COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

RATE ADJUSTMENT OF WESTERN KENTUCKY GAS COMPANY ON NOTICE	))	CASE NO. 9556

O R D E R

On May 9, 1986, Western Kentucky Gas Company ("Western") filed its notice with the Commission seeking authority to increase its rates for service rendered to its customers by $3.6 million or 2.4 percent over normalized test period revenues, as determined herein, to become effective June 1, 1986. Western stated that the additional revenue was necessary to pay increased debt, salary, insurance and conservation program costs. In this Order, the Commission has granted additional operating revenues of $1,761,410 or 1.2 percent over normalized test year revenues.

In order to determine the reasonableness of the request for additional revenues the Commission suspended the proposed rate increase until November 1, 1986. Western was directed to give notice to its customers of the proposed rates and the scheduled hearing pursuant to 807 KAR 5:025. A motion to intervene in this proceeding was filed by the Consumer Protection Division in the Office of the Attorney General ("AG"). This motion was granted and no other parties formally intervened.

A public hearing was held in the Commission's offices in Frankfort, Kentucky on September 9, 1986, with the parties of record represented. Briefs were filed by October 6, 1986, and responses to all data requests have been submitted.

COMMENTARY

Western is a division of Texas American Energy Corporation ("TAE") and provides natural gas service to approximately 132,500 customers in western and central Kentucky. Western's primary pipeline suppliers are Texas Gas Transmission Corporation and Tennessee Gas Pipeline Company.

TEST PERIOD

Western proposed and the Commission has accepted the 12-month period ending February 28, 1986, as the test period for determining the reasonableness of the proposed rates. In utilizing the historical test period the Commission has given full consideration to appropriate known and measurable changes.

VALUATION

Western presented the net original cost rate base and capital structure as valuation methods in this case. The Commission has considered these and other elements of value in determining the reasonableness of the proposed rates.

Net Original Cost

Western proposed a test-year-end jurisdictional rate base of $68,004,139. The Commission is of the opinion that the proposed rate base is proper and acceptable for rate-making purposes with the exception that an adjustment has been made to reflect the accepted pro forma adjustments to operation and maintenance expenses in the calculation of the allowance for working capital.

The effect of this adjustment is to reduce the proposed rate base by $51,622.

Therefore, the net original cost rate base devoted to utility jurisdictional service is determined by the Commission to be as follows:

Utility Plant in Service	$ 99,766,724
Construction Work in Progress	1,107,379
Gas Stored Underground - Non-Current	1,775,865
Total Utility Plant	$102,649,968
ADD:	
Materials and Supplies	$ 1,200,486
Gas Stored Underground - Current	12,927,205
Prepaid Gas Purchases-Average	2,842,936
Prepayments	508,293
Working Capital	2,217,331
Subtotal	$ 19,696,251
DEDUCT:	
Accumulated Depreciation	$ 44,872,036
Customer Advances for Construction	2,014,790
Deferred Income Taxes	7,359,143
Unamortized Investment Tax Credit	147,733
Subtotal	$ 54,393,702
NET ORIGINAL COST RATE BASE	$ 67,952,517

Capitalization

Western proposed a jurisdictional capital structure of $60,413,095 which consisted of $30,230,839 (50.04 percent) of common equity, $22,630,218 (37.46 percent) of long-term debt, $5,696,490 (9.43 percent) of short-term debt, and $1,855,548 (3.07 percent) of customer deposits. The foregoing amounts include the allocation of Job Development Investment Tax Credits ("JDIC") to each component based upon its ratio to total capitalization excluding JDIC as proposed by Western.

The Commission has disallowed the inclusion of customer deposits in capital structure in accordance with past practice and because the Commission does not consider customer deposits to be a component of permanent capitalization and has based the short-term debt component upon the actual test-year-end balance rather than a 13-month average as proposed by Western.

The Commission therefore finds Western's test-year-end capital structure to be as follows:

	Amount	Percent
Equity Capital	$30,315,934	53.46
Long-Term Debt	22,693,951	40.02
Short-Term Debt	3,702,228	6.52
TOTAL	$56,712,113	100.00

REVENUES AND EXPENSES

Western had net operating income of $5,427,477 during the test period. In order to reflect more current and anticipated operating conditions, Western proposed several adjustments to its test period revenues and expenses which resulted in an adjusted net operating income of $5,381,206.[1] The Commission is of the opinion that the proposed adjustments are generally proper and acceptable for rate-making purposes with the following exceptions:

---

1 Application, Exhibit 5, page 1.

Normalized Revenues

The Commission accepts as reasonable the majority of Western's adjustments to normalized revenue. The weather normalization adjustment is consistent with methodology used by Western and approved by the Commission in the past. The roll-in of transportation sales into actual gas sales is a logical treatment of gross margin transportation sales. The loss of industrial sales volumes in the test year is clearly known and measurable and of a magnitude never experienced by Western in the past. The full adjustment proposed by Western for loss of industrial sales is justified by the record and is accordingly approved in this rate case. It must be understood, however, that this adjustment is to be made on a one-time basis; there has been no evidence presented that a continuous, steady and predictable decline in industrial sales is to be the rule and not the exception for Western in the future.

Western priced sales volumes using a pro forma gas cost adjustment ("GCA") factor that was to adjust sales levels so that gas cost recoveries and gas costs incurred through Case No. 8839-Z would match on a dollar-for-dollar basis. This methodology is based on a GCA mechanism proposed by Western in this case. The Commission, therefore, has adjusted normalized test-year sales revenue to reflect the current rates actually in effect as of April 1, 1986, as approved by the Commission in its Order in Case No. 8839-Z.

Based upon the above, the Commission has determined total normalized revenues to be $149,810,182; this is a combination of normalized sales revenues of $149,527,859 and other revenues of $282,323 that remained unadjusted in the test year.

Institutional Advertising

Western proposed an adjustment to reduce operating expenses by $40,994 to reflect the elimination of institutional advertising as required by 807 KAR 5:016, Section 4; the charges eliminated represented the balance of Account No. 320.1--General Advertising Expenses.

In order to evaluate the adjustment proposed by Western, the Commission requested detailed information including copies of advertisements as well as the text of all advertising campaigns charged to Account No. 909--Informational and Instructional Advertising Expenses.[2] A review of the information provided by Western reflected that the purpose of these advertisements was to promote the use of natural gas and natural gas appliances in favor of electricity and electric appliances. Western stated in its brief that the representative advertisements provided are clearly allowable expenses in accordance with the advertising regulation.[3]

Section 4 of 807 KAR 5:016 specifically states that advertising for the purpose of encouraging any person to select or use the service or additional service of an energy utility, or the selection or installation of any appliance or equipment designed to use such utility's service is deemed to be promotional advertising and

---

2 Additional information provided by witness as requested at hearing.

3 Western's Brief, page 8.

not includible in the utility's cost of service for rate-making purposes.

The context of the newspaper, radio and television advertisements provided by Western have the clear message of encouraging the use of gas service and the selection or installation of appliances and equipment designed to use gas. The burden of proof that advertising should be included in the cost of service rests with Western in this instance. The Commission is of the opinion that Western has not provided persuasive evidence that these advertisements are not promotional. Therefore, the Commission has eliminated from operating expenses all of the advertisement charges to Account No. 909 through these media. This results in a further reduction to operating expenses of $105,096.[4]

The Commission has reconsidered its past practice of not including for rate-making purposes advertising costs associated with Western's "Helping Hands Program." This program is for the purpose of raising funds to help those unable to pay their heating bills during the winter. The Commission believes this to be a commendable program and in the best interests of the public and ratepayers, and will therefore allow for rate-making purposes advertising costs associated with its promotion. Such charges during the test year were $18,677. The Commission has therefore reclassified this amount from a non-operating to an operating expense. Western should continue to provide the Commission with

---

4 Response to the Commission's First Information Request, Item No. 25a.

representative advertisements promoting the "Helping Hands Program" so that the Commission may continue to monitor their text.

The aforementioned adjustments related to advertising costs result in a net reduction in operating expenses of $127,413.

Wages and Salaries

Western initially proposed an adjustment to increase wages and salaries expense by $531,755. This amount was reduced in an amended adjustment by $27,510, based upon the finalization of a wage contract effective June 1, 1986.[5] The normalization of wage and salary increases occurring during the test year reflected approximately a 4.9 percent annual increase in labor costs, while the post test period increases averaged approximately 4.5 percent. No intervenor objected to the adjustments proposed by Western and the Commission is of the opinion that, in this instance, the inclusion of such costs is reasonable and appropriate for rate-making purposes.

The Commission has noted and appreciated that many utilities have recently renegotiated to lower wage contracts, as did Western in one instance. The Commission notes, however, that the level of increases granted during the past several years by Western was excessive relative to the inflation rates as measured by the Consumer Price Index. The 1984 increase of 8.67 percent compares with a 1984 inflation rate of 4 percent; the 1985 increase of 5 percent compares with a 1985 inflation rate of 3.8 percent; and

---

5 Response to the Commission's Third Information Request, Item No. 1.

the 4.5 percent 1986 increase effective June 1, 1986, compares with a 1.7 percent inflation rate for the preceding 12 months. The Commission encourages Western to keep abreast of wage adjustments and renegotiate wage contracts if necessary to assure that wages and salaries are maintained at reasonable levels.

Interest Synchronization

As proposed by Western, the Commission has imputed interest expense on the portion of JDIC assigned to the debt components of the capital structure to compute the interest expense in determining the federal income tax expense allowed in the cost of service.

The Commission has calculated an interest adjustment of $93,400 based upon the allowed debt components and their respective cost rates.[6] This results in an increase to income taxes of $46,621.[7]

6

		Interest Expense
Long-Term Debt	$22,693,951	
Cost of Long-Term Debt	11.44%	$2,596,188
Short-Term Debt	3,702,228	
Cost of Short-Term Debt	8.50%	314,689
Adjusted Interest Expense		$2,910,877
Test Year Interest Expense		3,004,277
INTEREST ADJUSTMENT		$ 93,400

7

Interest Adjustment	$93,400
Tax Rate	.49915
	$46,621

Texas American Oil Audit Expense

During the test year, Western reported $39,400 as its allocated portion of an expense incurred for an audit of a TAE subsidiary, Texas American Oil ("TAO"). In response to cross-examination at the hearing, Western stated that it was responsible for a portion of this expense because it was related to corporate level operations in Midland, Texas, and that it was normal and recurring. Western did not, however, know how this amount was calculated, and expressed that it did not believe a portion of Western's audit was allocated to TAO.[8]

The Commission does not find this to be a persuasive justification for incurring a portion of the cost of the audit of another corporation. Moreover, the Commission notes that about $33,500 is allocated to Western from TAE for tax and audit expenses as a portion of the corporate allocation expense discussed elsewhere in this Order.

Western has failed to demonstrate the benefits to its ratepayers associated with this expense. The Commission has therefore reduced operating expenses by $39,400 to exclude this expense from the cost of service.

Corporate Allocation

Western proposed an adjustment to increase operating expenses by $108,000 to reflect an increase in the allocation of corporate expenses from its parent, TAE. The proposed increase is based

[8] Transcript of Evidence ("T.E."), September 9, 1986, page 42.

upon a total projected annual allocation by TAE of $738,300 of which Western's share is $456,000; the test year allocation was $348,000. Western states that these costs are for its proportionate share of administrative and general costs which the company would incur directly if it were not a division of its parent.[9] Specifically, these costs represent such expenses as tax and auditing fees, reporting fees, stock transfer and AMEX fees, shareholder reporting, director fees, etc.

The Commission does not disagree with the validity of the allocation of such parent-company expenses to its subsidiary and divisional operations. The Commission is, however, charged with the responsibility of investigating and determining the reasonableness of the amounts allocated to entities under its jurisdiction. It was within this vein that the Commission investigated this issue.

Western has provided its calculation showing the expenses and amounts which result in the $456,000 total. The amounts represent approximately 63 percent of the total costs allocated by TAE; 63 percent represents the ratio of Western's assets to the assets of all TAE divisions and subsidiaries.

The Commission has attempted to determine through its requests for information and cross-examination of witnesses the basis for allocating corporate expenses according to the ratio of net assets and the source of the amounts being allocated.

---

9 Greable Testimony, page 11.

Western, it appears, has little involvement in the decisions regarding the corporate allocation.[10] The management of TAE established the procedure of allocating corporate costs based upon net assets, but the specific reasons for this are unknown to Western.[11] Moreover, the allocation amount is provided by TAE to Western without supporting detail. Western, it appears, must accept and pay the corporate allocation as directed by its parent.

The Commission is of the opinion that Western has not met its burden of proof in justifying the proposed adjustment. Moreover, the Commission notes that the corporate allocation expense has increased considerably since the time of Western's last rate proceeding. As of the date of the Final Order in Case No. 8839 (December 1, 1983), the monthly corporate allocation fee was $23,657, whereas the current fee is $38,000.[12] This represents an increase of over 60 percent in only 3 years.

The Commission is of the opinion that Western has failed to adequately justify the basis for this expense. The large growth rate in this expense since the time of the last case, along with Western's lack of support for the basis, leads the Commission to the conclusion that TAE may arbitrarily assign costs to Western, and that Western has little choice but to accept the allocation and pay the cost. The Commission feels that it is unfair to

---

10 T.E., pages 44-45.

11 Ibid.

12 Response to the Commission's Second Information Request, Item No. 7.

Western's ratepayers for arbitrarily assigned costs such as these to be included in their rates.

The Commission will therefore allow only the amount of corporate allocation fee included in the last case, adjusted for inflation. This results in an allowed annual corporate allocation fee of $307,452, a reduction of $40,548 from the test year amount.[13]

The Commission hereby notifies Western that in future rate proceedings the intercompany transactions will be closely scrutinized and further increases in the corporate allocation expense will not be allowed without thorough support and documentation. The Commission expects to see documentation and analyses justifying the level of allocation and to show tangible evidence of both the necessity to the Kentucky ratepayers of the services provided by TAE and the reasonableness and tangible cost-benefit relationship of the individual expenses allocated.

13

August 1986 CPI-U Index	328.6%
December 1983 CPI-U Index	÷ 303.5%
Inflation Rate	8.3%
December 1983 Monthly Fee	$ 23,657
	X 1.083
Adjusted Monthly Fee	$ 25,621
	X 12
Allowed Annual Corporate Allocation	$307,452
Test Year Actual	<348,000>
ADJUSTMENT TO OPERATING EXPENSES	$<40,548>

Rate Case Expense

Western proposed an adjustment of $44,583 to Regulatory Commission Expense to reflect the estimated $263,762 projected cost of this case amortized over a 2-year period.

The $263,762 expense proposed by Western is substantially more than the Commission would expect to be incurred for a company this size. Though precisely the same facts and circumstances are never the same in any two cases or for any two utilities, by drawing analogies from the hundreds of cases it has had before it, the Commission knows approximately what the cost of a rate case for a given size utility should be. The Commission recognizes that there may be circumstances present which may require extraordinary expenses, and the Commission will certainly accept such expenses if justified and documented.

The expense proposed by Western is more than is typically incurred in even the largest rate proceedings before the Commission. The Commission has requested extensive amounts of information on this issue in an attempt to give Western an opportunity to justify the projected expense; however, the filings by Western have failed in this respect.

The most serious matter in Western's failure to justify the level of expense is the lack of detailed invoices documenting the services provided by outside parties. Most notable in this regard are the Arthur Anderson and Company ("Arthur Anderson") invoices. Arthur Anderson billed Western $160,000 for services provided in connection with this case; however, the invoices give virtually no detail as to what services were provided.[14] This lack of detail makes it impossible to evaluate the necessity and reasonableness of the services and charges, and therefore, the invoices are insufficient as documentation of the proposed adjustment. Western stated that it did not require detailed invoices as long as the amount of the billing was in line with what it expected.[15] The Commission has a similar practice in this regard and, as the billings from Arthur Anderson are greatly in excess of what would normally be expected for a rate case of this nature, will not accept as documentation the invoices provided, nor the portion of the adjustment related to the billings from Arthur Anderson.

The Commission would like to clarify exactly why it considers the billed amounts to be excessive. In its engagement letter, Arthur Anderson stated that its work would consist of the determination of the pro forma income statement for gas operations and the related exhibits and assistance to the company with the preparation of responses to data requests. The Commission has serious reservations as to whether the compilation of this data is worth $160,000 and, more importantly, in regard to the preparation of responses to data requests, whether the use of an outside consultant is even necessary. The pro forma statements provided in the application are of average complexity, and such statements are

---

14 Response to the Commission's Third Information Request, Item No. 5, and additional information requested at the hearing, Weller's Answer No. 4.

15 T.E., page 47.

compiled by many utilities without special staff or outside consultants. In any event, the Commission would expect the cost of this service to be but a small fraction of the $160,000 billing. With regard to the billings pertinent to the preparation of data requests, the Commission would be hesitant to allow recovery of those costs for rate-making purposes, and would likely have disallowed these costs on a line-item basis had detailed invoices been provided. The requests for information in this proceeding have been primarily for financial and other information which should be readily available at the offices of Western and easily compilable. Moreover, Western has maintained computer capacity for long enough so that much of the data should be readily retrievable from computer storage. And finally, Western has had enough experience with filing cases before the Commission that much of the information requested, i.e., the first information request, is "standard" in nature and should require little or no outside assistance to formulate responses.

The foregoing is to be in no way a suggestion that the compensation for Mr. Greable's testimony should not be included as part of the rate case expense. To the contrary, Mr. Greable's testimony was most beneficial and the costs associated with that would have been considered separately if detailed invoices were available to make this possible.

The invoices provided by Consulting Services, Inc., ("CSI") were not satisfactorily detailed either. The Commission notes too that the estimated fee of $47,000 as given in the engagement letter compares with $67,311 in billings as of September 2, 1986. The invoices are not detailed enough to support a 43 percent cost overrun and the Commission has therefore limited the expense related to services rendered by CSI to $47,000, the amount of the original estimate.

The invoices provided by Western's counsel were very well documented and may serve as an example of the type of invoices that the Commission will require in future proceedings to document all rate case expenses. The Commission will allow billed amounts through September 2, 1986, as the legal portion of rate case expense; that amount was $15,338.

Western proposed to amortize rate case expense over a 2-year period based upon the average time span between the last six or seven cases.[16] Inasmuch as the time span between this and Western's last case was 3 years, the Commission considers this to be a more appropriate basis for evaluating a current amortization period. The Commission has therefore used 3 years as the amortization period in its calculation of rate case expense.

Based upon the foregoing, the Commission finds that $82,649 is the allowable expense for rate-making purposes for processing this case. Based upon a 3-year amortization period the allowable annual expense is $27,550. The test-year actual amount of $87,298 has therefore been reduced by $59,748.

16 Ibid., page 19.

Other Taxes

In its application, Western proposed an adjustment to decrease other taxes by $4,048. Based upon the settlement of the wage contract effective June 1, 1986, Western amended this amount downward by $2,572.[17] The Commission has therefore made an adjustment of $6,620 to reduce other taxes expense.

After applying the combined state and federal income tax rate of 49.915 percent to the accepted pro forma adjustments, the Commission finds that Western's operating income should be increased by $769,639 to $6,197,116.

The adjusted net operating income is as follows:

	Actual	Adjustments	Adjusted
Operating Revenues	$147,332,210	$ 2,477,972	$149,810,182
Operating Expenses	141,904,733	1,708,333	143,613,066
NET OPERATING INCOME	$ 5,427,477	$ 769,639	$ 6,197,116

RATE OF RETURN

Capital Structure

Charles A. Larson, president of CSI and witness for Western, recommended a capital structure containing 50.04 percent common equity, 37.46 percent long-term debt, 9.43 percent short-term debt and 3.07 percent customer deposits.[18] The short-term debt

17 Response to the Commission's Third Information Request, Item No. 1.

18 Larson Testimony, page 6.

component was based on a 13-month average from December, 1985, through December, 1986.[19]

James W. Freeman, Associate Professor at the University of Kentucky and witness for the AG, recommended an end-of-test-year capital structure containing 53.4 percent common equity, 40 percent long-term debt and 6.6 percent short-term debt.[20]

The Commission is of the opinion that an end-of-test-year capital structure containing 53.46 percent common equity, 40.02 percent long-term debt and 6.52 percent short-term debt is reasonable. The Commission does not include customer deposits in the capital structure and Mr. Larson has overstated Western's short-term debt ratio. A capital ratio that includes 10 months of data beyond the test year, including several months of forecasted data, is unacceptable.[21] Western's end-of-test-year capital structure is very conservative. The Commission will take this into consideration when determining the required return on common equity.

---

19 Response to the Commission's First Information Request, Item No. 15b.

20 Freeman Testimony, page 24.

21 T.E., page 273.

Cost of Debt

Mr. Larson proposed an 11.44 percent cost for long-term debt and a 9.33 percent cost for short-term debt.[22] The cost of short-term debt was based on the end-of-test-year prime rate.[23]

Mr. Freeman recommended an 11.44 percent cost for long-term debt and an 8.5 percent cost for short-term debt.[24]

The Commission is of the opinion that an 11.44 percent cost for long-term debt and an 8.5 percent cost for short-term debt are reasonable. The average prime rate for the 12 months ended August 31, 1986, was 7.9 percent.[25] An 8.5 percent cost for short-term debt will adequately compensate Western for its short-term interest expense plus required commitment fees.

Return on Equity

Mr. Larson recommended a 15.5 percent rate of return on common equity based on a discounted cash flow ("DCF") analysis, a comparable earnings analysis and a risk premium analysis.[26] Mr. Larson selected 10 utilities that he considered to be of comparable risk to Western. He then performed a DCF analysis for that group. From the 10-company group, he selected 5 exclusively gas utilities and performed a DCF analysis for that group. For

---

22 Exhibit 6, page 2.

23 Response to the Commission's First Information Request, Item No. 15a.

24 Freeman Testimony, page 26.

25 Federal Reserve Statistical Release.

26 Larson Testimony, pages 9-10.

his comparable earnings analysis, Mr. Larson looked at earned returns for a group of 20 utilities, a group of 5 gas utilities and for selected industries.[27]

The Commission is of the opinion that Mr. Larson has overstated the required rate of return on common equity for Western. In his DCF analysis of the 10-company group, Mr. Larson used a 5-year average dividend yield. Mr. Larson used a 4-year average dividend yield in his DCF analysis of the 5-company group. However, the average dividend yields have been declining since 1982 and at the time of the hearing, the average dividend yields were less than 6.25 percent.[28] Clearly, Mr. Larson's average dividend yields are not sensitive enough to current market conditions and a lower expected dividend yield is appropriate.

Mr. Larson included a 5 percent flotation cost adjustment in his DCF determined return on equity. Mr. Larson argued that a flotation cost adjustment was necessary even though Western does not sell common equity publicly.[29] The Commission remains unconvinced. Western's ratepayers should not be required to pay for flotation costs that were not incurred by the company. Mr. Larson's flotation cost adjustment contributes to the overstatement of Western's required return on equity.

---

27 Ibid., pages 16-17.

28 T.E., pages 184-186.

29 Larson Rebuttal Testimony, page 9.

A comparable earnings analysis can provide a useful check of the required rate of return on equity. However, the Commission is not convinced that simply looking at the earned returns of unregulated industrial firms, without making adjustments for risk differences, as Mr. Larson has done, is appropriate. Similarly, Mr. Larson's 20 selected utilities are primarily electric and telephone utilities.[30] Again, Mr. Larson looked at earned returns without making any adjustments for risk differences between gas, electric and telephone utilities. The Commission also notes that earned returns on equity do not necessarily equate to expected or required returns on equity. As an example, the average earned return on equity for Mr. Larson's 5-company group was only 9.6 percent in 1983.[31]

The Commission also has reservations regarding the validity and usefulness of Mr. Larson's risk premium analysis. The spread between the expected return on equity and the yield on bonds can be volatile over time and is difficult to quantify.

Mr. Freeman recommended a 12 percent rate of return on common equity based on a DCF analysis, a comparable earnings analysis and a risk premium analysis.[32] Mr. Freeman performed a DCF analysis for the Moody's 9 Gas Distribution Companies. For his comparable

---

30 Larson Testimony, Exhibit 1, page 16.

31 Ibid., page 15.

32 Freeman Testimony, page 38.

earnings analysis, Mr. Freeman looked at earned returns for 40 industries.[33]

The Commission is of the opinion that Mr. Freeman has understated the required rate of return on common equity for Western. In his DCF analysis, Mr. Freeman used an 8 percent average current dividend yield. Messrs. Larson and Freeman both erred in their applications of the DCF model. The DCF model calls for an expected dividend yield rather than a current dividend yield.

In its brief, the AG stated that the current dividend yield rather than the expected dividend yield was appropriate because the Moody's 9 Gas Distribution Companies decreased their dividends almost 10 percent from September 1985 to September 1986.[34] However, the Commission notes that if financially distressed NICOR, Inc., is removed from the average, the average dividend increases by approximately 7 percent from September 1985 to September 1986.[35] Clearly, the AG's argument against an expected dividend yield is incorrect. By using a current dividend yield rather than the appropriate expected dividend yield, Mr. Freeman has understated the DCF determined cost of equity.

---

33 Ibid., page 31.

34 Brief of the AG, page 4.

35 The Value Line Investment Survey, July 11, 1986, and The Wall Street Journal, September 1985 through September 1986.

Mr. Freeman estimated a 3.5 to 4 percent growth component for his DCF analysis.[36] The Value Line Investment Survey estimated a 5.2 percent average earnings growth rate for the Moody's 9 Gas Distribution Companies.[37] The Commission is of the opinion that Mr. Freeman's growth component is too low.

The Commission also has reservations regarding Mr. Freeman's comparable earnings analysis. He has looked at the earned returns of a large, diverse group of mostly unregulated firms. The Commission is inclined to agree with Mr. Larson that many of the firms included in Mr. Freeman's comparable earnings analysis are in poor financial condition.[38] As stated previously, earned returns on equity do not necessarily equate to expected or required returns on equity. Firms used in a comparable earnings analysis must be selected with care and appropriate adjustments for risk differences must be made. The Commission is of the opinion that the extreme diversity and the questionable financial condition of some of the firms has diminished the reliability and usefulness of Mr. Freeman's comparable earnings analysis.

Finally, the Commission has reservations regarding the validity and usefulness of Mr. Freeman's risk premium analysis. His risk premium analysis suffers from the same flaws as does Mr. Larson's.

---

36 Freeman Testimony, Exhibit 1, page 16.

37 T.E., page 225.

38 Larson Rebuttal Testimony, page 8.

In its brief, the AG stated that deflation has occurred for several months in 1986.[39] Current economic conditions are always considered when determining the appropriate rate of return on equity. However, the Commission notes that the annualized rate of inflation (as measured by the CPI-U) has never been negative in 1986 or during the test year.[40] Therefore, after considering all of the evidence, including current economic conditions, the Commission is of the opinion that a range of returns on equity of 13.25 to 14.25 percent is fair, just and reasonable. Capital costs have been declining as reflected in the high market to book ratios of the Moody's 9 Gas Distribution Companies.[41] This range of returns also reflects Western's highly conservative capital structure. A return on equity in this range will not only allow Western to attract capital at reasonable costs to insure continued service and provide for necessary expansion to meet future requirements, but also will result in the lowest reasonable cost to the ratepayer. A return on common equity of 13.75 percent will allow Western to attain the above objectives.

Rate of Return Summary

Applying rates of 13.75 percent for common equity, 11.44 percent for long-term debt and 8.5 percent for short-term debt to the capital structure approved herein produces an overall cost of

---

[39] Brief of the AG, page 3.

[40] Bureau of Labor Statistics, Consumer Price Index.

[41] T.E., pages 186-187.

capital of 12.48 percent. The additional revenue granted herein will provide a rate of return on net investment of 10.42 percent. The Commission finds this overall cost of capital to be fair, just and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that Western needs additional annual operating income of $882,202 to produce a rate of return of 13.75 percent on common equity based on the adjusted historical test year. After the provision for state and federal income taxes there is an overall revenue deficiency of $1,761,410 which is the additional amount of revenue granted herein. The net operating income required to allow Western the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $7,079,318. This level of operating income will provide a rate of return on net original cost of 10.42 percent and an overall return on total capitalization of 12.48 percent.

The rates and charges in Appendix A are designed to produce gross operating revenue of $151,571,592, which reflects the roll-in of all purchased gas adjustments approved through Case No. 8839-DD.

RATE DESIGN AND REVENUE ALLOCATION

Western proposes to combine rate classes G-2 and G-3 and adjust the rates charged to those calculated in its cost of service study. The Commission prefers a more gradual transition to cost-based rates than Western has proposed, and, as iterated herein, has some objections to Western's particular cost of service study. We are, therefore, of the opinion that the first move toward cost of service rates will be better achieved by maintaining the current rate structure, and adjusting the revenue allocation so that all of the approximately $3,565,000 difference between normalized and proposed operating revenues is allocated to the G-1 rate class. Further, approximately $1,846,000 should be subtracted from the revenue requirements borne by the G-2 and G-3 rate classes. This will result in lower commodity and transportation rates for these customers. Approximately $50,000 of the increase will be recovered through higher reconnection and insufficient funds charges.

The Commission's denial of Western's proposed rate structure includes the proposed demand charge to be instituted for the proposed combination G-2 rate class. The Commission feels that to level a demand charge solely on users of firm service is to ignore the benefits of reliable supply to interruptible customers that purchase large quantities of gas with few incidences of interruption. Until Western makes a realistic assessment of the interruptible customers' benefit from demand on an annual basis, adjusted, of course, for the risk of interruption, the Commission will not approve a demand charge for another rate class.

In considering Western's proposals for increases in customer charges and fees, the Commission again prefers to adhere to gradualism and continuity in rate-making. The increase in the G-1 residential customer charge from $1.93 to $5 is too abrupt and extreme a change; in order to avoid rate shock and yet move in the direction of cost of service, this charge should be raised to $3.

The charge for non-residential G-1 customers should be raised from $4.53 to $8. Because the present rate structure is being retained, there will be no customer charge approved for rates G-2 or G-3. Of the fee increases proposed, the increase in the insufficient funds charge from $5 to $10 appears reasonable. Increasing the reconnect charge to $25, however, is disproportionate with the approved residential customer charge increase; the reconnect charge should be raised to $20. As in the case of the customer charge, this will move toward a cost-based charge. A $20 charge should provide a sufficient economic disincentive for customers who go on and off the system frequently.

Tony Martin, who represented the intervenor, Eska Coats, proposed that customers who are reconnected pursuant to 807 KAR 5:008, Winter Hardship Reconnection, should not be charged a $25 reconect fee. The Commission is of the opinion that a reconnect fee is an appropriate charge to such customers. However, the addition of a reconnect fee to the balance owed shall not affect the requirements of 807 KAR 5:008, Section 1(2), whereby the customer is required to pay one-third of the outstanding bill or $200, whichever is less.

Western has proposed a quarterly GCA mechanism to be used in place of its present purchased gas adjustment clause. The proposal is consistent with others filed and approved by this Commission and should be approved with two exceptions: the separate demand component and the incentive factor. As has been said previously, the demand component proposed recognizes no demand cost incurred by the company in serving interruptible customers. These customers would receive free benefits from Western's long-term contracts and residential and commercial customers would bear an unfair burden of demand costs. The incentive mechanism is also unfair because it provides only potential gain to Western with no potential loss. The Commission is of the opinion that the Order in Administrative Case No. 297[42] and the forces of competition create sufficient incentive for Western to make the most economical purchases possible. The Commission will consider future incentive mechanisms that provide for risk of loss, as well as potential gain to Western.

COST OF SERVICE STUDY

The Commission commends Western for filing a cost of service study in this case. This cost of service study is the first attempt by a gas company in the state to allocate costs based on cost causation principles. As indicated in Administrative Case No. 297, the Commission wants to have cost of service studies submitted by the Class A local distribution companies.

Intervenors in this case raised questions about the large shift of costs to the residential and commercial customers. The Commission also shares this concern. The Commission is not convinced these costs are justified by the principles of cost causation.

---

42 An Investigation of the Impact of Federal Policy on Natural Gas to Kentucky Consumers and Suppliers, dated September 30, 1986.

The Commission cannot fully accept the cost of service study as submitted by Western. The increase in rates for the residential and commercial customers is too large due to questionable allocation of costs.

The use of the minimum size concept in allocating distribution costs raises concerns. Although Western may consider this allocation appropriate from a strict engineering perspective the Commission does not think this allocation method distributes costs correctly among customer classes. In the opinion of the Commission an allocation method that places more weight on the volume of sales transported would be more appropriate. A volumetric allocator should have been considered to distribute the costs of the distribution system.

Volume of sales should play a larger role in the allocation of costs. Cost allocation on a strict volume basis[43] (rather than Western's method) would reveal that Western's residential customers were responsible for 33.6 percent of Western's test-year sales volumes, yet contributed 42.2 percent to long-run overhead for the same period. And, under the proposed rates residential customers would contribute 68.4 percent toward long-run overhead costs. By the same token under a volume based cost allocation, the industrial class is responsible for 47.6 percent of the system sales, yet is allocated 37.1 percent of the overhead costs for the

[43] Brief of the AG, page 11.

test year. These figures raise questions about the cost allocations to residential and commercial customers.

Use of the design day concept in allocating certain categories results in an interruptible customer receiving a free ride when he may not actually be curtailed. This study assumes that demand characteristics in system design are only the function of design to meet a single (and hypothetical) system peak design day, and allocates demand costs on that basis. (Legal Services 1st Request, No. 13).[44] Such a study is clearly the least favorable possible approach for the residential class, as it measures their contribution to demand only at that single point where it is the highest relative to other classes.

On the other hand, interruptible customers are allocated <u>no</u> demand costs for their interruptible use, because they <u>may</u> be interrupted at a time of very high demand on the system. These interruptible volumes are considerable at other times, and are provided free of any charge for the demand component of facilities that are necessary for the provision of service. The contrast in assumptions is striking. Given such basic assumptions, it is not surprising that the residential class comes out poorly in Western's cost of service study.

These adjustments would result in more representative allocation of resources over the long run. The Commission is concerned that the rates based on Western's cost allocation study would

---

[44] Brief on Behalf of Eska Coats, page 4.

result in less efficient use of resources by establishing an artificially low rate for industrial customers.

Cost of service studies in the future should include evaluation of alternative methods of cost allocation such as the "peak and average" method of cost allocation.[45] More information on the sources of data should also be included. A more detailed explanation of the assumptions used in developing the cost allocation should be submitted. It is not sufficient to say that a certain methodology has been used for years.

POTENTIAL BYPASS

The Commission has reviewed Western's study of bypass potential which looked only at payback on pipeline installation and tap-on costs. The Commission realizes that this report was generated primarily for internal use. To determine economic bypass for a customer there are a number of other variables Western should consider.

Western's study did consider the necessary pipeline size and length required to connect to the nearest interstate pipeline. The costs of equipment to tap onto the interstate pipeline were also considered.

---

45 National Regulatory Research Institute Quarterly Bulletin, Volume 7, Number 4, October, 1986, page 453.

The Commission encourages Western to do a thorough study to estimate economic bypass. Other factors that should be considered include the following:[46]

Environmental problems associated with tap-on

Comparison of bypasser connection cost with local distribution companies ("LDCs") connection cost

Estimate of fixed cost per Mcf for connection at average, and at maximum and minimum consumption

Comparison of LDCs estimated future price increases with those of bypass supplier

Current cost of gas as a percentage of product or service price

Comparison of cost of LDC gas and bypass gas as percentage of total cost

Estimate of unit cost of plant's product or service with industry average

Comparison of growth rate of the industry with growth rate for all industry or the economy

Examination of these factors along with pipeline construction and tap-on costs would give Western a more realistic estimate of bypass potential. A more realistic estimate is needed in the Commission's opinion to justify additional services targeted at keeping large customers on the system.

Western's examination of only two cost factors results in overstating the bypass potential.

---

46 National Regulatory Research Institute, The Bypass of Local Gas Distribution Utilities - How Can You Tell If It Is For Real, August, 1986, pages 18 to 20.

SUMMARY

The Commission, after consideration of the evidence of record and being advised, is of the opinion and finds that:

1. The rates proposed by Western would produce revenue in excess of that found reasonable herein and should be denied upon application of KRS 278.030.

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

3. The rates in Appendix A are the fair, just and reasonable rates for Western and will produce gross annual operating revenues of approximately $151,571,592.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A be and they hereby are approved for service rendered by Western on and after November 1, 1986.

2. The rates proposed by Western be and they hereby are denied.

3. Within 30 days from the date of this Order, Western shall file with this Commission its revised tariff sheets setting out the rates approved herein.

Done at Frankfort, Kentucky, this 31st day of October, 1986.

PUBLIC SERVICE COMMISSION

Richard D. Heman Jr.
Chairman

Vice Chairman

George N. Williams, Jr.
Commissioner

ATTEST:

Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 9556 DATED 10/31/86

The following rates and charges are prescribed for the customers in the area served by Western Kentucky Gas Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order. These rates contain all rate changes through Case No. 8839-DD.

GENERAL SERVICE RATE G-1

Rate - Net:

Base Charge	$3.00 per meter per month for residential service
	$8.00 per meter per month for non-residential service
Commodity Charge	$3.8926 per 1,000 cubic feet

Gas Cost Adjustment Clause (GCA):

The rates specified herein are subject to revision in accordance with the provisions of the GCA.

Character of Service:

Natural gas having a heat content of approximately 1,000 Btu per cubic foot (saturated basis).

Special Provisions:

Reconnection charge shall be $20.00. Charge for read-in read-out shall be $7.50.

A charge of $10.00 shall be made for each check returned for insufficient funds.

INTERRUPTIBLE SERVICE RATE G-2

Interruptible Service:

All gas used per month in excess of the high priority service shall be billed at $3.5778 per 1,000 cubic feet.

Gas Cost Adjustment Clause:

The rates specified herein are subject to revision in accordance with the provisions of the gas cost adjustment clause.

LARGE VOLUME INTERRUPTIBLE SERVICE RATE G-3

Interruptible Service:

All gas used per month in excess of the high priority service shall be billed at $3.4078 per 1,000 cubic feet.

GAS COST ADJUSTMENT CLAUSE

Applicable to:

Gas tariffs in effect for the entire service area of the company as designated in the particular tariff.

Gas Cost Adjustment (GCA):

(A) The company shall file a quarterly report with the Commission which shall contain an updated gas cost adjustment (GCA) at least thirty (30) days prior to the beginning of each quarter. The GCA shall become effective for meter readings on and after the first day of each quarter.

(B) "Quarter" means each of the four (4) three-month periods of (1) August, September and October; (2) November, December and January; (3) February, March and April; and (4) May, June and July.

Determination of GCA:

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

GCA = (EGC - BCOG) + GCAA + GCBA + RF

Where:

EGC is the expected average cost per Mcf of gas supply which results from the application of supplier rates currently in effect or reasonably expected to be in effect during the quarter, based on purchased volumes for the most recent actual 12-month period, normalized for weather, transported volumes or any other volume adjustments. Such adjustments are necessary in order for the GCA to track as accurately as possible the actual gas costs incurred during the effective quarter.

EGC is composed of the following:

(A) Expected total gas purchases at the filed rates, or reasonably expected rates, of company's wholesale suppliers of natural gas, <u>plus</u>

(B) Other gas purchases for system supply, <u>plus</u>

(C) Gas purchases from local producers at the current rate, <u>minus</u>

(D) Gas purchases expected to be injected into underground storage, <u>plus</u>

(E) Projected underground storage withdrawals at the average unit cost of working gas contained therein, <u>plus</u>

(F) Projected propane volumes used for peak-shaving at the current equivalent price per Mcf, <u>minus</u>

(G) Projected recovery of demand costs through transportation transactions, <u>plus (or minus)</u>

(H) Change in deferred gas, <u>minus</u>

(I) Company use.

BCOG is the base cost of gas per Mcf established in company's rate case effective June 1, 1986.

GCAA is the gas cost actual adjustment per Mcf which compensates for the difference between the expected gas cost and the actual gas cost for the second quarter preceding the quarter for which the most recent quarterly report is filed.

GCBA is the gas cost balance adjustment per Mcf which compensates for any under- or over-collection which has occurred as a result of prior adjustments. This GCBA will be a "true-up" account for all gas cost actual adjustments (GCAA) after the GCAA has been in effect for four quarters. The balance in this account will be divided by an estimate of sales for the succeeding three-month period in each quarterly filing.

RF is the sum of any refund factors filed in the current and three preceding quarterly filings. The current refund factor reflects refunds received from suppliers during the reporting period. The refund factor will be determined by dividing the refunds received, by the annual sales used in the quarterly filing less transported volumes. After a refund factor has remained in effect for four quarters, the difference in the amount received and the amount refunded will be rolled into the next refund calculation. The refund account will be operated independently of the GCBA and only added as a component to the GCA in order to obtain a net GCA. In the event of any large or unusual refunds, the company may apply to the Commission for the right to depart from the refund procedure herein set forth.

Gas Cost Adjustment:

Pursuant to an Order of the Public Service Commission of Kentucky.

Applicable to:

All rate schedules.

The base cost of gas (BCOG) used in the gas cost adjustment (GCA) calculation is $3.0255 per Mcf.

To each bill rendered there shall be added an amount equal to: $0.0000 per Mcf

The base rate for the future application of the purchased gas adjustment clause of Western Kentucky Gas Company shall be:

Texas Gas Transmission Corp.

	Demand-1	Demand-2	Commodity	Gas Rate
G-2	$4.50	$.1175	$2.5170	-0-
G-3	4.77	.1294	2.5419	-0-
G-4	4.96	.1388	2.5593	-0-

Tennessee Gas Pipeline Co.

GS-2	-0-		.6581/Dth	2.3587/Dth

Local Producers	-0-	-0-	2.5419/Dth