.2172	+	1.9796	=	2.5404	per Mcf

True-up Adjustment for previous billing period (s): (0.1873) per Mcf

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

[2] The Non-Commodity Component is from P.S.C. No. 20 Sheet No. 6, effective January 1, 1999.

Western Kentucky Gas Company
Large Volume Sales
Estimated WACOG used for Billing
For the Month of January, 1999

Line No.	Supplier/Type of Service		(A) Estimated MCF Purchased @14.65	(B) Estimated Commodity Cost
1	Estimated Purchases:			
2	Texas Gas Area		1,140,208	$2,163,308.50
3	Tennessee Gas Area		0	0.00
4	Trunkline Gas Area		196,027	369,776.11
5	ANR Pipeline Area		0	9,057.29
6	Total Estimated Purchases		1,336,235	2,542,141.90
7				
8	Transportation Costs:			
9	Texas Gas Transmission			63,097.64
10	Tennessee Gas Pipeline			0.00
11	Trunkline Gas Area			0.00
11	ANR Pipeline Area			0.00
12				
13	Local Production		19,216	37,224.91
14				
15	WKG End-User Cash Outs		33,939	55,693.63
16				
17	Total Current Month Gas Cost		1,389,390	$2,698,158.08
18				
19	Less: Lost & Unaccounted for @	1.9%	26,398	
20				
21	Total Deliveries		1,362,992	$2,698,158.08
22				
23	Estimated LVS Weighted Average Commodity Rate			**$1.9796**

Western Kentucky Gas Company
Expected Purchases
LVS Commodity Purchase Basis
For Month of April, 1999

			(1)	(2)	(3)
Line No.			Mcf	MMbtu	Gas Cost
1	**Texas Gas Area**				
2	No Notice Service		1,785,574	1,830,213	3,377,841
3	Firm Transportation		252,195	258,500	473,856
4	Total Texas Gas Area		2,037,769	2,088,713	3,851,697
5					
6					
7	**Tennessee Gas Area**				
8	FT-A&G Commodity		298,200	310,128	601,742
9	FT-GS Commodity		73,825	76,778	194,502
10	Total Tennessee Gas Area		372,025	386,906	796,244
11					
12	**Trunkline Gas Area**				
13	Firm Transportation		72,464	75,000	135,504
14					
15					
16	**Local Production**				
17	Commodity		20,488	21,000	38,495
18					
19					
20	Expected WKG End-User Cash Outs		0	0	0
21					
22	**Total LVS Commodity Purchase Basis**		2,502,746	2,632,123	4,821,940
23					
24	Lost & Unaccounted for @	1.9%	47,552	50,010	
25					
26	Total Deliveries		2,455,194	2,582,113	4,821,940
27					
28	Estimated LVS Weighted Average Commodity Rate (per MMbtu)				$1.8674
29					
30	Estimated LVS Weighted Average Commodity Rate (per Mcf)				$1.9640
31	(To only be used to calculate commodity credit back on Exhibit B)				
32					
33					

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 102
Witness: Gary Smith

Data Request:

102. Refer to Mr. Smith's testimony on page 3, lines 3-13. Please provide the average margin per customer by customer class under present and proposed rates.

Response:

The requested information is summarized in the table below. The average annual margin includes distribution charges and monthly base charges.

	Average Margin per Customer	
	Present Rates	Proposed Rates
Residential Sales	$148.45	$206.63
Commercial Sales	$465.27	$632.63
Public Authority Sales	$1,140.84	$1,403.20
Industrial Sales & Transp.	$20,278.52	$22,791.57

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 103
Witness: Gary Smith

Data Request:

103. Refer to Mr. Smith's testimony on page 16, lines 1-2. Please define subsidy as that term is used by Mr. Smith.

Response:

The term "subsidy", in this context, refers to the state of general effectiveness of the Company's rate design among various customer classes. We consider that effective rate design balances several factors, such as incremental costs, embedded costs, and competitive market conditions.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 104
Witness: Gary Smith

Data Request:

104. Please explain the circumstances under which Western's discount policy would result in increasing a discount. What economic or other factors have to change in order for Western to agree to a higher discount?

Response:

Western's intent, when faced with the threat of industrial customer bypass, is to maximize the retention of revenues from the account - regardless of whether the customer is currently under a tariff rate or a negotiated discount rate.

Upon receipt of a request for a discount relating to a customer bypass threat, Western evaluates the customer's specific circumstances and responds accordingly. Each request is treated on a case-specific basis. The rate ultimately negotiated to retain the customer is a function of several factors, most notably the customer's valuation of Western's services.

The retention of a bypass-vulnerable customers is of value to Westerns ratepayers, as long as the negotiated rate exceeds the incremental cost of service to the customer.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 105
Witness: Gary Smith

Data Request:

105. Explain which of the circumstances requested in the immediately preceding question changed so that Western's response was to increase discounts by $800,000? (Mr. Smith's testimony, page 14, line 20.)

Response:

All of the factors listed the response to Item 104 applied to these cases.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 106
Witness: Gary Smith

Data Request:

106. Please explain the circumstances under which Western's discount policy would result in decreasing a discount.

Response:

As stated in the response to Item 104 of this Initial AG Data Request it is Western's intent, when faced with the threat of industrial customer bypass, to maximize the revenues from the account.

Entering into periods of contract re-negotiation, Western evaluates the customer's unique, case-specific circumstances and responds accordingly, including efforts to, perhaps, raise the rate to the customer. The rate ultimately negotiated to retain the customer is a function of several factors, most notably the customer's valuation of Western's services.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 107, a - f
Witness: Gary Smith

Data Request:

107. Refer to Mr. Smith's testimony at page 16, line 20.

a. Cite any reference material that supports Mr. Smith's statement.

b. Define margin component as that term is used by Mr. Smith. Please quantify, if possible.

c. Please provide the number of Western's special contract customers for which the referenced statement applies. As part of this response, please provide any numerical documentation of how gas costs represent a major component of the special contract customer's costs.

d. Indicate the impact of the $800,000 increased discount on the earned return of the affected customer operations in Kentucky.

e. Specifically, provide gas costs as a percent of total costs for each customer afforded a discount.

f. For each customer who received a portion of the $800,000 increased discount, what would the result have been of denying the discount?

Response:

a. Western references that several industries qualify for the Energy Direct Pay Authorization with the State of Kentucky Revenue Cabinet. To qualify for the sales tax provision pursuant to KRS 139.480(3), the cost of energy or energy-producing fuels must exceed three percent (3%) of the cost of production. Among Western 120 transportation customers, 29 customers participate in this arrangement. In Westerns opinion, this level of energy cost, and perhaps even lower ratios, constitute a major cost component of the manufacturing costs for these facilities.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 107, a - f
Witness: Gary Smith

b. I believe the questioner is referring to "major" component, as shown in testimony on the referenced line. The term "major component", in this context, is referring to a component of such significance as to warrant monitoring and controlling to the extent practical. It is difficult to quantify a universal threshold that would constitute a major component from industry to industry.

c. Each of the special contract customers considered the possibility of avoiding Westerns transportation charges worth their investigation. While Western cannot document the ratio of energy costs to overall production costs for these customers, we are aware that 9 of the 13 special contract customers have an Energy Direct Pay Authorization with the State Revenue Cabinet (see sub-part a. of this DR Item).

d. Western's gross profits are affected on a dollar-for-dollar basis. We have no way to determine the impact of the reduced transportation rate on the returns earned by the special contract customers.

e. Western cannot accurately determine this ratio, we do not know the total gas costs for the customer (since we primarily provide for transportation of the customers supply), and we do not know the total costs for the customer.

f. Western believes that each of the customers would have physically bypassed our service.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 108
Witness: Smith

Data Request:

(Reference Mr. Smith's testimony, page 17, line 15.) Please provide the tariff sheets applicable to the 13 referenced customers.

Response:

These are no tariff sheets applicable to these customers only. See Western's application, Volume 1, Tab 6 for a copy of the proposed tariff in this case.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 109
Witness: David H. Doggette

Data Request:

109. What is the pipe diameter size of the smallest mains that Western, as a practical matter, installs today?

Response:

As a practical matter, the smallest mains Western normally installs are of two-inch (2") nominal diameter.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 110
Witness: David H. Doggette

Data Request:

110. How many customers are served from mains of the size requested in the question immediately above?

Response:

Western Kentucky Gas does not maintain records in such a fashion to answer the question posed above.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 111
Witness: Smith

Data Request:

Reference Mr. Smith's testimony at page 20, lines 13-15. Cite any authoritative text that supports Mr. Smith's contention that prices that produce above average and below average returns on allocated embedded costs of service are uneconomic price signals.

Response:

Mr. Smith did not make the statement attributed to him above in this rate request. What Mr. Smith did say is that, "The cross-class subsidies inherent in our present rates send uneconomic signals to the market by undervaluing subsidized services and overvaluing those services used to provide a subsidy." He did not retrieve this statement from a text, but rather from the lessons learned through his daily experience in marketing gas services to all classes of customers.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 112, a - b
Witness: Gary Smith

Data Request:

112. Refer to Mr. Smith's testimony, pages 29-31. By way of illustrating your proposed Margin Loss Recovery Rider, assume the following for an industrial customer in a test year.

Deliveries	100,000 Mcf
Margin	15¢/Mcf

a. In a post-test year, assume deliveries to this customer are 80,000 Mcf and the margin had to be discounted to 10¢/Mcf to avoid bypass. Show the calculations producing the lost margins for this customer.

b. In a post-test year assume deliveries to this customer are 200,000 Mcf, and margin had to be discounted to 10¢/Mcf to avoid bypass. Show the calculations producing the lost margins for this customer.

Response:

The margin loss adjustment rider would be "triggered" by the change in the applicable special contract rate schedule to the above-referenced customer. The calculation of the loss would be driven primarily by the change in the rate, applied to the current level of annual usage.

a. The calculation of the lost margin in this case is as follows:

The change in the rate per Mcf -	$0.05
Times, the current annual usage, in Mcf-	x 80,000
Margin loss	$4,000

b. The calculation of the lost margin in this case is as follows:

The change in the rate per Mcf -	$0.05
Times, the current annual usage, in Mcf-	x 200,000
Margin loss	$10,000

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 113(a)
Witness: Thomas H. Petersen

Data Request:

Reference Mr. Peterson's testimony at page 4, lines 16-21.

a. Please provide the footage amount and cost amount of each of the six-inch and eight-inch mains additions that were excluded from your study.

Response:

a) As shown on footnote 1 of sheet 1, $3,189,471 of additions to 6 and 8 inch mains were reclassified from distribution to transmission for purposes of this study. These additions consisted of the following:

Year	Size	Feet	Cost
1998	6 inch	5,556	$160,191.92
1997	6 inch	34,261	$987,761.19
1996	6 inch	6,128	$234,782.36
1996	6 inch	9,632	$511,956.59
1995	6 inch	11,962	$395,464.44
1995	6 inch	7,182	$262,667.39
1998	8 inch	16,033	$636,646.85

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 113(b)
Witness: Thomas H. Petersen

Data Request:

Explain exactly how the inclusion of the cost per foot of the excluded 6- and 8- inch pipes would distort the distribution mains' regression analysis.

Response:

The analysis of the investment in mains by either the minimum system method or the regression minimum zero-intercept method of classifying costs between customer and demand categories assumes reasonably consistent operational and accounting procedures over long periods of time. Without such consistency the comparison of booked costs of different sized mains could be influenced more by operational and accounting changes than by underlying cost differences. In this case recent 6 and 8 inch additions were classified as distribution plant while earlier similar additions had been classified as transmission plant. Relatively small amounts of investment in 6 and 8 inch mains had been previously classified as distribution mains. Therefore, the recent additions increased the cost in 6 and 8 inch distribution mains by 56% to 82%. Since construction costs have increased over time the inclusion of recently constructed 6 and 8 inch mains without comparable older 6 and 8 inch mains would overstate the cost per foot of 6 and 8 inch mains relative to the embedded historic cost per foot of other sized mains.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 114(a)
Witness: Thomas H. Petersen

Data Request:

Reference Mr. Peterson's testimony, page 11, lines 3-14.

a. Did Mr. Peterson or Western investigate the use of the minimum system methodology for use in this proceeding? If no, why not.

Response:

a) We did not investigate the use of the minimum system method beyond the informational calculation shown on sheet 7 of the class cost of service study.

Please see also the answer to question 67.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 114(b)
Witness: Thomas H. Petersen

Data Request:

b. If the answer to a. is yes, please provide any assembled minimum system cost data, any calculations, and any results of any study of the minimum system methodology performed on the Western system.

Response:

b) Please see part a.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 115
Witness: Doggette

Data Request:

For the ten largest company construction projects to provide service to new customers (as opposed to construction projects related to maintenance) since 1995, please provide the information provided to managers responsible for the approval of such projects.

Response:

See response to AG DR Item 43.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 116
Witness: Thomas H. Petersen

<u>**Data Request:**</u>

Did Mr. Peterson or the Company investigate whether a curvilinear relationship between unit cost and pipe diameter produced a statistically better relationship than a linear relationship? If not, why not? If yes, please provide the study and its results.

<u>**Response:**</u>

Not specifically. We did visually inspect the universe of data shown on sheet 7 of the class cost of service study and compared the results of the analysis to prior analyses. Except for the data problem addressed in response to question 113, neither the inspection nor the comparisons indicated that the current regression analysis poorly described the cost relationship among the sizes of mains.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 117
Witness: Thomas H. Petersen

Data Request:

Please have Mr Peterson describe, based on his understanding of Western's operations and his understanding of local distribution company operations in general, the basic service that the Company provides to its end user sales and transportation customers.

Response:

Carriage service customers, rates T-3 and T-4, are provided interruptible and firm delivery service of customer owned gas supply with no customer rights to gas supply service from Western. Transportation service customers, rate T-2, are provided interruptible and firm delivery service of customer owned gas supply plus the right to purchase gas from Western at the applicable sales rate. Sales service customers, rates G-1 and G-2, are provided firm and interruptible sales service. These services are described in more detail in Western's tariffs.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 118
Witness: David H. Doggette

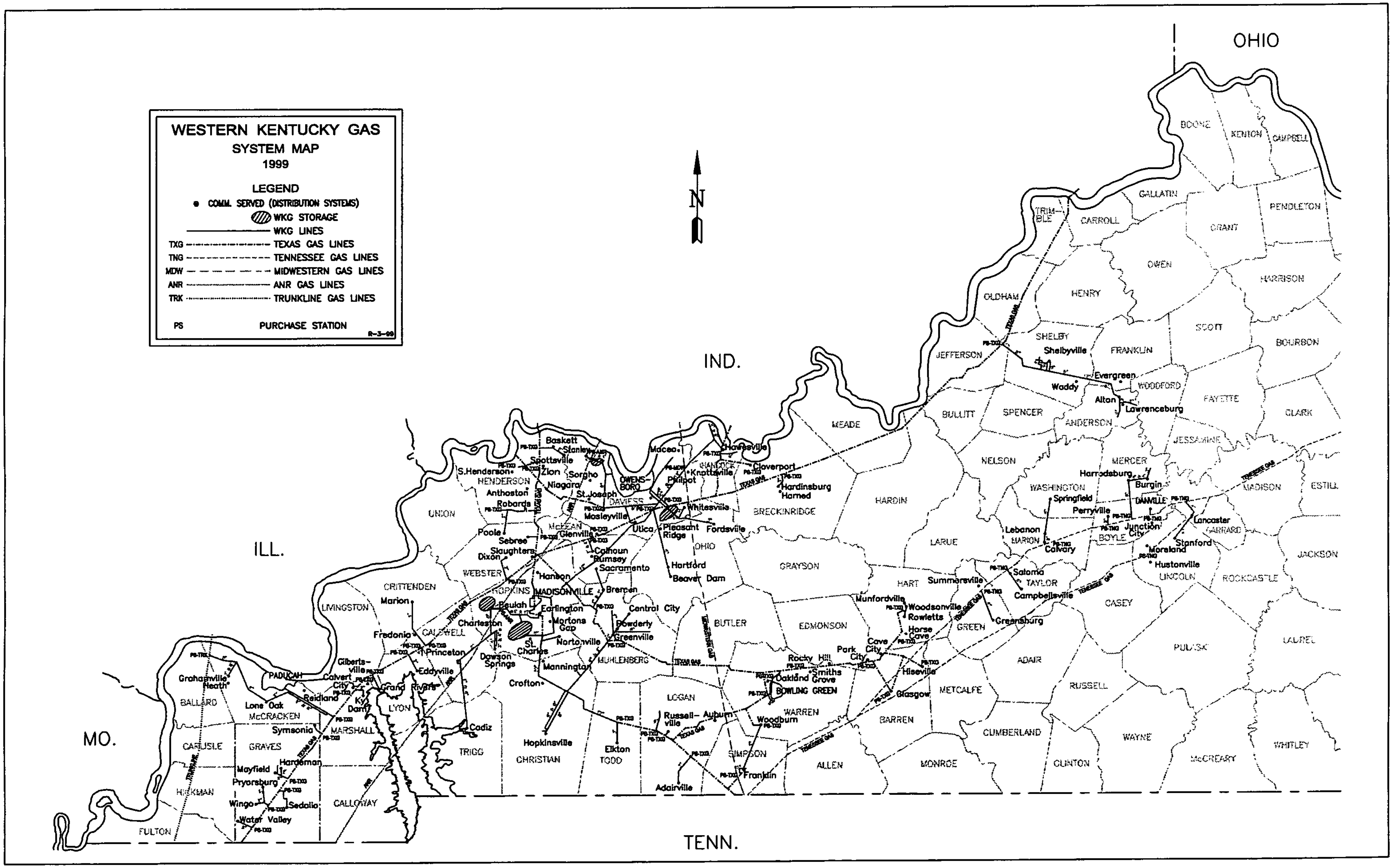
Data Request:

118. Please provide a map of the Western natural gas distribution system. Please annotate the map to locate pipeline interconnections, and any LNG or propane or other peak shaving facilities.

Response:

An 8 ½" x 11" copy of a map of the Western Kentucky Gas System, depicting the communities served by WKG distribution systems, the WKG transmission and high pressure distribution lines as well as the interstate pipelines and inter-connections is attached. One 24" x 36" color version of the map is also being provided to each party of record.

WKG peak shaving facilities are the gas storage fields shown on the map. WKG does not have any LNG or propane peak shaving plants on its system.


WESTERN KENTUCKY GAS
SYSTEM MAP
1999
LEGEND
COMM. SERVED (DISTRIBUTION SYSTEMS)
WKG STORAGE
WKG LINES
TXG TEXAS GAS LINES
TNG TENNESSEE GAS LINES
MDW MIDWESTERN GAS LINES
ANR ANR GAS LINES
TRK TRUNKLINE GAS LINES
PS PURCHASE STATION
R-3-99
N
OHIO
IND.
ILL.
MO.
TENN.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 119(a)
Witness: Thomas H. Petersen

Data Request:

a. Please provide a listing of all allocation factors and their numerical values.

Response:

a) Please see pages 16 and 17 of the class cost of service study.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 119(b)
Witness: Thomas H. Petersen

Data Request:

b. Separately for each demand factor, explain what each factor is (e.g., peak demand on design day excluding transmission customers, etc.) and how that factor differs from other demand allocation factors.

Response:

b) The four demand factors Design-A, Design-B, A&P and A&P/Gas are described on page 16 of the class cost of service study. Design-A is calculated using design day requirements assuming no curtailment. It is comparable to a non-coincident peak demand allocator. Design-B is calculated using design day requirements assuming curtailment of interruptible and carriage demands. A&P is calculated as a combination of Design-B and annual volumes, Vol A. A&P/Gas is calculated as a combination of Design-B and total sales volumes plus transportation volumes with sales stand-by rights, W/Gas.

Rb-Dem on page 17 is calculated using the demand allocations of rate base on page 5 of the study.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 119(c)
Witness: Thomas H. Petersen

Data Request:

c. Separately for each customer allocation factor, explain what each factor is and how that factor differs from other customer allocation factors.

Response:

c) The six customer factors are calculated on page 16 of the class cost of service study. Cust-A is calculated using the number of customers in each class. Cust-B weights the number of customers by multiplying Commercial customers by four and industrial customers by ten. Cust-C weights the number of customers by multiplying non-residential firm customers by 4, interruptible and carriage customers by 20 and large interruptible and carriage customers by 100. Cust-D is applied only to residential and commercial customers and uses the weightings developed from the meter investment analysis on sheets 8 and 9 of the study. Cust-E is calculated using the number of G-1 customers with daily contract demands of 240 mcf or greater plus interruptible and carriage customers. Large interruptible and carriage customers are mutliplies by 5 in the calculation. Cust-M is calculated using the weightings from the meter investment analysis on sheets 8 and 9 of the study and excluding large interruptible and carriage customers.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 120
Witness: Thomas H. Petersen

<u>Data Request</u>:

For each demand allocator, please state the basis for the amounts of interruptible customer demands included in the allocator. If the interruptible customer demands used to determine the demand allocators are less than the actual interruptible demands during recent peak demands, explain why the smaller demands have been used.

<u>**Response:**</u>

The allocator Design -A includes all the maximum daily contract demands for interruptible customers. The allocator Design-B does not include any interruptible demands. The allocator Design-B is intended to include firm design day requirements assuming curtailment of all interruptible and carriage volumes. The allocators A&P, A&P/Gas and Rb-Dem are derived from the other allocators. Please see also the response to 119(b).

Western Kentucky Gas Company

Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 121
Witness: Hack

Data Request:

Please identify the probability of design peak day occurrence for the Company's design peak day criteria. Include supporting work papers and documentation.

Response:

Western designs the peak day on a 5 degree F mean temperature for the Texas Gas Area and a 0 degree F mean temperature for the area served by Tennessee Gas. The area served by Texas Gas experienced a mean temperature of 5 degrees or less seven (7) times between the period of January, 1990 to April, 1998. The area served by Tennessee Gas experienced a mean temperature of 0 degrees or less three (3) times during the same period.

See Attachment - AG DR Item 121 for supporting documentation

WESTERN KENTUCKY GAS CO.
DEGREE DAY INFORMATION
FOR DANVILLE, KY (Tennessee Gas & Texas Gas Zone 4)
Days of 5 Deg. F Mean Temp or Less for
01/01/90 THRU 04/30/98

TOWN NAME	DATE	HIGH TEMP	LOW TEMP	MEAN TEMP	DEGREE DAYS	NORMAL DDAYS	LAST YR DDAYS
DANVILLE	1/18/94	-4	-20	-12	77	35	42
DANVILLE	2/28/96	0	-20	-10	75	27	27
DANVILLE	1/15/94	3	-7	-2	67	35	32
DANVILLE	2/3/96	10	-7	1.5	63	35	36
DANVILLE	2/4/96	12	-7	2.5	62	35	46
DANVILLE	1/19/94	5	3	4	61	34	27
DANVILLE	2/2/96	11	-3	4	61	36	34

WESTERN KENTUCKY GAS CO.
DEGREE DAY INFORMATION
FOR MADISONVILLE, KY (Texas Gas Zone 3)
Days of 5 Deg. F Mean Temp or Less for
01/01/90 THRU 04/30/98

TOWN NAME	DATE	HIGH TEMP	LOW TEMP	MEAN TEMP	DEGREE DAYS	NORMAL DDAYS	LAST YR DDAYS
MADISONVILLE	1/18/94	9	-20	-5.5	70	32	36
MADISONVILLE	2/3/96	8	-8	0	65	30	27
MADISONVILLE	2/28/96	10	-8	1	64	23	28
MADISONVILLE	2/4/96	8	-3	2.5	62	30	35
MADISONVILLE	1/19/94	10	-1	4.5	60	32	28

WESTERN KENTUCKY GAS CO.
DEGREE DAY INFORMATION
FOR PADUCAH, KY (Texas Gas Zone 2)
Days of 5 Deg. F Mean Temp or Less for
01/01/90 THRU 04/30/98

PADUCAH	2/28/96	0	-14	-7	72	24	29
PADUCAH	1/18/94	7	-14	-3.5	68	32	38
PADUCAH	1/19/94	12	-18	-3	68	32	30
PADUCAH	2/3/96	7	-3	2	63	31	24
PADUCAH	2/4/96	10	-3	3.5	61	31	37
PADUCAH	1/11/97	10	-3	3.5	61	33	30

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 122
Witness: Hack

Data Request:

Please provide a detailed supply and requirements schedule for the Company's three most recent annual peak days, including the 1996-97 winter season. The Schedules should include deliveries to meet demands by source (i.e., FTS, contract storage service, on-system storage, propane, etc., by pipeline rate schedule) and requirements by customer class. Separately identify deliveries and requirements for transportation customers. Also provide the Company's daily sendout sheet for each peak day and the applicable weather data.

Response:

See Attachment - AG DR Item 122

WESTERN KENTUCKY GAS COMPANY
PEAK DAY RECEIPTS

	Winter 96 - 97 January 13, 1997	Winter 97 - 98 March 11, 1998	Winter 98 - 99 January 4, 1999
Mean Temp	9 Deg. F	20 Deg. F	14 Deg. F
TEXAS GAS (NNS)			
Nominated System Supply	89,546	80,993	79,711
No Notice Service	45,102	49,466	57,294
TEXAS GAS (FT)			
Firm Transportation	16,524	16,401	2,903
COMPANY STORAGE	74,950	48,973	76,776
LOCALPRODUCTION	1,221	646	489
TRUNKLINE GAS PIPELINE	7,866	5,651	7,605
TENNESSEE GAS PIPELINE			
Nominated System Supply	18,254	6,473	19,216
No Notice Storage	18,312	24,990	22,775
TOTAL REQUIREMENTS *	**271,775**	**233,593**	**266,769**
THIRD PARTY TRANSPORTS	78,059	71,638	77,465
TOTAL THROUGH PUT	**349,834**	**305,231**	**344,234**

*** Daily Requirements by customer class are not available.**

Note: All volumes stated in MCF.

Western Kentucky Gas Company

Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 123
Witness: Hack

Data Request:

Please provide a summary identifying the salient features of each of the following currently in effect. Salient features include contract party, effective term and applicable contract entitlements (daily, annual, seasonal, etc.).

a. All firm transportation and no-notice agreements by type. Indicate whether the capacity is available at the Company's city gate to meet design day requirements or is upstream capacity. Identify the applicable downstream pipeline for each upstream arrangements.

b. All storage, gathering and exchange agreements. Indicate if each agreement provides design day capacity at the city gate or requires separate transportation (identify) service to effectuate delivery. Include any on-system storage and peak shaving facilities used by the Company.

c. Please reconcile the capacity entitlements identified in subparts a and b with the design day entitlements provided in response to the previous question.

Response:

a. See Attachment - AG DR Item 123(a)

b. Western owns five underground storage facilities that deliver gas quantities directly into WKG's distribution system. The storage deliverability varies with storage inventory. Storage deliverability during the time of an expected design day (January or February) is anticipated to range from 75,000 Mcf/day to 80,000 Mcf/day depending on operating conditions and storage field pressures.

c. See Attachment - AG DR Item 123 (c)

Western Kentucky Gas Company
Pipeline Contracts - FT AND NN

On 6/07/1999

PIPELINE	CONTRACT #	TERMINATION DATE	MDQ MMBTU	TYPE OF SERVICE	COMMENTS
Texas Gas Trans	NO210	10/31/01	45,500	NNS	Nom MDQ is 26,450 - Storage MDQ is 19,050
Texas Gas Trans	NO340	10/31/01	81,000	NNS	Nom MDQ is 64,717 - Storage MDQ is 16,283
Texas Gas Trans	NO435	10/31/01	13,500	NNS	Nom MDQ is 7,773 - Storage MDQ is 5,727
Texas Gas Trans	3355	10/31/01	15,000	FT	
Texas Gas Trans	3819	10/31/01	3,500	FT	
Texas Gas Trans	13687	10/31/01	12,500	FT	Only available Nov - Mar
MidWestern	24378	10/31/99	10,000	FT	
Tennessee Gas	2385	11/1/00	8,282	FT-GS	One part rate - Nom MDQ = 2,283 - Stor MDQ = 5,999
Tennessee Gas	2546	11/1/00	15,000	FT -G	Nom MDQ = 8,402 - Stor MDQ = 6,598
Tennessee Gas	2548	11/1/00	5,772	FT - G	Nom MDQ = 2,557 - Stor MDQ = 3,215
Tennessee Gas	2550	11/1/00	6,856	FT - G	Nom MDQ = 2,831 - Stor MDQ = 4,025
Tennessee Gas	2551	11/1/00	5,601	FT-G	Nom MDQ = 2,740 - Stor MDQ = 2,861
Tennessee Gas	2383	11/1/00	19,784	FS - (MA)	MSQ = 903,859 - MDQ Inj = 6,026 / Market Area Stor
Tennessee Gas	2384	11/1/00	2,914	FS - (PA)	MSQ = 409,679 - MDQ Inj = 2,731 / Prod Area Stor
Trunkline	14573	10/31/00	8,000	FTS	MDQ is 11,000 Eff 11/01/99

Note 1: All capacity is available at the Company's city gate to meet design day requirements.

Western Kentucky Gas Company
Capacity Entitlements vs Design Day

1998-1999 Pipeline	BTU Factor	Type Service	1/4/99 Receipts MCF	MDQ MMBTU	MDQ MCF
Texas Gas	1025	NNS-No Notice			
		Nominated	79,711	88,940	86,771
		Storage	57,294	41,060	40,059
Texas Gas	1025	FT	2,903	31,000	30,244
Trunkline[1]	1040	FTS	7,605	8,000	7,692
Tennessee Gas	1040	FS, FT-G, FT-GS			
		Nominated	19,216	18,813	18,089
		Storage	22,775	22,698	21,825
Midwestern	1025	FT	0	10,000	9,756
Company Storage	1000	Storage	76,776	77,000	77,000
Local Production	1000	Production	489	800	800
Total			266,769	298,311	292,236

1. Trunkline MDQ increases to 11,000 effective November 1, 1999

1997-1998 Pipeline	BTU Factor	Type Service	3/11/98 Receipts MCF	MDQ MMBTU	MDQ MCF
Texas Gas	1025	NNS-No Notice			
		Nominated	80,993	88,940	86,771
		Storage	49,466	41,060	40,059
Texas Gas	1025	FT	16,401	31,000	30,244
Trunkline[1]	1040	FTS	5,651	8,000	7,692
Tennessee Gas	1040	FS, FT-G, FT-GS			
		Nominated	6,473	18,813	18,089
		Storage	24,990	22,698	21,825
Midwestern	1025	FT	0	10,000	9,756
Company Storage	1000	Storage	48,973	77,000	77,000
Local Production	1000	Production	646	800	800
Total			233,593	298,311	292,236

1996-1997 Pipeline	BTU Factor	Type Service	1/13/97 Receipts MCF	MDQ MMBTU	MDQ MCF
Texas Gas	1025	NNS-No Notice			
		Nominated	89,546	88,940	86,771
		Storage	45,102	41,060	40,059
Texas Gas	1025	FT	16,524	31,000	30,244
Trunkline[1]	1040	FTS	7,866	8,000	7,692
Tennessee Gas	1040	FS, FT-G, FT-GS			
		Nominated	18,254	18,813	18,089
		Storage	18,312	22,698	21,825
Midwestern	1025	FT	0	10,000	9,756
Company Storage	1000	Storage	74,950	77,000	77,000
Local Production	1000	Production	1,221	800	800
Total			271,775	298,311	292,236

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 124
Witness: David H. Doggette

Data Request:

124. Please provide a detailed description of the Company's meter testing and change-out program.

Response:

Western has been using the testing and changeout periods as set forth in KAR 5:022 Section 8(5). For example, Western's current domestic meter testing and changeout program occurs on a ten (10) year cycle. During the tenth year since the last test, a service order is entered into the computer system for the meter to be removed. A Service Technician will remove the meter from service by cutting off the customer's gas, installing a meter, turning on the gas and relighting the customer's appliances.

The meter that was removed from service is returned to a meter shop. It is in-tested on a device, known as a bell prover, to verify its percent of accuracy against a known standard volume. If the meter is within 2% accuracy (98% to 100% registration), it is cleaned, refurbished and adjusted back to as nearly as possible to 100% registration (par) with ½% or less difference between "open" and "check" flow rates.

If a meter does not in-test within acceptable limits and is registering more than actual volume ("fast"), the account from which it came is noted and action is taken to issue a refund to the customer based on the difference between in-test registration of the meter and par. The meter shop usually remanufactures meters that test in this manner back to the specifications for new meters. In some instances a meter may be classified as obsolete or unrepairable and is junked.

Meters that have been refurbished, remanufactured, or purchased new are distributed throughout Western's operational area for use in new meter sets or for replacement of other meters being changed out.

As provided for in KAR 5:022 8(5)(c) and as approved by the Kentucky Public Service Commission, in case 99-059 Western will be transitioning to a statistical sampling program. Further information is provided in the response to Item 166 of this Initial Data Request.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item #125
Witness: Donald P. Burman

Data Request:

125. Please identify the bill preparation time required for each rate schedule/customer class reflected in the Company's cost of service study. Include copies of any analyses or studies conducted by the Company examining this issue.

Response:

The Company currently does not have any analyses or studies identifying the bill preparation time by customer class.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 126
Witness: David H. Doggette

Data Request:

126. For each rate schedule/customer class reflected in the Company's cost of service study, please:

a. identify the number of meters in service;

b. identify the number of times each month the meters of the various rate schedules/customer classes are physically read (i.e., daily, bi-monthly with estimated readings on alternating months); and

c. provide copies of any analyses or studies prepared by the Company examining meter reading time requirements by the various classes of customers served.

Response:

a. The average number of meters in service for the twelve month period ending September 30, 1998, was

Residential	Commercial	Industrial	Public Authority & Other	Total
155,846	18,035	426	1,585	175,892

b. Residential, commercial and non-transporting industrial meters are read monthly. Transporting industrial meters are electronically polled daily and a verification reading is performed on a monthly basis.

c. Western does not have an analyses or study examining meter reading time requirements by the various classes of customer served.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 127
Witness: Gruber

Data Request:

127. Please provide copies of any analyses, studies or documents which identify the frequency of billing inquiries by customer class and the time required to address those inquiries.

Response:

127. A listing of Western's billing inquiries and the time required to address those inquiries is attached in exhibit 1 for DR 127. This information is not available by customer class.

AG DR ITEM 127

WESTERN KENTUCKY GAS COMPANY

Billing Inquiries

Monthly Summary: August 1998-July 1999

Month	Calls		Avg Handle Time
Aug-98	8,308		4:09
Sep-98	7,761		4:25
Oct-98	9,925		4:03
Nov-98	8,350		4:01
Dec-98	9,736		3:42
Jan-99	14,680		3:49
Feb-99	14,951		4:02
Mar-99	15,591		3:53
Apr-99	13,079		3:47
May-99	10,651		3:55
Jun-99	9,411		6:17
Jul-99	6,633		5:41
Totals	**129,076**		**4:23**

EXIBIT 1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 128
Witness: Betty Adams

Data Request:

Please identify:

a. The O&M account in which costs associated with the Company's account representatives are reflected;
b. Total expenses associated with account representatives; and
c. The number of representatives servicing or assigned to each particular customer class.

Response:

a. The O&M accounts in which these costs are recorded are 909, 916 and 922.

b. The total expense associated with account representatives is $1.8 million. Included in this amount are costs associated with account representatives, managers and a vice-president.

c. All calls taken by the customer support associates are currently handled on an equal basis, so representatives are not assigned to a particular customer class. For the field account representatives, there are currently two that deal largely with industrial and large commercial customers.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 129
Witness: Gary Smith

Data Request:

129. Please provide actual and weather normalized sales volumes and number of customers by rate schedule for each month from January 1998 through that most recently available. Include supporting normalization workpapers and documentation.

Response:

Please reference the attached exhibit, Schedule AG DR No. 1, Item 129 for the requested information.

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Residential	Commercial	Industrial	Public Authority	Total	Transportation Customers
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Meters in Service						
2	(Source - Western Financial Statements)						
3							
4	Jan-98	156,181	18,087	399	1,593	176,260	80
5	Feb-98	156,212	18,110	395	1,596	176,313	103
6	Mar-98	156,039	18,105	393	1,594	176,131	96
7	Apr-98	155,683	18,065	390	1,591	175,729	87
8	May-98	155,642	18,043	390	1,583	175,658	112
9	Jun-98	155,949	18,050	246	1,582	175,827	112
10	Jul-98	155,830	18,011	245	1,577	175,663	112
11	Aug-98	155,899	17,999	241	1,578	175,717	118
12	Sep-98	156,107	18,000	442	1,579	176,128	101
13	Oct-98	156,688	18,100	445	1,575	176,808	98
14	Nov-98	157,309	18,220	445	1,575	177,549	114
15	Dec-98	157,779	18,298	443	1,578	178,098	114
16	Jan-99	158,019	18,353	441	1,578	178,391	114
17	Feb-99	158,209	18,372	439	1,575	178,595	108
18	Mar-99	158,337	18,369	437	1,572	178,715	108
19	Apr-99	158,306	18,352	436	1,570	178,664	108
20	May-99	158,372	18,346	435	1,562	178,715	108

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Residential	Commercial	Industrial	Public Authority	Unbilled	Total Sales	Transportation Customers	Total Deliveries
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)
1	Volumes Sold & Transported								
2	(Source - Western Financial Statements)								
3									
4	Jan-98	2,258,955	936,383	602,692	281,751	194,130	4,273,911	2,953,397	7,227,308
5	Feb-98	2,090,355	844,082	303,540	218,137	(543,737)	2,912,377	1,558,663	4,471,040
6	Mar-98	1,796,088	707,894	166,264	200,949	(183,079)	2,688,116	2,412,765	5,100,881
7	Apr-98	1,242,724	512,256	257,339	136,243	(1,070,043)	1,078,519	2,263,480	3,341,999
8	May-98	642,818	312,737	149,240	71,681	(125,966)	1,050,510	2,068,871	3,119,381
9	Jun-98	290,969	207,389	170,503	39,929	(23,381)	685,409	2,068,824	2,754,233
10	Jul-98	250,082	170,169	213,789	30,069	(36,622)	627,487	1,900,787	2,528,274
11	Aug-98	223,798	147,486	110,091	38,169	34,424	553,968	1,953,276	2,507,244
12	Sep-98	240,513	185,124	210,412	30,588	62,908	729,545	2,074,297	2,803,842
13	Oct-98	261,719	192,508	288,757	46,360	212,557	1,001,901	2,207,122	3,209,023
14	Nov-98	749,443	322,448	375,258	95,342	449,641	1,992,132	2,172,680	4,164,812
15	Dec-98	1,290,062	495,867	318,422	140,657	878,630	3,123,638	2,306,776	5,430,414
16	Jan-99	2,701,698	1,103,859	273,511	299,755	(462,476)	3,916,347	2,597,469	6,513,816
17	Feb-99	1,877,477	744,620	297,309	203,258	(325,702)	2,796,962	2,124,347	4,921,309
18	Mar-99	1,974,343	792,996	380,097	221,692	(99,641)	3,269,487	2,484,002	5,753,489
19	Apr-99	1,340,638	396,434	149,526	101,589	(668,482)	1,319,705	2,017,637	3,337,342
20	May-99	531,742	369,602	173,638	100,965	(145,237)	1,030,710	1,991,296	3,022,006

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Residential	Commercial	Industrial	Public Authority	Unbilled	Total Sales	Transportatio Customers	Total Deliveries
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Volumes Sold & Transported - Weather Adjusted								
2	(Source - Western Financial Statements)								
3									
4	Jan-98 [1]	2,496,680	1,062,037	602,692	290,153	194,130	4,645,692	2,953,397	7,599,089
5	Feb-98 [1]	2,416,951	980,849	303,540	270,701	(543,737)	3,428,303	1,558,663	4,986,966
6	Mar-98 [1]	1,874,408	773,586	166,264	208,943	(183,079)	2,840,122	2,412,765	5,252,887
7	Apr-98 [1]	1,206,884	555,078	257,339	138,726	(1,070,043)	1,087,985	2,263,480	3,351,465
8	May-98 [1]	646,506	346,091	149,240	78,869	(125,966)	1,094,739	2,068,871	3,163,610
9	Jun-98 [1]	350,587	178,045	170,503	46,814	(23,381)	722,568	2,068,824	2,791,392
10	Jul-98 [1]	238,438	204,144	213,789	25,121	(36,622)	644,870	1,900,787	2,545,657
11	Aug-98 [1]	236,624	113,953	110,091	43,243	34,424	538,336	1,953,276	2,491,612
12	Sep-98 [2]	269,565	174,251	210,412	39,217	62,908	756,353	2,074,297	2,830,650
13	Oct-98 [2]	545,336	257,648	288,757	68,381	212,557	1,372,679	2,207,122	3,579,801
14	Nov-98 [2]	1,128,696	481,827	375,258	132,158	449,641	2,567,579	2,172,680	4,740,259
15	Dec-98 [2]	1,876,945	725,833	318,422	194,494	878,630	3,994,324	2,306,776	6,301,100
16	Jan-99 [2]	2,474,554	998,927	273,511	278,804	(462,476)	3,563,320	2,597,469	6,160,789
17	Feb-99 [2]	2,401,860	940,717	297,309	255,282	(325,702)	3,569,466	2,124,347	5,693,813
18	Mar-99 [2]	1,859,557	755,741	380,097	203,188	(99,641)	3,098,942	2,484,002	5,582,944
19	Apr-99 [2]	1,198,621	394,180	149,526	99,039	(668,482)	1,172,884	2,017,637	3,190,521
20	May-99 [2]	644,671	438,395	173,638	119,407	(145,237)	1,230,875	1,991,296	3,222,171
21									

22 Notes: [1] - Volume adjusted for weather normalization by adding volumes for corresponing months from Sheet 2 of 11 of this Exhibit for each class plus corresponding month weather adjustment (column j) on Sheet in this Exhibit as follows: Sheet 4 of 11 - Residential, Sheet 5 of 11 - Commercial, Sheet 6 of 11 - Public Authority.

[2] - Volume adjusted for weather normalization by adding volumes for corresponing months from Sheet 2 of 11 of this Exhibit for each class plus corresponding month weather adjustment (column j) on Sheet in this Exhibit as follows: Sheet 8 of 11 - Residential, Sheet 9 of 11 - Commercial, Sheet 10 of 11 - Public Authority.

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Lagged Normal Ddays [1]	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Residential - Class 1 Rate 1									
1	Sep-97	14.5	0.0154	0.2240	1.5444	1.7684	149,685	264,706	251,199	13,507
2	Oct-97	134.0	0.0154	2.0702	1.5444	3.6146	150,484	543,943	325,214	218,729
3	Nov-97	379.5	0.0154	5.8630	1.5444	7.4074	153,862	1,139,721	1,179,797	(40,076)
4	Dec-97	689.5	0.0154	10.6522	1.5444	12.1966	155,921	1,901,709	2,019,864	(118,155)
5	Jan-98	933.0	0.0154	14.4141	1.5444	15.9585	156,448	2,496,679	2,258,954	237,725
6	Feb-98	900.0	0.0154	13.9043	1.5444	15.4487	156,450	2,416,952	2,090,356	326,596
7	Mar-98	673.0	0.0154	10.3973	1.5444	11.9417	156,963	1,874,408	1,796,088	78,320
8	Apr-98	399.5	0.0154	6.1720	1.5444	7.7164	156,414	1,206,956	1,242,796	(35,840)
9	May-98	169.5	0.0154	2.6186	1.5444	4.1630	155,280	646,434	642,746	3,688
10	Jun-98	47.0	0.0154	0.7261	1.5444	2.2705	154,408	350,587	290,969	59,618
11	Jul-98	0.5	0.0154	0.0077	1.5444	1.5521	153,621	238,438	250,082	(11,644)
12	Aug-98	0.0	0.0154	0.0000	1.5444	1.5444	153,212	236,624	223,798	12,826
13										
14	Total	4,340.0			1.5444		154,396	13,317,157	12,571,863	745,294
15										
16	Average Usage / Customer							86.25	81.43	
17										
18	Note: [1] - Refer to Sheet 7 of 11 of this Exhibit.									

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Lagged Normal Ddays [1]	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Commercial - Class 2 Rate 1									
1	Sep-97	14.5	0.05106	0.7404	7.7028	8.4432	16,752	141,440	165,944	(24,504)
2	Oct-97	134.0	0.05106	6.8423	7.7028	14.5451	16,851	245,100	238,606	6,494
3	Nov-97	379.5	0.05106	19.3780	7.7028	27.0808	17,419	471,721	488,372	(16,651)
4	Dec-97	689.5	0.05106	35.2072	7.7028	42.9100	17,783	763,069	819,634	(56,565)
5	Jan-98	933.0	0.05106	47.6407	7.7028	55.3435	17,846	987,661	862,007	125,654
6	Feb-98	900.0	0.05106	45.9557	7.7028	53.6585	17,444	936,019	799,253	136,767
7	Mar-98	673.0	0.05106	34.3646	7.7028	42.0674	17,948	755,026	689,334	65,692
8	Apr-98	399.5	0.05106	20.3992	7.7028	28.1020	17,900	503,026	460,204	42,822
9	May-98	169.5	0.05106	8.6550	7.7028	16.3578	17,723	289,910	256,557	33,354
10	Jun-98	47.0	0.05106	2.3999	7.7028	10.1027	17,480	176,596	205,941	(29,345)
11	Jul-98	0.5	0.05106	0.0255	7.7028	7.7283	17,330	133,932	99,957	33,975
12	Aug-98	0.0	0.05106	0.0000	7.7028	7.7028	17,179	132,327	165,860	(33,533)
13										
14	Total	4,340			7.7028		17,471	5,535,827	5,251,667	284,161
15										
16	Average Usage / Customer							316.9	300.6	
17										
18	Note: [1] - Refer to Sheet 7 of 11 of this Exhibit.									

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Lagged Normal Ddays [1]	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Public Authority - Class 4 Rate 1									
1	Sep-97	14.5	0.16224	2.3525	21.1039	23.4564	1,556	36,497	37,564	(1,067)
2	Oct-97	134.0	0.16224	21.7400	21.1039	42.8439	1,569	67,222	48,093	19,129
3	Nov-97	379.5	0.16224	61.5696	21.1039	82.6735	1,566	129,467	133,390	(3,923)
4	Dec-97	689.5	0.16224	111.8636	21.1039	132.9675	1,576	209,557	229,697	(20,140)
5	Jan-98	933.0	0.16224	151.3688	21.1039	172.4727	1,576	271,817	263,415	8,402
6	Feb-98	900.0	0.16224	146.0149	21.1039	167.1188	1,570	262,377	209,813	52,564
7	Mar-98	673.0	0.16224	109.1867	21.1039	130.2906	1,589	207,032	199,038	7,994
8	Apr-98	399.5	0.16224	64.8144	21.1039	85.9183	1,586	136,266	133,783	2,483
9	May-98	169.5	0.16224	27.4995	21.1039	48.6034	1,585	77,036	69,848	7,188
10	Jun-98	47.0	0.16224	7.6252	21.1039	28.7291	1,575	45,248	38,363	6,885
11	Jul-98	0.5	0.16224	0.0811	21.1039	21.1850	1,559	33,027	37,975	(4,948)
12	Aug-98	0.0	0.16224	0.0000	21.1039	21.1039	1,559	32,901	27,827	5,074
13										
14	Total	4,340			21.1039		1,572	1,508,447	1,428,806	79,641
15										
16	Average Usage / Customer							959.5	908.8	
17										
18	Note: [1] - Refer to Sheet 7 of 11 of this Exhibit.									

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Actual Ddays	Normal Ddays	Lagged Actual 50% Prior Mo. DDays	Lagged Normal 50% Prior Mo. DDays
	(a)	(b)	(c)	(d)	(e)
1	Aug-97	0	0		
2	Sep-97	18	29	9.0	14.5
3	Oct-97	284	239	151.0	134.0
4	Nov-97	658	520	471.0	379.5
5	Dec-97	864	859	761.0	689.5
6	Jan-98	728	1,007	796.0	933.0
7	Feb-98	594	793	661.0	900.0
8	Mar-98	573	553	583.5	673.0
9	Apr-98	267	246	420.0	399.5
10	May-98	29	93	148.0	169.5
11	Jun-98	13	1	21.0	47.0
12	Jul-98	0	0	6.5	0.5
13	Aug-98	0	0	0.0	0.0
14					
15		4,028	4,340	4,028.0	4,340.0

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Lagged Normal Ddays [1]	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Residential - Class 1 Rate 1									
1	Jun-98	47.0	0.0151	0.7098	1.5444	2.2542	154,408	348,070	290,969	57,101
2	Jul-98	0.5	0.0151	0.0076	1.5444	1.5520	153,621	238,423	250,082	(11,659)
3	Aug-98	0.0	0.0151	0.0000	1.5444	1.5444	153,212	236,624	223,798	12,826
4	Sep-98	14.5	0.0151	0.2190	1.5444	1.7634	152,865	269,565	240,513	29,052
5	Oct-98	134.0	0.0151	2.0236	1.5444	3.5680	152,840	545,336	261,719	283,617
6	Nov-98	379.5	0.0151	5.7312	1.5444	7.2756	155,134	1,128,696	749,443	379,253
7	Dec-98	689.5	0.0151	10.4127	1.5444	11.9571	156,973	1,876,945	1,290,062	586,883
8	Jan-99	933.0	0.0151	14.0900	1.5444	15.6344	158,276	2,474,554	2,701,698	(227,144)
9	Feb-99	900.0	0.0151	13.5917	1.5444	15.1361	158,684	2,401,860	1,877,477	524,383
10	Mar-99	673.0	0.0151	10.1635	1.5444	11.7079	158,829	1,859,557	1,974,343	(114,786)
11	Apr-99	399.5	0.0151	6.0332	1.5444	7.5776	158,179	1,198,621	1,340,638	(142,017)
12	May-99	169.5	0.0151	2.5598	1.5444	4.1042	157,075	644,671	531,742	112,929
13										
14	Total	4,340			1.5444		155,841	13,222,922	11,732,483	1,490,438
15										
16	Average Usage / Customer							84.85	75.28	
17										
18	Note: [1] - Refer to Sheet 11 of 11 of this Exhibit.									

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Lagged Normal Ddays [1]	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Commercial - Class 2 Rate 1									
1	Jun-98	47.0	0.04729	2.2225	7.7028	9.9253	17,480	173,494	205,941	(32,447)
2	Jul-98	0.5	0.04729	0.0236	7.7028	7.7264	17,330	133,899	99,957	33,942
3	Aug-98	0.0	0.04729	0.0000	7.7028	7.7028	17,179	132,327	165,860	(33,533)
4	Sep-98	14.5	0.04729	0.6857	7.7028	8.3885	17,128	143,679	154,553	(10,874)
5	Oct-98	134.0	0.04729	6.3365	7.7028	14.0393	17,112	240,241	175,101	65,140
6	Nov-98	379.5	0.04729	17.9455	7.7028	25.6483	17,549	450,102	290,723	159,379
7	Dec-98	689.5	0.04729	32.6045	7.7028	40.3073	17,821	718,317	488,351	229,966
8	Jan-99	933.0	0.04729	44.1189	7.7028	51.8217	18,040	934,864	1,039,796	(104,932)
9	Feb-99	900.0	0.04729	42.5585	7.7028	50.2613	18,116	910,534	714,437	196,097
10	Mar-99	673.0	0.04729	31.8243	7.7028	39.5271	18,109	715,797	753,052	(37,255)
11	Apr-99	399.5	0.04729	18.8912	7.7028	26.5940	18,058	480,235	482,489	(2,254)
12	May-99	169.5	0.04729	8.0152	7.7028	15.7180	17,887	281,148	212,355	68,793
13										
14	Total	4,340			7.7028		17,651	5,314,637	4,782,614	532,023
15										
16	Average Usage / Customer							301.10	270.96	
17										
18	Note: [1] - Refer to Sheet 11 of 11 of this Exhibit.									

Western Kentucky Gas Company
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Lagged Normal Ddays [1]	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Public Authority - Class 4 Rate 1									
1	Jun-98	47.0	0.15768	7.4107	21.1039	28.5146	1,575	44,910	38,363	6,547
2	Jul-98	0.5	0.15768	0.0788	21.1039	21.1827	1,559	33,024	37,975	(4,951)
3	Aug-98	0.0	0.15768	0.0000	21.1039	21.1039	1,559	32,901	27,827	5,074
4	Sep-98	14.5	0.15768	2.2863	21.1039	23.3902	1,559	36,465	27,836	8,629
5	Oct-98	134.0	0.15768	21.1285	21.1039	42.2324	1,558	65,798	43,777	22,021
6	Nov-98	379.5	0.15768	59.8378	21.1039	80.9417	1,563	126,512	89,697	36,816
7	Dec-98	689.5	0.15768	108.7171	21.1039	129.8210	1,568	203,559	149,722	53,837
8	Jan-99	933.0	0.15768	147.1111	21.1039	168.2150	1,570	264,098	285,049	(20,951)
9	Feb-99	900.0	0.15768	141.9078	21.1039	163.0117	1,570	255,928	203,904	52,024
10	Mar-99	673.0	0.15768	106.1155	21.1039	127.2194	1,571	199,862	218,366	(18,504)
11	Apr-99	399.5	0.15768	62.9913	21.1039	84.0952	1,568	131,861	134,411	(2,550)
12	May-99	169.5	0.15768	26.7260	21.1039	47.8299	1,565	74,854	56,412	18,442
13										
14	Total	4,340			21.1039		1,565	1,469,772	1,313,338	156,434
15										
16	Average Usage / Customer							938.90	838.97	
17										
18	Note: [1] - Refer to Sheet 11 of 11 of this Exhibit.									

Western Kentucky Gas
AG Data Request #1, Dated August 19, 1999
Item 129

Line No.	Month	Actual Ddays	Normal Ddays	Lagged Actual 50% Prior Mo. DDays	Lagged Normal 50% Prior Mo. DDays
	(a)	(b)	(c)	(d)	(e)
1	May-98	29	93		
2	Jun-98	13	1	21.0	47.0
3	Jul-98	0	0	6.5	0.5
4	Aug-98	0	0	0.0	0.0
5	Sep-98	3	29	1.5	14.5
6	Oct-98	164	239	83.5	134.0
7	Nov-98	445	520	304.5	379.5
8	Dec-98	752	859	598.5	689.5
9	Jan-99	835	1,007	793.5	933.0
10	Feb-99	605	793	720.0	900.0
11	Mar-99	675	553	640.0	673.0
12	Apr-99	184	246	429.5	399.5
13	May-99	31	93	107.5	169.5
14					
15		3,707	4,340	3,706	4,340

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 130
Witness: Gary Smith

Data Request:

130. Please provide actual and weather normalized transportation volumes and number of customers by rate schedule for each month from January 1998 through that most recently available. Include supporting normalization workpapers and documentation.

Response:

The requested information is included in the attachment to Item 129 of this, the First AG Data Request dated August 19, 1999. Transportation volumes are not subject to weather normalization adjustments.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 131
Witness: Hack

Data Request:

Please provide copies of any studies conducted by the Company which examine the effect of transportation customer imbalances on system sales customers' gas costs.

Response:

No studies have been performed.

Western Kentucky Gas Company

Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 132
Witness: Hack

Data Request:

Please provide a schedule separately identifying all interruptions of transportation or retail sales service on the Western system since 1994 due to capacity constraints on Western's distribution system. Identify the length of interruption, the volumes interrupted, the rate schedule of the interrupted customers, and the area in which interruptions occurred if the interruption was local rather than general on the Western system.

Response:

Our records reflect only one interruption due to constraints on the Western system since 1994. This was a localized interruption in the Texas Gas zone 4 area due to system low pressure. Customers interrupted consisted of the following rate schedules: one interruptible commercial customer; three T-3 transportation customers; and one T-4 transportation customer. These customers were interrupted for approximately 4 hours and the volume interrupted is unknown. This response does not include curtailments of interruptible customers to stay within pipeline contractual MDQs.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 133
Witness: Hack

Data Request:

Please explain how often most of Western's transportation customers generally revise their nominations for deliveries into Western's system by class. Hourly, daily, monthly?

Response:

All transportation customers submit a monthly nomination reflecting their daily nominated quantities. During the month transportation customers may change nominations daily and also make intra-day nominations. It is very common for transportation customers to change nominations frequently during the month (i.e. receipt point changes, volume changes, etc.).

Western Kentucky Gas Company

Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 134
Witness: Hack

Data Request:

Please identify the monthly quantity of Standby service reserved by transportation customers during the period January 1996 to present.

Response:

Western's transportation tariffs do not provide for quantities of reserved standby service for its transportation customers. However, customers transporting on the T-2 Transportation Rate reflects the customer's service for their respective sales rate.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 135
Witness: Thomas H. Petersen

Data Request:

Please provide all workpapers, calculations, documentation and studies relied upon or utilized to develop each allocation factor reflected in the Company's cost of service study. Include copies of all computer files on Lotus 1-2-3, Quattro or Excel format.

Response:

The allocators in the class cost of service study are calculated on pages 16 and 17 of the study. The data for most of the allocators is drawn from elsewhere in the study. Winter period volumes were taken from the same data as the bill frequency on page 18 of the study. The Design-A and Design-b allocators are based on design day data. My design day workpaper is attached.

An Excel copy of this workpaper is attached. See also the response to item 136.

Design Day Estimates
1997 - 1998
@ 14.73 psia

	Residential	Commercial	Industrial	Combo		Big combo		Sub-Total	L&U	Total
				Firm	Inter.	Firm	Inter.			
Zone 2	30,596	16,682	757	401	12,884	43	25,469	86,832	1,758	88,590
Zone 3	109,187	54,420	8,129					171,736		
Bowling Green			240	-	5,830	50	2,030	8,150		
Franklin				100	940	1,200	-	2,240		
Glascow				767	1,758		1,700	4,225		
Russellville			10	-	1,985		9,660	11,655		
Hopkinsville				3	3,591		3,750	7,344		
Owensboro			250	10	7,123	10	38,905	46,298		
Greenville				-	950		-	950		
Madisonville				-	1,650	300	5,300	7,250		
Princeton	0	0	0	100	1,630	0	0	1,730		
Total	109,187	54,420	8,629	980	25,457	1,560	61,345	261,578	6,342	267,920
Zone 4	9,259	4,621	2,635	-	3,537	-	4,200	24,252	688	24,940
Danville	7,208	4,399	520	-	2,260	-	4,350	18,737	443	19,180
Harrodsburg	3,649	2,334	256	3	2,550	-	-	8,792	227	9,019
Lebanon	3,272	2,870	696	-	1,510	-	-	8,348	252	8,600
Campbellsville	4,535	2,322	331	100	1,300	-	-	8,588	261	8,849
Greensburg et al	4,711	2,224	293	-	-	-	-	7,228	262	7,490
Total	172,417	89,872	14,117	1,484	49,498	1,603	95,364	424,355	10,233	434,588
Zone 2	31,215	17,020	772	409	13,145	44	25,985	88,590	included	88,590
Zone 3	111,834	55,739	8,838	1,004	26,074	1,598	62,832	267,919	included	267,919
Zone 4	9,522	4,752	2,710	-	3,637	-	4,319	24,940	included	24,940
Danville	7,378	4,503	532	-	2,313	-	4,453	19,179	included	19,179
Harrodsburg	3,743	2,394	263	3	2,616	-	-	9,019	included	9,019
Lebanon	3,371	2,957	717	-	1,556	-	-	8,601	included	8,601
Campbellsville	4,673	2,393	341	103	1,340	-	-	8,850	included	8,850
Greensburg et al	4,882	2,305	304	-	-	-	-	7,491	included	7,491
Total	176,618	92,063	14,477	1,519	50,681	1,642	97,589	434,589	included	434,589
Post estimate contract additions						900	1,100			
Total						2,542	98,689			

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 136
Witness: Petersen

Data Request:

Please provide a copy of the Company's cost of service study on computer diskette in Lotus 1-2-3, Quattro or Excel format.

Response:

Western provided this diskette to the KPSC Staff and Attorney General on July 23, 1999 by letter from Mr. Hutchinson to Ms. Mitchell and Mr. Spenard in response to a request from Ms. Mitchell dated July 15, 1999.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 137
Witness: Gary Smith

Data Request:

137. Please provide copies of all studies and analyses prepared by the Company which examine usage per customer for new homes and converting customers, and the usage per customer for new homes and converting customers with that of present customers.

Response:

Attached hereto, as Schedule AG DR No. 1, Item 137, is a preliminary analysis conducted by the Company, examining the usage per customer for recent residential additions.

The study utilized marketing reports to identify the account numbers for customers added. The marketing reports varied in their completeness; reports do not include account numbers for residential new construction additions other than those utilizing both heating and water heating, and reports for fiscal year 1996 did not include customer account numbers for any addition. Therefore, we randomly selected a number of customers for whom accounts were available, from the reported additions during fiscal year 1995 and 1997.

Actual usage for customers in the sample group were captured, and usage patterns for the group were analyzed - calculating the base load, heating load and weather normalizing the actual usage during fiscal year 1998.

Sheets 1-5 of the attached schedule provide the workpapers from Western's preliminary analysis, which concluded that recent residential customer additions average 76 Mcf per year versus Western's total residential customer average of 86 Mcf per year, weather normalized.

Western Kentucky Gas Company
Normalization Of Volumes For Weather
Reference Period Ended September 30, 1998
Estimated Requirements for Residential Customer Additions

Line No.	Category of Residential Service	Appliance Percentages (Sheet 5)	% of New Market Additions (Sheet 5)	X Coefficient	Constant	Actual Usage per Customer	Normalized Usage per Customer		Reference
	(a)	(b)	(c)	(d)	(e)	(f)	(g)		(g)
1	Total WKG Customer Base			0.0155	1.5444	81.22	86.15		Exhibit GLS- 4
2									
3	Residential New Construction Additions-								
4	- New Constr. W/ Htg & WH	82.7%		0.0153	1.6971	82.02	86.80		Sheet 2
5	- New Constr. W/ Htg Only	17.1%		0.0153		61.65	66.43	E	X - Sheet 2
6	- New Constr. W/ WH Only	0.3%			1.6971	20.36	20.36	E	Const.-Sheet 2
7	TOTAL New Residential Construction		66.9%	0.0153	1.4071	78.38	83.16		
8									
9	Residential Conversion Additions-								
10	- Conversions W/ Htg & WH	15.9%		0.0145	1.1579	72.23	76.75		Sheet 3
11	- Conversions W/ Htg Only	77.6%		0.0144		58.11	62.60		Sheet 4
12	- Conversions W/ WH Only	6.6%			1.1579		13.89	E	Const.-Sheet 3
13	TOTAL Residential Conversions		33.1%	0.0135	0.2599	56.53	61.65		
14									
15	TOTAL RESIDENTIAL ADDITIONS			0.0147	1.0279	71.16	76.05		
16									
17									
18	E - Estimate based on factor from referenced Sheet.								

Western Kentucky Gas Company
Normalization Of Volumes For Weather
Reference Period Ended September 30, 1998
New Construction - Heating and Water Heating

Line No.	Month	Lagged Normal DDays	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers In Sample	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Residential - Class 1 Rate 1									
1	Oct-97	29.0	0.0153	0.4439	1.6971	2.1410	51	109	117	(8)
2	Nov-97	239.0	0.0153	3.6580	1.6971	5.3551	51	273	428	(155)
3	Dec-97	520.0	0.0153	7.9589	1.6971	9.6560	51	492	686	(194)
4	Jan-98	859.0	0.0153	13.1475	1.6971	14.8446	51	757	753	4
5	Feb-98	1,007.0	0.0153	15.4127	1.6971	17.1098	51	873	696	178
6	Mar-98	793.0	0.0153	12.1373	1.6971	13.8344	51	706	577	129
7	Apr-98	553.0	0.0153	8.4640	1.6971	10.1611	51	518	371	147
8	May-98	246.0	0.0153	3.7652	1.6971	5.4623	51	279	194	85
9	Jun-98	93.0	0.0153	1.4234	1.6971	3.1205	51	159	105	54
10	Jul-98	1.0	0.0153	0.0153	1.6971	1.7124	51	87	90	(3)
11	Aug-98	0.0	0.0153	0.0000	1.6971	1.6971	51	87	83	4
12	Sep-98	0.0	0.0153	0.0000	1.6971	1.6971	51	87	83	4
13										
14	Total	4,340			1.6971		51	4,427	4,183	245
15	Average Usage / Customer							86.80	82.02	

Western Kentucky Gas Company
Normalization Of Volumes For Weather
Reference Period Ended September 30, 1998
Conversions - Heating and Water Heating

Line No.	Month	Lagged Normal DDays	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers In Sample	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Residential - Class 1 Rate 1									
1	Oct-97	29.0	0.0145	0.4200	1.1579	1.5779	19	29.98	26.4	3.58
2	Nov-97	239.0	0.0145	3.4614	1.1579	4.6193	19	87.77	141.6	(53.83)
3	Dec-97	520.0	0.0145	7.5311	1.1579	8.6890	19	165.09	230.5	(65.41)
4	Jan-98	859.0	0.0145	12.4408	1.1579	13.5987	19	258.38	253.7	4.68
5	Feb-98	1,007.0	0.0145	14.5842	1.1579	15.7421	19	299.10	234.7	64.40
6	Mar-98	793.0	0.0145	11.4849	1.1579	12.6428	19	240.21	195.2	45.01
7	Apr-98	553.0	0.0145	8.0090	1.1579	9.1669	19	174.17	135.7	38.47
8	May-98	246.0	0.0145	3.5628	1.1579	4.7207	19	89.69	63.9	25.79
9	Jun-98	93.0	0.0145	1.3469	1.1579	2.5048	19	47.59	26.9	20.69
10	Jul-98	1.0	0.0145	0.0145	1.1579	1.1724	19	22.28	25.7	(3.42)
11	Aug-98	0.0	0.0145	0.0000	1.1579	1.1579	19	22.00	18.3	3.70
12	Sep-98	0.0	0.0145	0.0000	1.1579	1.1579	19	22.00	19.8	2.20
13										
14	Total	4,340			1.1579		19	1,458.26	1,372.40	85.86
15	Average Usage / Customer							76.75	72.23	

Western Kentucky Gas Company
Normalization Of Volumes For Weather
Reference Period Ended September 30, 1998
Conversions - Heating Only

Line No.	Month	Lagged Normal DDays	X Coefficient	Product	Constant	Normalized Usage per Customer	No. of Customers In Sample	Normalized Volumes	Actual Volumes	Weather Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Residential - Class 1 Rate 1									
1	Oct-97	29.0	0.0144	0.4172	0.0129	0.4301	31	13.33	20.4	(7.07)
2	Nov-97	239.0	0.0144	3.4385	0.0129	3.4514	31	106.99	216.7	(109.71)
3	Dec-97	520.0	0.0144	7.4813	0.0129	7.4942	31	232.32	320.3	(87.98)
4	Jan-98	859.0	0.0144	12.3586	0.0129	12.3715	31	383.52	372.7	10.82
5	Feb-98	1,007.0	0.0144	14.4879	0.0129	14.5008	31	449.52	365.1	84.42
6	Mar-98	793.0	0.0144	11.4090	0.0129	11.4219	31	354.08	298.8	55.28
7	Apr-98	553.0	0.0144	7.9561	0.0129	7.9690	31	247.04	141.7	105.34
8	May-98	246.0	0.0144	3.5392	0.0129	3.5521	31	110.12	58.6	51.52
9	Jun-98	93.0	0.0144	1.3380	0.0129	1.3509	31	41.88	5.0	36.88
10	Jul-98	1.0	0.0144	0.0144	0.0129	0.0273	31	0.85	0.7	0.15
11	Aug-98	0.0	0.0144	0.0000	0.0129	0.0129	31	0.40	0.1	0.30
12	Sep-98	0.0	0.0144	0.0000	0.0129	0.0129	31	0.40	1.2	(0.80)
13										
14	Total	4,340			0.0129		31	1,940.45	1,801.30	139.15
15	Average Usage / Customer							62.60	58.11	

Western Kentucky Gas Company
Normalization Of Volumes For Weather
Reference Period Ended September 30, 1998
Appliance Percentages

Line No.	Category/Appliances	FY 1995	FY 1997	Total	Appliance Percentage	% of New Market
	(a)	(b)	(c)	(d)	(e)	(f)
1	Residential New Construction:					
2	Heating & Water Heating	1,908	1,382	3,290	82.7%	
3	Heating Only	318	362	680	17.1%	
4	Water Heating Only	10	-	10	0.3%	
5	Total			3,980		66.9%
6						
7	Residential Conversions:					
8	Heating & Water Heating	174	138	312	15.9%	
9	Heating Only	814	710	1,524	77.6%	
10	Water Heating Only	107	22	129	6.6%	
11	Total			1,965		33.1%
12						
13						
14						

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 138
Witness: Doggette

Data Request:

List all the different pressures utilized by Western in the operation of its system, and explain the operation of Western's system with respect to change in gas pressures and the reason for the changes in gas pressures.

Response:

Western's primary gas supplies are delivered from an interstate pipeline system, normally at pressures between 400 and 700 psig, and received at our Town Border stations. The Town Border station performs two primary functions:

1. It reduces the interstate pipeline pressure to Western's desired operating pressure
2. It odorizes the natural gas as required by 807 KAR 5:022 Gas Safety and Service, Section 13 - Operations, Subsection (17) Odorization

The pipe that receives the gas at the Town Border station and transports it to Western's distribution system is called a transmission line (TP) or high pressure (HP) distribution line, ranging in pressure from 70 to 960 psig. Typical operating pressures of HP lines are from 175 psig to 400 psig. Typical transmission lines operate from over 400 to 960 psig. The differentiation between high pressure and transmission is based on the design factor of the facility. The transmission lines and high pressure distribution lines operate at pressures designed to meet the requirements of 807 KAR 5:022 Gas Safety and Service for design, construction, testing, operation and maintenance while providing capacity to deliver gas at sufficient pressure to supply the downstream distribution system. The operating pressure is determined by the location of the gas source, peak load delivery requirements and or delivery pressure requirements by industrial customers.

The distribution system receives the gas from the transmission line at a city gate regulator station. The regulator station reduces the pressure to 60 psig or less. Western's distribution system is normally qualified to operate at 60 psig or less, called Intermediate Pressure (IP). Typical IP pressures range from 45 to 60 psig in the larger towns and 20 to 50 psig in the smaller towns. Western also utilizes low pressure (LP) systems in certain areas. The low pressure system receives gas from the distribution system at or below 3 psig and delivers it to the customer at utilization pressure of 0.25 psig per 807 KAR 5:022 Gas Safety and Service, Section 13 - Operations, Subsection (13) Maximum and Minimum Operating Pressure.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 139-a,b,c,d,e
Witness: Hack

Data Request:

For 1996, 1997 and 1998, please provide the following information regarding Western's distribution (gas delivery) system:

a. The highest peak day and each classes' contribution to that peak day:;

b. The non-coincident peak (NCP) by the class and time of occurrence;

c. The highest three-day peak and each classes' contribution to that three-day peak;

d. Western's design peak day;

e. The amount of firm and interruptible load by rate class in the CP and NCP data; and

Response:

a. See Response to AG DR Item 122

b. Not available

c. See Attachment AG DR Item 139 (c) (d)

d. See Attachment AG DR Item 139 (c) (d)

e. Not available

139(c)

WESTERN KENTUCKY THREE DAY PEAK PERIODS (INCLUDING THIRD PARTY TRANSPORTS)

	1/11/97	1/12/97	1/13/97
Mean Temp	6 Deg. F	11 Deg. F	9 Deg. F
Total Throughput	321,641	311,785	349,834
	3/10/98	**3/11/98**	**3/12/98**
Mean Temp	25 Deg. F	20 Deg. F	26 Deg. F
Total Throughput	273,471	305,234	260,303
	1/3/99	**1/4/99**	**1/5/99**
Mean Temp	23 Deg. F	14 Deg. F	24 Deg. F
Total Throughput	310,249	344,234	302,278

• Daily Requirements by customer class are not available.

139(d)

Winter 96 - 97

	Design Peak Day 96/97
Mean Temp	
Total Throughput	432,100

Winter 97 - 98

	Design Peak Day 97/98
Mean Temp	
Total Throughput	436,940

Winter 98 - 99

	Design Peak Day 98/99
Mean Temp	
Total Throughput	404,150

Note: All volumes stated in MCF.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 139-f
Witness: Petersen

Data Request:

For 1996, 1997 and 1998, please provide the following information regarding Western's distribution (gas delivery) system:

f. A reconciliation of these factors with the demand allocators utilized in Western's gas cost of service study.

Response:

f. The demand allocators in Western's class cost of service study are Design-A, Design-B, A&P and A&P/Gas from page 16 of the study and Rb-Dem from page 17 of the study. The Design-A allocator is based on total demands used in the development of the design day for the test year with no reduction for the amounts that would be curtailed on the design day. The Design-B allocator is based on total firm service demands in the design day study for the test year, excluding curtailment priorities 5 through 7. The A&P and A&P/Gas allocators are based on the Design-B allocator. The Rb-Dem allocator is derived from the application of the other allocators to rate base.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 140
Witness: Smith

Data Request:

Explain why the GRI R&D Unit charge is not applicable to T-3 and T-4 carriage service, as proposed.

Response:

Please see Western's response to KPSC's First Data Request - Item 52c.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 141
Witness: Smith

Data Request:

Will application of the Waiver Provision discretion included in the GRI tariff cause the unit charge to increase for other customers subject to the charge? Explain.

Response:

No. It is Western's philosophy that the implementation or any change in the GRI R&D unit charge should not increase the GRI unit cost applicable to any rate or customer class in relation to December 31, 1998 GRI funding levels. To shift costs from one rate or class to another would require Commission approval.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 142
Witness: Smith

Data Request:

142. Why is the DSM surcharge proposed to be applicable only to residential customers?

Response:

KRS 278.285 requires the assignment of the cost of DSM programs only to the class or classes of customers which benefit from the programs. The customers that benefit from the program are a segment of the residential customer class, therefore, the charge is proposed to be applied to the residential customer class.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 143
Witness: Smith

Data Request:

143. If a cost basis is claimed for the application of the DSM surcharge only to the residential rate class, please explain how a residential customer who does not participate in the DSM program is anymore responsible for the incurrence of the DSM costs than a customer in any other class.

Response:

A cost basis is not claimed. KRS 278.285 requires the assignment of the cost of DSM programs only to the class or classes of customers which benefit from the programs. The customers that benefit from the program are a segment of the residential customer class, therefore, the charge is proposed to be applied to the residential customer class.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 144
Witness: Marks

Data Request:

144. As detailed as possible, describe costs that are incurred by or on behalf of the collaborative process. (Marks' testimony, page 20, lines 5-6.)

Response:

The costs that are incurred by or on behalf of the collaborative process include consultant fees for program design, pre-implementation benefit/cost screening results report and a process and impact evaluation report. The collaborative meeting costs and program management costs have been paid by Western, and not applied to the collaborative process costs.

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 145
Witness: Smith and Marks

Data Request:

145. Please provide workpapers detailing the actual and estimated expenses shown on Exhibit MM-2.

Response:

The attachment shows the workpapers for the actual expenses as shown on Exhibit MM-2. Estimated expenses were obtained by reviewing the actual expenses for the program through 10/31/98. There are no workpapers for the estimated expenses.

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WKG CARES MONTHLY REPORT (interim) - DECEMBER 1996

AGENCY		FUNDS				HOMES	
	Begin Bal	December	FY 1997		Begin Bal	December	FY 1997
Audubon	$0.00	$2,139.49	$2,139.49		0	2	2
Blue Grass	$0.00	$0.00	$0.00		0	0	0
Pennyrile	$0.00	$5,574.46	$5,574.46		0	4	4
Southern KY	$0.00	$2,673.66	$2,673.66		0	2	2
West KY	$0.00	$0.00	$0.00		0	0	0
sub total	$0.00	$10,387.61	$10,387.61		0	8	8
Collaborative	$19,455.43	$300.30	$19,755.73				
TOTALS	$19,455.43	$10,687.91	$30,143.34		0	8	8

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WKG CARES MONTHLY REPORT (interim) - JANUARY 1997

AGENCY		FUNDS				HOMES	
	Begin Bal	January	FY 1997		Begin Bal	January	FY 1997
Audubon	$2,139.49	$5,931.89	$8,071.38		2	5	7
Blue Grass	$0.00	$0.00	$0.00		0	0	0
Pennyrile	$5,574.46	$9,755.36	$15,329.82		4	7	11
Southern KY	$2,673.66	$3,857.56	$6,531.22		2	4	6
West KY	$0.00	$1,500.00	$1,500.00		0	1	1
sub total	$10,387.61	$21,044.81	$31,432.42		8	17	25
Collaborative	$19,755.73	$2,430.00	$22,185.73				
TOTALS	$30,143.34	$23,474.81	$53,618.15		8	17	25

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WKG CARES MONTHLY REPORT (interim) - February 1997

AGENCY		FUNDS				HOMES	
	Begin Bal	February	FY 1997		Begin Bal	February	FY 1997
Audubon	$8,071.38	$2,981.20	$11,052.58		7	2	9
Blue Grass	$0.00	$2,203.68	$2,203.68		0	2	2
Pennyrile	$15,329.82	$5,540.69	$20,870.51		11	4	15
Southern KY	$6,531.22	$3,745.42	$10,276.64		6	4	10
West KY	$1,500.00	$7,500.00	$9,000.00		1	5	6
sub total	$31,432.42	$21,970.99	$53,403.41		25	17	42
Collaborative	$22,185.73	$2,558.98	$24,744.71				
TOTALS	$53,618.15	$24,529.97	$78,148.12		25	17	42

DR 145

WKG CARES MONTHLY REPORT (interim) - March 1997

AGENCY		FUNDS				HOMES	
	Begin Bal	March	FY 1997		Begin Bal	March	FY 1997
Audubon	$11,052.58	$0.00	$11,052.58		9		9
Blue Grass	$2,203.68	$0.00	$2,203.68		2		2
Pennyrile	$20,870.51	$10,258.44	$31,128.95		15	7	22
Southern KY	$10,276.64	$1,512.00	$11,788.64		10	1	11
West KY	$9,000.00	$4,498.00	$13,498.00		6	3	9
sub total	$53,403.41	$16,268.44	$69,671.85		42	11	53
Collaborative	$24,744.71	$5,393.11	$30,137.82				
TOTALS	$78,148.12	$21,661.55	$99,809.67		42	11	53

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A[illegible]DR 145

WKG CARES MONTHLY REPORT (interim) - April 1997

AGENCY		FUNDS				HOMES	
	Begin Bal	April	FY 1997		Begin Bal	April	FY 1997
Audubon	$11,052.58	$563.14	$11,615.72		9	1	10
Blue Grass	$2,203.68	$0.00	$2,203.68		2	0	2
Pennyrile	$31,128.95	$22,871.93	$54,000.88		22	11	33
Southern KY	$11,788.64	$3,095.12	$14,883.76		11	3	14
West KY	$13,498.00	$13,500.00	$26,998.00		9	9	18
sub total	$69,671.85	$40,030.19	$109,702.04		53	24	77
Collaborative	$30,137.82	$2,364.00	$32,501.82				
GRAND TOTAL	$99,809.67	$42,394.19	$142,203.86		53	24	77

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WKG CARES MONTHLY REPORT (interim) - May 1997

AGENCY		FUNDS				HOMES	
	Begin Bal	May	FY 1997		Begin Bal	May	FY 1997
Audubon	$11,615.72	$4,470.07	$16,085.79		10	4	14
Blue Grass	$2,203.68	$1,440.00	$3,643.68		2	1	3
Pennyrile	$54,000.88	$8,368.63	$62,369.51		33	6	39
Southern KY	$14,883.76	$5,358.04	$20,241.80		14	6	20
West KY	$26,998.00	$4,223.00	$31,221.00		18	3	21
sub total	$109,702.04	$23,859.74	$133,561.78		77	20	97
Collaborative	$32,501.82		$32,501.82				
GRAND TOTAL	$142,203.86	$23,859.74	$166,063.60		77	20	97

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WKG CARES MONTHLY REPORT (interim) - June 1997

AGENCY		FUNDS		Avg/Home		HOMES	
	Begin Balance	June	Program Year 1997	Prog Year 1997	Begin Balance	June	Prog Year 1997
Audubon	$16,085.79	$2,412.94	$18,498.73	$1,088.16	14	3	17
Blue Grass	$3,643.68	$0.00	$3,643.68	$1,214.56	3	0	3
Pennyrile	$62,369.51	$3,191.70	$65,561.21	$1,394.92	39	8	47
Southern KY	$20,241.80	$3,121.01	$23,362.81	$973.45	20	4	24
West KY	$31,221.00	$0.00	$31,221.00	$1,486.71	21	0	21
sub total	$133,561.78	$8,725.65	$142,287.43	$1,270.42	97	15	112
Collaborative	$32,501.82	$288.00	$32,789.82				
GRAND TOTAL	$166,063.60	$9,013.65	$175,077.25				

copies: J. Carnahan, G. Smith, G, Milligan, L. Moore, B. Boyd
H. Jones, B. Vincent, S. White, M. McGill, S. West
A. Chevront, S. Crocker, K. Bowmar, M. Marks

08/30/1999

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WKG CARES MONTHLY REPORT (interim) - July 1997

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	July	Program Year 1997	Program Year 1997	Begin Balance	July	Prog Year 1997
Audubon	$18,498.73	$3,142.89	$21,641.62	$1,139.03	17	2	19
Blue Grass	$3,643.68	$1,631.46	$5,275.14	$1,318.79	3	1	4
Pennyrile	$65,561.21	$5,598.41	$71,159.62	$1,395.29	47	4	51
Southern KY	$23,362.81	$13,370.39	$36,733.20	$1,080.39	24	10	34
West KY	$31,221.00	$1,466.25	$32,687.25	$1,485.78	21	1	22
sub total	$142,287.43	$25,209.40	$167,496.83	$1,288.44	112	18	130
Collaborative	$32,789.82	$600.00	$33,389.82				
GRAND TOTAL	$175,077.25	$25,809.40	$200,886.65				

copies: J. Carnahan, G. Smith, G, Milligan, L. Moore, B. Boyd
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08/30/1999

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WKG CARES MONTHLY REPORT (interim) - August 1997

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	August	Program Year 1997	Program Year 1997	Begin Balance	August	Prog Year 1997
Audubon	$21,641.62	$5,207.32	$26,848.94	$1,220.41	19	3	22
Blue Grass	$5,275.14	$1,345.49	$6,620.63	$1,324.13	4	1	5
Pennyrile	$71,159.62	$1,512.25	$72,671.87	$1,397.54	51	1	52
Southern KY	$36,733.20	$6,742.02	$43,475.22	$1,144.08	34	4	38
West KY	$32,687.25	$1,500.00	$34,187.25	$1,486.40	22	1	23
sub total	$167,496.83	$16,307.08	$183,803.91	$1,312.89	130	10	140
Collaborative	$33,389.82		$33,389.82				
GRAND TOTAL	$200,886.65	$16,307.08	$217,193.73				

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A. Chevront, S. Crocker, K. Bowmar, M. Marks
H. Jones, B. Vincent, S. White, M. McGill, S. West

AG-DR 145

WKG CARES MONTHLY REPORT (interim) - September 1997

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	September	Program Year 1997	Program Year 1997	Begin Balance	Sept	Prog Year 1997
Audubon	$26,848.94	$10,903.97	$37,752.91	$1,348.32	22	6	28
Blue Grass	$6,620.63	$1,648.16	$8,268.79	$1,378.13	5	1	6
Pennyrile	$72,671.87	$4,284.65	$76,956.52	$1,399.21	52	3	55
Southern KY	$43,475.22	$8,597.23	$52,072.45	$1,183.46	38	6	44
West KY	$34,187.25	$7,279.50	$41,466.75	$1,480.96	23	5	28
sub total	$183,803.91	$32,713.51	$216,517.42	$1,344.83	140	21	161
Collaborative	$33,389.82		$33,389.82				
GRAND TOTAL	$217,193.73	$32,713.51	$249,907.24				

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AG-AR 145

WKG CARES MONTHLY REPORT (interim) - October 1997

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	October	Program Year 1997	Program Year 1997	Begin Balance	Oct	Prog Year 1997
Audubon	$37,752.91	$1,510.56	$39,263.47	$1,308.78	28	2	30
Blue Grass	$8,268.79	$0.00	$8,268.79	$1,378.13	6	0	6
Pennyrile	$76,956.52	$10,807.13	$87,763.65	$1,438.75	55	6	61
Southern KY	$52,072.45	$10,684.65	$62,757.10	$1,255.14	44	6	50
West KY	$41,466.75	$7,500.00	$48,966.75	$1,483.84	28	5	33
sub total	$216,517.42	$30,502.34	$247,019.76	$1,372.33	161	19	180
Collaborative	$33,389.82	$0.00	$33,389.82	$185.50			
GRAND TOTAL	$249,907.24	$30,502.34	$280,409.58	$1,557.83			

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WKG CARES MONTHLY REPORT (interim) - November 1997

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	November	Program Year 1998	Program Year 1998	Begin Balance	Nov	Prog Year 1998
Audubon	$0.00	$8,496.16	$8,496.16	$1,699.23	0	5	5
Blue Grass	$0.00	$2,869.65	$2,869.65	$1,434.83	0	2	2
Pennyrile	$0.00	$10,794.86	$10,794.86	$1,199.43	0	9	9
Southern KY	$0.00	$2,445.12	$2,445.12	$1,222.56	0	2	2
West KY	$0.00	$6,000.00	$6,000.00	$1,500.00	0	4	4
sub total	$0.00	$30,605.79	$30,605.79	$1,391.17	0	22	22
Collaborative	$0.00	$0.00	$0.00	$0.00			
GRAND TOTAL	$0.00	$30,605.79	$30,605.79	$1,391.17			

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WKG CARES MONTHLY REPORT (interim) - December 1997

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	December	Program Year 1998	Program Year 1998	Begin Balance	Dec	Prog Year 1998
Audubon	$8,496.16	$9,342.06	$17,838.22	$1,621.66	5	6	11
Blue Grass	$2,869.65	$1,205.51	$4,075.16	$1,358.39	2	1	3
Pennyrile	$10,794.86	$1,443.37	$12,238.23	$1,112.57	9	2	11
Southern KY	$2,445.12		$2,445.12	$1,222.56	2		2
West KY	$6,000.00	$4,271.00	$10,271.00	$1,467.29	4	3	7
sub total	$30,605.79	$16,261.94	$46,867.73	$1,378.46	22	12	34
Collaborative	$0.00	$0.00	$0.00	$0.00			
GRAND TOTAL	$30,605.79	$16,261.94	$46,867.73	$1,378.46			

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WKG CARES MONTHLY REPORT (interim) - January 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	January	Program Year 1998	Program Year 1998	Begin Balance	Jan	Prog Year 1998
Audubon	$17,838.22	$7,644.31	$25,482.53	$1,698.84	11	4	15
Blue Grass	$4,075.16	$0.00	$4,075.16	$1,358.39	3	0	3
Pennyrile	$12,238.23	$3,252.84	$15,491.07	$1,191.62	11	2	13
Southern KY	$2,445.12	$8,488.67	$10,933.79	$1,561.97	2	5	7
West KY	$10,271.00	$7,500.00	$17,771.00	$1,480.92	7	5	12
sub total	$46,867.73	$26,885.82	$73,753.55	$1,475.07	34	16	50
Collaborative	$0.00	$4,128.00	$4,128.00	$82.56			
GRAND TOTAL	$46,867.73	$31,013.82	$77,881.55	$1,557.63			

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WKG CARES MONTHLY REPORT (interim) - February 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	February	Program Year 1998	Program Year 1998	Begin Balance	Feb	Prog Year 1998
Audubon	$25,482.53	$4,581.62	$30,064.15	$1,582.32	15	4	19
Blue Grass	$4,075.16	$835.04	$4,910.20	$1,227.55	3	1	4
Pennyrile	$15,491.07	$8,610.96	$24,102.03	$1,268.53	13	6	19
Southern KY	$10,933.79	$1,794.80	$12,728.59	$1,414.29	7	2	9
West KY	$17,771.00	$3,000.00	$20,771.00	$1,483.64	12	2	14
sub total	$73,753.55	$18,822.42	$92,575.97	$1,424.25	50	15	65
Collaborative	$4,128.00	$3,528.00	$7,656.00	$117.78			
GRAND TOTAL	$77,881.55	$22,350.42	$100,231.97	$1,542.03			

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WKG CARES MONTHLY REPORT - March 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	March	Program Year 1998	Program Year 1998	Begin Balance	Mar	Prog Year 1998
Audubon	$30,064.15	$9,129.09	$39,193.24	$1,633.05	19	5	24
Blue Grass	$4,910.20	$0.00	$4,910.20	$1,227.55	4	0	4
Pennyrile	$24,102.03	$13,116.05	$37,218.08	$1,329.22	19	9	28
Southern KY	$12,728.59	$6,835.83	$19,564.42	$1,504.96	9	4	13
West KY	$20,771.00	$4,087.00	$24,858.00	$1,462.24	14	3	17
sub total	**$92,575.97**	**$33,167.97**	**$125,743.94**	**$1,462.14**	**65**	**21**	**86**
Collaborative	$7,656.00	$14,910.00	$22,566.00	$262.40			
GRAND TOTAL	**$100,231.97**	**$48,077.97**	**$148,309.94**	**$1,724.53**			

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WKG CARES MONTHLY REPORT - April 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	April	Program Year 1998	Program Year 1998	Begin Balance	Apr	Prog Year 1998
Audubon	$39,193.24	$4,930.10	$44,123.34	$1,634.20	24	3	27
Blue Grass	$4,910.20	$3,080.91	$7,991.11	$1,331.85	4	2	6
Pennyrile	$37,218.08	$7,730.03	$44,948.11	$1,123.70	28	12	40
Southern KY	$19,564.42	$8,255.24	$27,819.66	$1,264.53	13	9	22
West KY	$24,858.00	$0.00	$24,858.00	$1,462.24	17	0	17
sub total	$125,743.94	$23,996.28	$149,740.22	$1,336.97	86	26	112
Collaborative	$22,566.00	$15,475.00	$38,041.00	$339.65			
GRAND TOTAL	$148,309.94	$39,471.28	$187,781.22	$1,676.62			

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WKG CARES MONTHLY REPORT - May 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	May	Program Year 1998	Program Year 1998	Begin Balance	May	Prog Year 1998
Audubon	$44,123.34	$5,807.72	$49,931.06	$1,610.68	27	4	31
Blue Grass	$7,991.11	$1,565.87	$9,556.98	$1,365.28	6	1	7
Pennyrile	$44,948.11	$7,019.34	$51,967.45	$1,105.69	40	7	47
Southern KY	$27,819.66		$27,819.66	$1,264.53	22		22
West KY	$24,858.00		$24,858.00	$1,462.24	17		17
sub total	$149,740.22	$14,392.93	$164,133.15	$1,323.65	112	12	124
Collaborative	$38,041.00	$18,486.50	$56,527.50	$455.87			
GRAND TOTAL	$187,781.22	$32,879.43	$220,660.65	$1,779.52			

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WKG CARES MONTHLY REPORT - June 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	June	Program Year 1998	Program Year 1998	Begin Balance	June	Prog Year 1998
Audubon	$49,931.06	$4,712.93	$54,643.99	$1,821.47	27	3	30
Blue Grass	$9,556.98		$9,556.98	$1,592.83	6		6
Pennyrile	$51,967.45		$51,967.45	$1,299.19	40		40
Southern KY	$27,819.66	$4,456.70	$32,276.36	$1,291.05	22	3	25
West KY	$24,858.00		$24,858.00	$1,462.24	17		17
sub total	$164,133.15	$9,169.63	$173,302.78	$1,468.67	112	6	118
Collaborative	$56,527.50	$13,723.55	$70,251.05	$595.35			
GRAND TOTAL	$220,660.65	$22,893.18	$243,553.83	$2,064.02			

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WKG CARES MONTHLY REPORT - July 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	July	Program Year 1998	Program Year 1998	Begin Balance	July	Prog Year 1998
Audubon	$54,643.99	$227.86	$54,871.85	$1,770.06	30	1	31
Blue Grass	$9,556.98	$1,702.16	$11,259.14	$1,608.45	6	1	7
Pennyrile	$51,967.45		$51,967.45	$1,299.19	40		40
Southern KY	$32,276.36	$3,456.45	$35,732.81	$1,323.44	25	2	27
West KY	$24,858.00	$6,000.00	$30,858.00	$1,469.43	17	4	21
sub total	$173,302.78	$11,386.47	$184,689.25	$1,465.79	118	8	126
Collaborative	$70,251.05	$3,016.00	$73,267.05	$581.48			
GRAND TOTAL	$243,553.83	$14,402.47	$257,956.30	$2,047.27			

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WKG CARES MONTHLY REPORT - August 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	August	Program Year 1998	Program Year 1998	Begin Balance	August	Prog Year 1998
Audubon	$54,871.85	$4,856.81	$59,728.66	$1,706.53	31	4	35
Blue Grass	$11,259.14	$1,753.04	$13,012.18	$1,626.52	7	1	8
Pennyrile	$51,967.45	$3,226.89	$55,194.34	$1,283.59	40	3	43
Southern KY	$35,732.81	$9,397.26	$45,130.07	$1,367.58	27	6	33
West KY	$30,858.00	$4,500.00	$35,358.00	$1,473.25	21	3	24
sub total	$184,689.25	$23,734.00	$208,423.25	$1,457.51	126	17	143
Collaborative	$73,267.05	$0.00	$73,267.05	$512.36			
GRAND TOTAL	$257,956.30	$23,734.00	$281,690.30	$1,969.86			

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WKG CARES MONTHLY REPORT - September 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	September	Program Year 1998	Program Year 1998	Begin Balance	Sept	Prog Year 1998
Audubon	$59,728.66	$2,160.22	$61,888.88	$1,672.67	35	2	37
Blue Grass	$13,012.18	$0.00	$13,012.18	$1,626.52	8	0	8
Pennyrile	$55,194.34	$3,818.20	$59,012.54	$1,282.88	43	3	46
Southern KY	$45,130.07	$4,158.48	$49,288.55	$1,369.13	33	3	36
West KY	$35,358.00	$1,500.00	$36,858.00	$1,474.32	24	1	25
sub total	$208,423.25	$11,636.90	$220,060.15	$1,447.76	143	9	152
Collaborative	$73,267.05	$11,002.75	$84,269.80	$554.41			
GRAND TOTAL	$281,690.30	$22,639.65	$304,329.95	$2,002.17			

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WKG CARES MONTHLY REPORT - October 1998

AGENCY	FUNDS			Avg/Home	HOMES		
	Begin Balance	October	Program Year 1998	Program Year 1998	Begin Balance	Oct	Prog Year 1998
Audubon	$61,888.88	$0.00	$61,888.88	$1,672.67	37	0	37
Blue Grass	$13,012.18	$3,874.69	$16,886.87	$1,535.17	8	3	11
Pennyrile	$59,012.54	$2,275.18	$61,287.72	$1,276.83	46	2	48
Southern KY	$49,288.55	$5,936.61	$55,225.16	$1,380.63	36	4	40
West KY	$36,858.00	$1,500.00	$38,358.00	$1,475.31	25	1	26
sub total	$220,060.15	$13,586.48	$233,646.63	$1,442.26	152	10	162
Collaborative	$84,269.80	$0.00	$84,269.80	$520.18			
GRAND TOTAL	$304,329.95	$13,586.48	$317,916.43	$1,962.45			

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08/30/1999

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 146
Witness: Smith

Data Request:

With regard to Mr. Smith's testimony on pages 10-11, please provide all workpapers and supporting documentation showing:

a. The development of the weighting percentages assigned to the five NOAA First Order Weather Stations.

b. The derivation of the composite normal of 4340 HDDs.

Response:

a. See response to AG DR 97.

b. See source documents, NOAA report on "Climatography in the United States No. 84" provided in response to AG DR 98. This report was used to determine 30 year annual normal by NOAA weather station.

See attached schedule deriving composite normal of 4340 HDDs.

WESTERN KENTUCKY GAS COMPANY
Composite Normal Heating Degree Days

Months	Louisville NOAA Station	Nashville NOAA Station	Lexington NOAA Station	Evansville NOAA Station	Paducah NOAA Station	Composite Normal
Jan	1032	893	1060	1082	1004	1007
Feb	820	689	854	857	787	793
Mar	580	469	611	595	550	553
Apr	273	193	312	273	231	246
May	105	59	135	114	83	93
Jun	6	0	5	0	0	1
Jul	0	0	0	0	0	0
Aug	0	0	0	0	0	0
Sep	36	21	47	33	24	29
Oct	254	195	287	266	228	239
Nov	537	450	570	564	513	520
Dec	871	760	902	924	859	859
Total HDDs	4514	3729	4783	4708	4279	**4340**
Weighting Factor	0.028	0.215	0.156	0.222	0.379	1.00000

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 147
Witness: Smith

Data Request:

Please provide a copy of any memoranda, studies, or other written documents which discuss the selection of the appropriate NOAA Stations for purposes of calculating HDDs, the time period to be utilized in defining normal HDDs, and other considerations researched and assessed by Western in consideration of proposing a WNA.

Response:

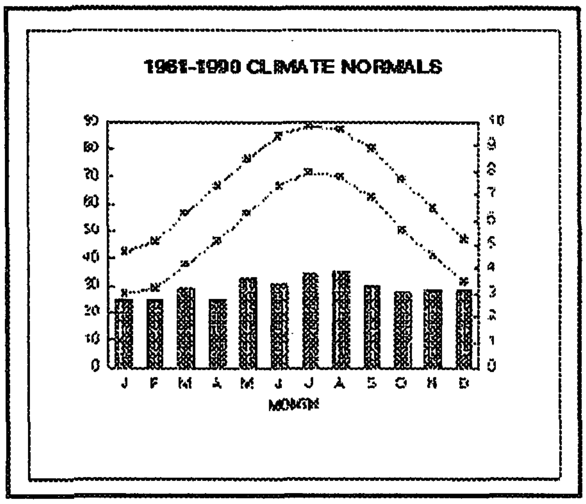
Atmos' experience at United Cities Gas has led Western to understand the importance of using the most reliable and accessible daily weather data derived from first order NOAA weather stations in the existing WNA programs.

The attached document, "U.S. National 1961-1990 Climate Normals", is published by the National Climatic Data Center (NOAA), and provides an explanation of the rationale for use of the 30 year normal data utilized in this case.

Also attached is NOAA document TD-9641, "1961-90 Daily Station Normals of Temperature, Precipitation, Degree Days" which further discusses the recommended use of stylized data by NOAA.

Also, see the attached response to KPSC DR #1 – Item 59(b) for the actual analysis conducted by Western supporting the selection of weather stations in determining degree days.

Lastly, the attached graph plots the comparison of Western's former versus proposed degree day basis to Western's historical usage (Mcf) per customer per year. The graph clearly demonstrates the improved predictability and curve fit of Western's proposed degree day basis.



U.S. National 1961-1990 Climate Normals

May 14, 1997

***"Climate Normal"** - Definition: The arithmetic average of a meteorological element over 30 years.*

- Introduction
- Interpretation of "Climatic Normals"
- Overview of the 1961-90 United States Climate Normals Products
- Normals from Earlier Periods
- On What Output Media Are the Normals Available?
- **Who Do I Email to find out What Normals Are Available and How To Order Them?**

Introduction

Climate is an important factor in agriculture, commerce, industry, and transportation. It is a natural resource that affects many human activities such as farming, fuel consumption, structural design, building site location, trade, analysis of market fluctuations, and the utilization of other natural resources. The influence of climate on our lives is endless. The National Oceanic and Atmospheric Administration's (NOAA's) National Climatic Data Center (NCDC) inherited the U.S. Weather Bureau's responsibility to fulfill the mandate of Congress "... to establish and record the climatic conditions of the United States," an important provision of the Organic Act of October 1, 1890, which established the Weather Bureau as a civilian agency (15 U.S.C. 311).

The mandate to describe the climate was combined with guidelines established through international agreement. The end of a decade has been set by the World Meteorological Organization (WMO) as the desirable term for a 30-year period from which to calculate climatic conditions. The average value of a meteorological element over the 30 years is defined as a climatological normal. The normal climate helps in describing the climate and is used as a base to which current conditions can be compared.

Every ten years, NCDC computes new thirty-year climate normals for selected temperature and precipitation elements for a large number of U.S. climate and weather stations. These normals are summarized in several products which will be discussed later in this home page. Every thirty years, climatological standard normals are computed as part of an international effort led by the WMO. The period 1961-90 corresponds to the latest WMO standard normals period.

Interpretation of "Climatic Normals"

The term climatic "normal" has faced a dilemma since it's introduction a century and a half ago. As noted by Guttman (1989, p. 602), "Climatologists generally understand that a normal is simply an average of a climatic element over thirty years.... a normal value is usually not the most frequent value nor the value above which half the cases fall."

The general public, however, tends to (erroneously) perceive the normal as what they should expect. Dr. Helmut E. Landsberg, who became Director of Climatology of the U.S. Weather Bureau in 1954 and, later, Director of the Environmental Data Service, summarized the dilemma quite well four decades ago (Landsberg, 1955): "The layman is often misled by the word. In his every-day language the word normal means something ordinary or frequent. ...When (the meteorologist) talks about 'normal', it has nothing to do with a common event..... For the meteorologist the 'normal' is simply a point of departure or index which is convenient for keeping track of weather statistics..... We never expect to experience 'normal' weather."

It might be "normal" for the weather to swing radically between extremes from day to day and year to year, but the *"climatic normal"* is simply an arithmetic average of what has happened at such a "swinging" place. This is why it's important to use a measure of the *variability* of climate (such as the standard deviation and extremes) in conjunction with the climatic normal when studying the climate of a location (Guttman, 1989).

Overview of the 1961-90 United States Climate Normals Products

The 1961-90 U.S. climate normals are summarized and published in four primary products, designated CLIM81, CLIM84, CLIM85, and CLIM20. The normals also appear in several other products. Each product contains the normals appropriate for the application and users the product was designed for (Element Table).

The normals that are most commonly computed are 30-year averages for precipitation and maximum, minimum, and mean temperature for each of the 12 months, plus an annual value. Monthly and annual average heating and cooling degree days are also important. The CLIM81 ***(Climatography of the United States No. 81)*** publication contains these monthly normals, plus monthly median precipitation and median mean temperature, for several thousand locations across the country (4775 temperature stations and 6662 precipitation stations).

Daily normals are computed for 422 National Weather Service offices and principal climatological stations for the following six elements: precipitation, heating and cooling degree days, and maximum, minimum, and mean temperature. The daily station normals are summarized in the CLIM84 ***(Climatography of the United States No. 84)*** publication.

The contiguous United States, Alaska, Puerto Rico, and the U.S. Virgin Islands are divided into 360 geographical units called climate divisions. Monthly and annual divisional normals for mean temperature, precipitation, and heating and cooling degree days, as well as the corresponding standard deviation for these four elements, are published in the CLIM85 ***(Climatography of the United States No. 85)*** publication. Monthly and annual normals for the corresponding States and Territories, nine Census Regions, and national values for the contiguous United States, are derived from the divisional data and published in the ***Historical Climatology Series 4-1, 4-2, 5-1, and 5-2*** publications.

Normals statistics that have useful agricultural applications are published in the CLIM20 *(Climatography of the United States No. 20)* publication. These statistics include freeze date probabilities; normal growing degree days; monthly number of days with temperature, precipitation, and snowfall beyond various thresholds; monthly precipitation probabilities; temperature and precipitation "runs" statistics (consecutive number of days beyond various thresholds); and temperature, precipitation, and snowfall extremes, as well as the CLIM81 monthly normals. CLIM20 summaries are being prepared for approximately 2900 locations in the United States.

The 1961-90 normals appear in several other NCDC publications, including the ***Local Climatological Data, Annual Summary*** ; ***Comparative Climatic Data*** ; ***Climatic Averages and Extremes for U.S. Cities*** ; and three supplements to the CLIM81 publication (***Monthly Precipitation Probabilities*** , ***Annual Degree Days to Selected Bases*** , and ***Maps of Annual 1961-90 Normal Temperature, Precipitation, and Degree Days***).

NCDC computed 1961-90 normals for several additional elements for several hundred U.S. stations as the U.S. submission to the WMO global standard normals project. These elements include monthly mean wind speed and wind direction frequencies, atmospheric pressure (mean sea level), relative humidity, sunshine duration, cloud cover, wet bulb/dew point temperatures, and number of days meeting specified criteria, including: thunderstorms, rain/drizzle, freezing rain/drizzle, snow/hail, fog/mist, smoke/haze, blowing snow, and dust storm/sandstorm.

Normals from Earlier Periods

In the United States, normals have been computed for 1961-90, 1951-80, 1941-70, 1931-60, and 1921-50. The normals from 1931-60 to present are in NCDC's archives. The 1921-50 normals, which were the first normals set prepared according to WMO standards, were published in 1956 as ***Weather Bureau Technical Paper No. 31 (Monthly Normal Temperatures, Precipitation, and Degree Days)*** . This technical paper is available from NCDC only on microfiche.

These earlier normals have been summarized in previous editions of the CLIM81, CLIM84, CLIM85, and CLIM20 publications (Station Table). In addition, a comprehensive *Climatic Atlas of the United States* presents the 1931-60 normals in large map format; the 1951-80 freeze/frost probabilities have been summarized in a separate volume; and selected normals summaries have been collated into individual state volumes.

Statistical summaries which further describe the climate of the United States have been published as CLIM82 and CLIM90. These summaries are based primarily on hourly data and present tables of means and frequency of occurrence of selected climatic elements.

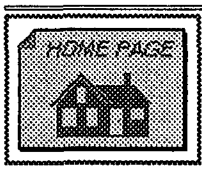
Normals are best used as a base against which climate during the following decade can be measured. Comparison of normals from one 30-year period to normals from another 30-year period may lead to erroneous conclusions about climatic change. This is due to changes over the decades in station location, in the instrumentation used, in how weather observations were made, and in how the various normals were computed. The differences between normals due to these ***non-climatic*** changes may be larger than the differences due to a true change in climate.

On What Output Media Are the Normals Available?

The 1931-60 through 1961-90 climate normals discussed on this home page are available as printed publications, on microfiche, and/or digitally on magnetic tape. Please contact the NCDC Climate Services Division to determine the availability of any particular product, or if you have any questions. The Climate Services Division can be reached by telephone (828-271-4800), fax (828-271-4876), or via the internet:

orders@ncdc.noaa.gov

All of the normals files in NCDC's digital archive (through the end of 1996) have been loaded onto one CD-ROM. This ***USDS - Vol. 1.0*** CD-ROM contains only the documentation files and ASCII text data in the NCDC archive tape format; the data are **not** importable into a spreadsheet and the CD-ROM contains **no** software or extraction routines that allow users to import the data directly into spreadsheets or other applications.



Back to the National Climatic Data Center Home Page

Richard Heim, Normals Program Manager .....

For questions, contact: orders@ncdc.noaa.gov

1961-90 DAILY STATION NORMALS OF TEMPERATURE, PRECIPITATION, DEGREE DAYS.

TD-9641

National Climatic Data Center
Federal Building
Asheville, North Carolina

JANUARY 1993

This document was prepared by the U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Enviromental Satellite Data and Information Service, National Climatic Data Center, Asheville, North Carolina.

This document is designed to provide general information on the current, origin, format, integrity and the availability of this data file.

Errors found in this document should be brought to the attention of the Data Base Administrator, NCDC. See topics 58 for a summary of this data set.

Table of Contents

1. Data Set ID

TD9641.

2. Data Set Name

1961-90 DAILY STATION NORMALS OF TEMPERATURE, PRECIPITATION, AND DEGREE DAYS.

3. Data Set Aliases

Not applicable.

4. Access Method and Sort for Archived Data

The data in this data set are archived on one labeled cartridge tape in two fixed length files. The first file contains the daily normals data values for National Weather Service Offices and Principal Climatological Stations identified by their COOP station number. The second file is a cross reference table identifying the stations by name.

Daily Normals Data File

The daily normals data are archived in a fixed length (record size = 1102, block size = 1102) ASCII format. Each record has the following format:

```
 Columns     Description and Codes
---------    ---------------------
   1-   6    COOP Station Number
   7-   7    Element Code.  Values are:
                1 = Maximum Temperature
                2 = Minimum Temperature
                3 = Mean Temperature
                4 = Heating Degree Days
                5 = Cooling Degree Days
                6 = Precipitation
The remainder of the record consists of 365 Data Values, one
for each day of the year, each three numeric characters
long.  A value of -99 represents a value greater than 0 but
less than 1.  The temperature and degree day values are in
whole units (Fahrenheit), while the precipitation values are
in hundredths of an inch.
   8-  10    Daily Normal for January 1
  11-  13    Daily Normal for January 2
  14-  16    Daily Normal for January 3
   etc.         etc.
1100-1102    Daily Normal for December 31
```

Station Name List File

The station name list file is a cross reference table that identifies each station by name and number. The station's latitude, longitude, and elevation (in feet above mean sea level) are also identified. Each fixed length ASCII record (record size = 60, block size = 3000) describes one station and has the following format:

Columns	Description and Codes
1- 6	COOP Station Number Columns 1-2 are the state identifier:

01 Alabama	19 Massachusetts	37 Rhode Island
02 Arizona	20 Michigan	38 South Carolina
03 Arkansas	21 Minnesota	39 South Dakota
04 California	22 Mississippi	40 Tennessee
05 Colorado	23 Missouri	41 Texas
06 Connecticut	24 Montana	42 Utah
07 Delaware	25 Nebraska	43 Vermont
08 Florida	26 Nevada	44 Virginia
09 Georgia	27 New Hampshire	45 Washington
10 Idaho	28 New Jersey	46 West Virginia
11 Illinois	29 New Mexico	47 Wisconsin
12 Indiana	30 New York	48 Wyoming
13 Iowa	31 North Carolina	49 not used
14 Kansas	32 North Dakota	50 Alaska
15 Kentucky	33 Ohio	51 Hawaii
16 Louisiana	34 Oklahoma	66 Puerto Rico
17 Maine	35 Oregon	67 Virgin Islands
18 Maryland	36 Pennsylvania	91 Pacific Islands

Columns	Description and Codes
7- 9	not used
10-38	Station Name
39-40	Latitude (degrees)
41-42	Latitude (minutes)
43-43	Latitude (hemisphere: N=North, S=South)
44-46	not used
47-49	Longitude (degrees)
50-51	Longitude (minutes)
52-52	Longitude (hemisphere: W=West, E=East)
53-55	not used
56-60	Elevation (feet)

5. Access Method and Sort for Supplied Data

Same as Topic 4 (Access Method and Sort for Archived Data).

6. Element Names and Definition

The elements consist of the following: station cooperative I.D. number, climatic element (maximum, minimum, and mean temperatures, heating and cooling degree days, and precipitation), nd 365 daily normal data values.

7. Start Date

The normals period covered by this data set is 1961-1990. The Start Date is therefore 1961.

8. Stop Date

The normals period covered in this data set is 1961-1990. The Stop Date is therefore 1990.

9. Parameter

The daily normal values were not computed by averaging 30 years of daily observations. The daily normal values were interpolated from the much less variable monthly normal values by use of the natural spline function as described by Greville (1967). The procedure involved constructing a cumulative series of monthly sums from the monthly normals. The cumulative series was for a 24-month period (July, ... December, January, ... December, January, ... June) so the interpolating function could adequately fit the end points of the annual series. This process was applied independently to all six elements. No normal values for February 29 are included here; in common practice the normal values for the 28th are used for the 29th in each leap year. Thus, for leap years, the February monthly total degree day values are calculated by adding the daily value for the 28th to the printed monthly total. The February temperature and precipitation monthly values are not adjusted for leap years.

Environmental Information Summary C-28 has a more detailed discussion of the daily normals procedure.

Computation of Degree Days

The daily heating and cooling degree day normals were interpolated from the monthly heating and cooling degree day normals using the natural spline function, as noted above. The MONTHLY heating and cooling degree day normals are themselves derived quantities. The monthly degree day normals were derived from the sequential monthly temperature data using the technique developed by Thom (1954a, 1954b, 1966). This procedure is discussed in greater detail in the publication, CLIMATOGRAPHY OF THE UNITED STATES NO. 81: MONTHLY STATION NORMALS OF TEMPERATURE, PRECIPITATION, AND HEATING AND COOLING DEGREE DAYS, 1961-1990.

10. Discipline

Earth Science>Atmosphere>Meteorology
Earth Science>Atmosphere>Climatology
Earth Science>Atmosphere>Hydrology
Earth Science>Land>Agriculture

11. Coverage

latitude range: 14d20m S to 71d18m N
longitude range: 134d29m E to 67d47m W

12. Location

In situ station data across the USA, including the 50 States and Possessions (Puerto Rico, Virgin Islands, and Pacific Islands).

13. Keyword

Meteorology
Climatology
Hydrology
Agriculture
Building and Construction
Construction
Maximum Temperature
Minimum Temperature
Mean Temperature
Heating Degree Days
Cooling Degree Days
Normals
Spline Algorithm
TD9641
9641

14. Storage Medium

The digital data are archived on a fixed length ASCII format in two files on one labeled cartridge tape.

15. File Mode

ASCII

16. How to Acquire the Data

Ask NCDC's Customer Service Group about costs and how to order the data. Call 704-259-0682 or write to: Customer Service Group, National Climatic Data Center, Federal Building, 37 Battery Park Avenue, Asheville, NC 28801-2733.

17. Historical and Current Data Sources

TD-9641 (1961-90 Monthly Station Normals) all Elements.

18. Data Derivation, Algorithms

The daily normal values were not computed by averaging 30 years of daily observations. The daily normal values were interpolated from the much less variable monthly normal values by use of the natural spline function as described by Greville (1967).

Computation of Degree Days

The daily heating and cooling degree day normals were interpolated from the monthly heating and cooling degree day normals using the natural spline function, as noted above. The MONTHLY heating and cooling degree day normals are themselves derived quantities. The monthly degree day normals were derived from the sequential monthly temperature data using the technique developed by Thom (1954a, 1954b, 1966).

19. Data Derivation Algorithms, Responsibility for

NCDC

20. Project

Decadal U.S. Climate Census

21. Data Center, Archiving

National Climatic Data Center
NOAA/NESDIS/NCDC
Federal Building
37 Battery Park Avenue
Asheville, NC 28801-2733

22. Data Center, Originating

National Climatic Data Center
Federal Building
37 Battery Park Avenue
Asheville, NC 28801-2733

23. Archiver

Chief, Data Base Management Branch
NOAA/NCDC
Federal Building
37 Battery Park Avenue
Asheville, NC 28801-2733

24. Technical Contact

Climate Services Division
NOAA/NCDC
Federal Building
37 Battery Park Avenue
Asheville, NC 28801-2733
phone: 704-259-0682

25. Investigator

Data Base Management Branch
NOAA/NCDC
37 Battery Park Avenue
Asheville, NC 28801-2733

26. Sensor Name and Operating Principles

No information available at this time.

27. Sensor Sitting

No information available at this time.

28. Sensor Accuracy and Calibration

No information available at this time.

29. Sensor Sampling Characteristics

No information available at this time.

30. Data Capture Method at/near Sensor

No information available at this time.

31. Station Location Accuracy

No information available at this time.

32. Station Observation Schedule

No information available at this time.

33. Station Data Time Averaging

No information available at this time.

34. Station Grouping, Using Spatial Sampling

No information available at this time.

35. Network Participation

The stations in this data set are National Weather Service Offices and Principal Climatological Stations.

36. Geographical Criteria for Selecting Stations

No information available at this time.

37. Geographical Distribution

There are 486 stations in this data set, most of which are located in or near major metropolitan areas.

38. Elevation Distribution

Most of the stations had elevations below 1000 meters above sea level. The minimum elevation is -34 meters (-112 feet) and the maximum is 2297 meters (7536 feet).

39. Instrument Problems

No information available at this time.

40. Missing Data Periods

Not applicable.

41. Sampling Biases

No information available at this time.

42. Error Detectiion and Correction

No information available at this time.

43. Missing Value Estimates

Not applicable.

44. Quality Control Responsibility

No information available at this time.

45. Known uncorrected Problems

No information available at this time.

46. Confidence Factors

No information available at this time.

47. History of Data Usage

No information available at this time.

48. Quality Statement

No information available at this time.

49. Revision Date

January 1, 1993.

50. Science Review Datre

January 1, 1993.

51. Future Review Date

Not applicable.

52. Input Sources to this Data Set

This data set used monthly normal data from the TD-9641: 1961-90 MONTHLY STATION NORMALS ALL ELEMENTS data set as input.

53. Essential Companion Data Sets

Not applicable.

54. Derived from this Data Set

Not applicable.

55. Larger Collections

Not applicable.

56. Similar Data Sets

Daily Normals are available for earlier 30-year Normals Periods.

57. Reference

The following references describe computational procedures, computational algorithms, and input data sets relevant to this data set:

Greville, T.N.E., 1967: "Spline functions, interpolation, and numerical quadrature," MATHEMATICAL METHODS OF DIGITAL COMPUTERS, Volume 2 (edited by A. Ralston and H.S. Wilf). John Wiley and Sons, Inc., New York.

Thom, H.C.S., 1954a: "The rational relationship between heating degree days and temperature." MONTHLY WEATHER REVIEW, vol. 82, pp. 1-6.

Thom, H.C.S., 1954b: "Normal degree days below any base." MONTHLY WEATHER REVIEW, vol. 82, pp. 111-115.

Thom, H.C.S., 1966: "Normal degree days above any base by the universal truncation coefficient." MONTHLY WEATHER REVIEW, vol. 94, pp. 461-465.

CLIMATOGRAPHY OF THE UNITED STATES NO. 81: MONTHLY STATION NORMALS OF TEMPERATURE, PRECIPITATION, AND HEATING AND COOLING DEGREE DAYS, 1961-1990. National Climatic Data Center, Asheville, NC.

CLIMATOGRAPHY OF THE UNITED STATES NO. 84: DAILY NORMALS OF TEMPERATURE, PRECIPITATION AND HEATING AND COOLING DEGREE DAYS, 1961-1990. National Climatic Data Center, Asheville, NC.

ENVIRONMENTAL INFORMATION SUMMARY C-23: "1961-90 Climatic Normals". National Climatic Data Center, Asheville, NC.

ENVIRONMENTAL INFORMATION SUMMARY C-28: "Climatography of the United States No. 84: Daily Normals and Precipitation Probabilities". National Climatic Data Center, Asheville, NC.

58. Summary

This tape consists of 2 files containing station identification information and daily normals values for the 1961-90 period for 486 U.S. stations. The climatic elements include maximum, minimum, and mean temperature, heating and cooling degree days, and precipitation. The daily normals were computed from the monthly normals using a natural spline interpolation algorithm.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 59 (b)
Witness: Smith

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Degree Day Basis: Former WKG Method															
2																
3			RESIDENTIAL VOLUMES							COMMERCIAL & PUBLIC AUTHORITY VOLUMES						
4		% Normal	Actual	Total Act	Annual	Normal	Normal	Meters	Normal	Actual	Total Act	Annual	Normal	Normal	Meters	Normal
5		DD	BL/mo	Volume	Heating Load	Heating Load	Total	in Svc	per Cust	BL/mo	Volume	Heating Load	Heating Load	Total	in Svc	per Cust
6																
7	FY 90	90.3%	256,004	12,594,525	9,522,477	10,544,568	13,616,616	133,588	101.93	189,347	6,401,691	4,129,527	4,572,768	6,844,932	16,012	427.49
8	FY 91	81.3%	257,793	11,786,006	8,692,490	10,697,120	13,790,636	135,612	101.69	198,297	5,944,397	3,564,839	4,386,949	6,766,507	16,158	418.77
9	FY 92	88.2%	259,035	12,415,482	9,307,068	10,554,181	13,662,595	140,975	96.92	171,364	6,109,353	4,052,991	4,596,077	6,652,439	16,938	392.75
10	FY 93	95.5%	269,910	13,288,027	10,049,107	10,527,752	13,766,672	143,120	96.19	204,054	6,906,207	4,457,565	4,669,881	7,118,523	17,549	405.64
11	FY 94	100.2%	252,128	13,861,028	10,835,498	10,813,038	13,838,568	145,689	94.99	185,005	7,447,460	5,227,406	5,216,571	7,436,625	18,148	409.78
12	FY 95	87.5%	247,727	11,987,742	9,015,024	10,301,186	13,273,904	149,014	89.08	229,197	6,735,841	3,985,477	4,554,080	7,304,444	18,495	394.94
13	FY 96	106.4%	248,341	14,718,174	11,738,085	11,032,781	14,012,870	151,378	92.57	225,049	8,036,092	5,335,504	5,014,911	7,715,499	18,885	408.55
14	FY 97	96.4%	248,955	13,337,468	10,350,008	10,733,984	13,721,444	153,720	89.26	220,901	7,508,906	4,858,094	5,038,325	7,689,137	19,248	399.48
15	FY 98	87.0%	251,963	12,561,176	9,537,626	10,959,038	13,982,588	155,846	89.72	213,619	7,066,080	4,502,652	5,173,692	7,737,120	19,620	394.35
16																
17	Degree Day Basis: Proposed WKG Method															
18																
19			RESIDENTIAL VOLUMES							COMMERCIAL & PUBLIC AUTHORITY VOLUMES						
20		% Normal	Actual	Total Act	Annual	Normal	Normal	Meters	Normal	Actual	Total Act	Annual	Normal	Normal	Meters	Normal
21		DD	BL/mo	Volume	Heating Load	Heating Load	Total	in Svc	per Cust	BL/mo	Volume	Heating Load	Heating Load	Total	in Svc	per Cust
22																
23	FY 90	92.5%	256,004	12,594,525	9,522,477	10,290,725	13,362,773	133,588	100.03	189,347	6,401,691	4,129,527	4,462,686	6,734,850	16,012	420.61
24	FY 91	85.0%	257,793	11,786,006	8,692,490	10,223,687	13,317,203	135,612	98.20	198,297	5,944,397	3,564,839	4,192,792	6,572,350	16,158	406.76
25	FY 92	89.1%	259,035	12,415,482	9,307,068	10,442,781	13,551,195	140,975	96.12	171,364	6,109,353	4,052,991	4,547,565	6,603,927	16,938	389.89
26	FY 93	96.3%	269,910	13,288,027	10,049,107	10,438,756	13,677,676	143,120	95.57	204,054	6,906,207	4,457,565	4,630,405	7,079,047	17,549	403.39
27	FY 94	101.3%	252,128	13,861,028	10,835,498	10,695,033	13,720,563	145,689	94.18	185,005	7,447,460	5,227,406	5,159,641	7,379,695	18,148	406.64
28	FY 95	84.4%	247,727	11,987,742	9,015,024	10,675,363	13,648,081	149,014	91.59	229,197	6,735,841	3,985,477	4,719,501	7,469,865	18,495	403.89
29	FY 96	109.4%	248,341	14,718,174	11,738,085	10,729,421	13,709,510	151,378	90.56	225,049	8,036,092	5,335,504	4,877,019	7,577,607	18,885	401.25
30	FY 97	99.4%	248,955	13,337,468	10,350,008	10,409,973	13,397,433	153,720	87.15	220,901	7,508,906	4,858,094	4,886,241	7,537,053	19,248	391.58
31	FY 98	92.5%	251,963	12,561,176	9,537,626	10,314,801	13,338,351	155,846	85.59	213,619	7,066,080	4,502,652	4,869,551	7,432,979	19,620	378.85
32																
33																
34	BL/month is based on actual metered volumes for months of July and August preceeding the stated Fiscal Year winter period.															

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 59 (b)
Witness: Smith

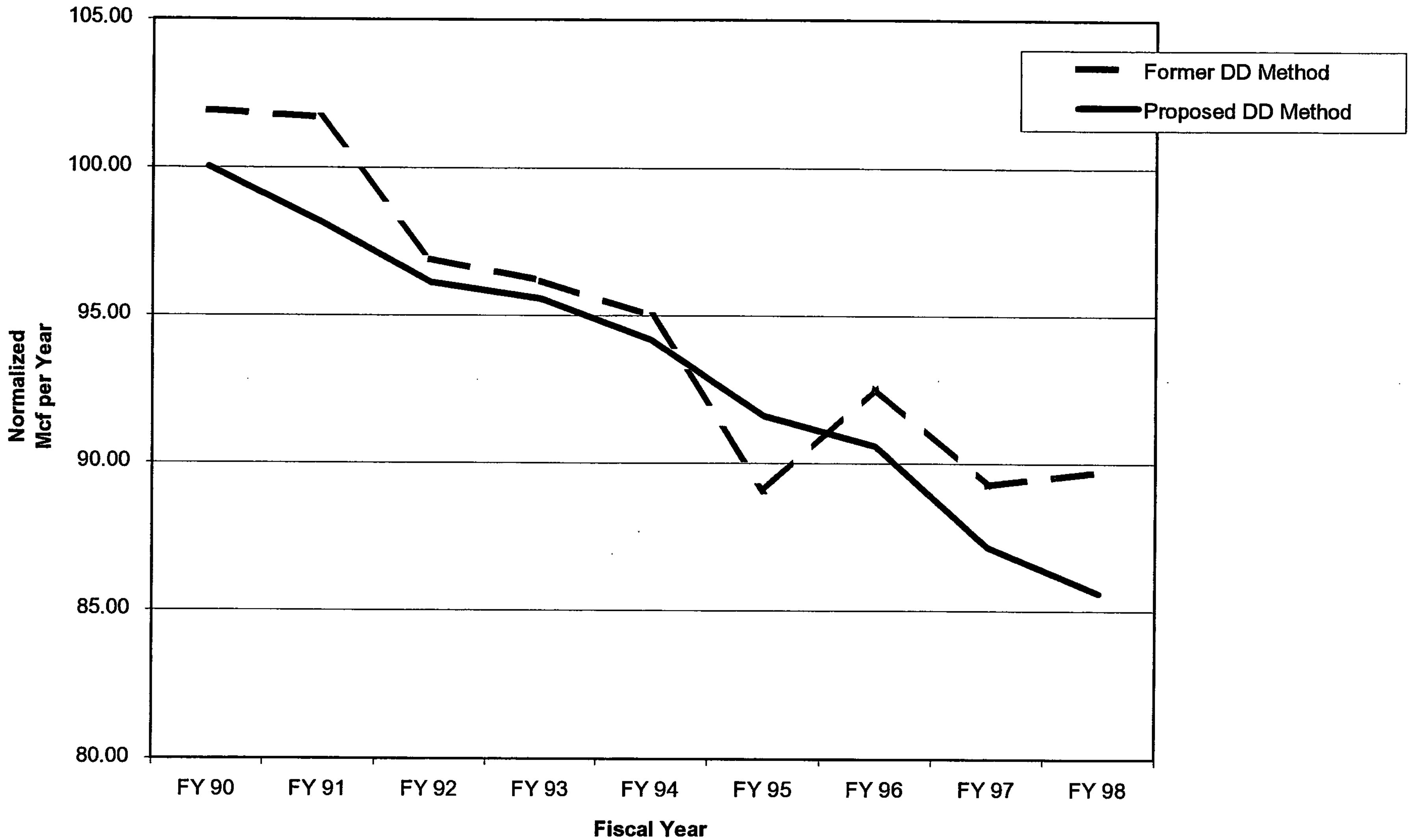
Line No.	(a)	(b) Lexington	(c) Louisville	(d) Paducah	(e) Evansville	(f) Nashville	(g) Proposed	(h) Former
	% Allocation	15.61%	2.80%	37.92%	22.22%	21.44%		
1	**Oct**	287	254	228	266	195	239	239
2	**Nov**	570	537	513	564	450	520	515
3	**Dec**	902	871	859	924	760	859	859
4	**Jan**	1060	1032	1004	1082	893	1,007	1,006
5	**Feb**	854	820	787	857	689	793	793
6	**Mar**	611	580	550	595	469	553	556
7	**Apr**	312	273	231	273	193	246	242
8	**May**	135	105	83	114	59	93	92
9	**Jun**	5	6	0	0	0	1	2
10	**Jul**	0	0	0	0	0	-	-
11	**Aug**	0	0	0	0	0	-	-
12	**Sep**	47	36	24	33	21	29	29
13								
14	**Normal**	4783	4514	4279	4708	3729	4,340	4,333

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 59 (b)
Witness: Smith

Line No.	(a)	(b) Lexington	(c) Louisville	(d) Paducah	(e) Evansville	(f) Nashville	(g) Proposed	(h) Former
1	Oct-89	267	230	193	225	158	205	
2	Nov-89	592	539	488	577	408	508	
3	Dec-89	1297	1222	1165	1297	1095	1,202	
4	Jan-90	720	672	651	707	590	662	
5	Feb-90	608	574	534	603	422	538	
6	Mar-90	505	445	438	487	373	446	
7	Apr-90	378	320	313	358	245	319	
8	May-90	128	82	89	97	65	92	
9	Jun-90	17	13	10	15	1	10	
10	Jul-90	0	0	0	2	0	-	
11	Aug-90	3	0	1	1	0	1	
12	Sep-90	57	34	28	35	21	33	
13								
14	FY 1990	4572	4131	3910	4404	3378	4,016	3,913
15	% Norm						92.5%	90.3%
16								
17	Oct-90	288	229	273	291	195	261	
18	Nov-90	453	387	352	432	323	380	
19	Dec-90	757	745	771	828	654	756	
20	Jan-91	955	949	949	1037	791	936	
21	Feb-91	719	677	642	702	586	656	
22	Mar-91	544	482	429	528	402	465	
23	Apr-91	215	167	119	191	80	143	
24	May-91	34	27	18	42	9	24	
25	Jun-91	0	0	0	0	0	-	
26	Jul-91	0	0	0	0	0	-	
27	Aug-91	0	0	0	0	0	-	
28	Sep-91	77	52	72	88	42	69	
29								
30	FY 1991	4042	3715	3625	4139	3082	3,690	3,521
31	% Norm						85.0%	81.3%
32								
33	Oct-91	230	168	190	227	166	199	
34	Nov-91	642	590	585	647	535	597	
35	Dec-91	765	725	709	791	628	719	
36	Jan-92	915	855	827	913	768	848	
37	Feb-92	682	610	556	673	544	601	
38	Mar-92	600	523	470	549	456	506	
39	Apr-92	293	244	228	259	217	243	
40	May-92	159	124	86	118	85	105	
41	Jun-92	17	8	5	10	2	7	
42	Jul-92	0	0	0	0	0	-	
43	Aug-92	5	0	0	0	0	1	
44	Sep-92	64	40	39	46	26	42	
45								
46	FY 1992	4372	3887	3695	4233	3427	3,868	3,821
47	% Norm						89.1%	88.2%

AG DR No. 1
Item 147

Normalized Residential Usage Calculations
(Comparing Former and Proposed Degree Day Bases)



Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 148
Witness: Gary Smith

Data Request:

148. Please explain in detail how the Company proposes to calculate base load (BL) and the heat sensitive factor (HSF) for purposes of its WNA.

Response:

Please refer to the response to KPSC Data Request No. 1, dated July 16, 1999, Item 49(b). Also refer to responses to this Initial Attorney General Data Request, DR Items 151 and 152 pertaining to requested calculations of the BL and HSF for the winter season of 1998-99.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 149
Witness: Gary Smith

Data Request:

149. Please state whether the Company is proposing to determine normal degree days (NDDs) for WNA purposes in the same manner as discussed on pages 10-11 of Mr. Smith's testimony. If not, please explain in detail how Western intends to calculate NDDs for WNA purposes.

Response:

Yes. The referenced testimony, specifically on page 10, lines 29-30 through page 11, lines 1-2, details the source for our computation of NDDs. Information relating to the determination of NDDs can also be found in this Initial AG Data Request, Items 97 and 98.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated August 19, 1999
DR Item 150
Witness: Gary Smith

Data Request:

150. Please identify each rate schedule and billing classification for which Western is proposing to develop a separate Weather Normalization Adjustment Factor (WNA factor).

Response:

As stated in pre-filed testimony, Volume 2 of 10 of the Application, Tab 11, at Page 37, Lines 17-21, and as indicated in the proposed tariff, P.S.C. No. 20, First Revised Sheet No. 26, the proposed WNA rider would apply to residential, commercial and public authority classes under G-1 Sales Service. Thus, three WNA factors for each billing cycle will be developed.