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Public Utility
Regulatory Policies
Act of 1978

Natural Gas Rate Design Study

May 1980

Economic Regulatory Administration
U.S. Department of Energy

Attachment 1

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Act of 1978**

**Natural Gas Rate
Design Study**

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**Economic Regulatory Administration
U.S. Department of Energy
Washington, D.C.**

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ATTACHMENT 1

INTRODUCTION TO COMMENTS

The comments contained in this attachment are organized in the following manner. First, comments received in response to the Notice of Inquiry of May 3, 1979, are presented. After that, comments on each document subsequently distributed to interested parties are presented.

Among the most frequent comments expressed were the following:

- (1) The public should be given the opportunity to review the final report prior to its submission to Congress.

DOE provided the public with interim study results but did not have sufficient time before the May 9, 1980 deadline to make the final report available for comment. PURPA required that outside parties be consulted in the course of the study, not necessarily that the final report to Congress be part of the consultation process.

- (2) Results based on a single computer model of only four hypothetical utility situations cannot be used for policy-making purposes for individual companies or the entire gas industry.

DOE recognizes that the model is limited in this and other respects. The report avoids drawing conclusions about specific rate structures for specific distribution companies.

- (3) There has been an unobjective treatment of traditional and economic cost rate structures. The practical difficulties and potential detrimental consequences of economic cost rates are not fully disclosed.

The report looks at the question of rate design from the standpoint of the objectives of PURPA and the concerns of the NGPA. The question of implementation guidance is beyond the scope of the study, but must be addressed in the proposals to be forwarded to Congress in November.

- (4) It is erroneous to assume that end-users, particularly residential customers, are influenced by price signals in the rate structure, as opposed to the total bill.

This frequently repeated assertion is simply not substantiated by experience in the telephone industry, the results of electric utility rate experiments, or the tenets of economic theory.

- (5) Insufficient information has been included in the report about the model's assumptions, in particular how elasticity of demand by customer class was determined.

DOE has corrected such shortcomings by including such information in the Appendices to this study.

COMMENTS
ON
MAY 3, 1979 NOTICE OF INQUIRY

UNITED STATES OF AMERICA
ECONOMIC REGULATORY ADMINISTRATION

Notice of Inquiry of the)
Department of Energy Relating)
to the Gas Utility Rate Design) Docket No. ERA-R-79-22
Study Required by Section 306)
of the Public Utility)
Regulatory Policies Act of 1978)

WRITTEN COMMENTS OF MOUNTAIN FUEL SUPPLY COMPANY

Mountain Fuel Supply Company (Mountain Fuel) is an integrated natural gas company that participates in all major facets of the natural gas business. As a distributor of natural gas, Mountain Fuel serves over 360,000 residential, commercial and industrial customers in southwestern Wyoming and most of the state of Utah.

These comments are being submitted in response to ERA's Notice of Inquiry concerning utility rate design investigations as required by Section 306 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

Mountain Fuel submits these comments in addition to those submitted by the American Gas Association (AGA), an organization to which Mountain Fuel belongs. Mountain Fuel's comments will not be duplicative of those submitted by the AGA; they are limited to issues and considerations that have not been addressed by that association's comments.

I

ADDITIONAL RATE DESIGNS AND RELATED ISSUES

PURPA requires DOE/ERA to examine, among other rate structures, the demand-commodity rate design. This rate design is subsumed by a larger class of rate structures that attempt to identify specific types of costs incurred in supplying service in order that rates will closely reflect those individual cost components.

ERA should consider, in addition to demand-commodity rates, the broader classification of multi-part rates of which the demand-commodity design is only one. This collection of rate designs would include the so-called CED rate (Customer-Energy-Demand) and the CE rate (Customer-Energy). Mountain Fuel feels that it is necessary to examine with particular care those rate designs that are oriented toward fair allocation of identifiable categories of the incurred cost components.

II

ADDITIONAL EVALUATIVE CRITERIA

Mountain Fuel feels that an effective evaluation of the merits of various rate designs would be incomplete were it to ignore the ability of rate design proposals to respond adequately to recover the costs incurred in rendering utility service. An important aspect in these considerations is the revenue and earnings stability of a utility company as they are affected by changes in rate design. Certain rate designs will cause a high degree of fluctuation in net income as sales change from normal; others are less sensitive.

From the users' point of view, Mountain Fuel also feels that adequate consideration should be given to fair allocation of total costs to different customers or classes of customers. Although this may be what ERA had in mind when it identified "the criterion of equitable rate to consumers," there should be a more explicit focus on considerations of matching the various costs incurred by users or classes of users with the rates they pay.

Mountain Fuel bases its proposal of these evaluative criteria in a rate design study on a number of rate structure attributes identified by Professor James C. Bonbright in his widely respected Principles of Public Utility Rates (Columbia Univ. Press, 1961). At page 291-92 of that work, Bonbright states that a reasonable rate design should, inter alia:

1. Yield revenue stability from year to year,
2. Fairly apportion total costs of service among the different customers, and
3. Avoid "undue discrimination" in rate relationships.

If ERA were to include the criteria of revenue and net income stability in its study, as well as consideration for cost allocations based on the incurrence of those costs among customer classes, Mountain Fuel feels that a more meaningful study of rate design alternatives would result.

III

DEFINITION OF RATES AND EVALUATIVE CRITERIA

If the broader category of rate designs indicated in section I above are to be considered by ERA, it is necessary to define clearly the cost classifications inherent in those designs. Below are listed four commonly used cost classifications, with

definitions and descriptions similar to those contained in Gas Rate Fundamentals (3d ed., American Gas Association, 1978):

1. Capacity (Demand) Costs. These include costs and expenses generally controlled by the size of plant and delivery facilities; they are responsive to the magnitude of the potential peak hour or peak day requirements. Costs on production, transmission and storage plant and associated items of expense would be included in this category.
2. Customer (Network) Costs. These costs include costs and expenses that are affected directly by the number of customers served. This would include annual costs associated with medium-sized distribution mains, services and meters necessary to connect customers, the operating expenses incident to customer accounting and other costs that are a direct function of the size of the customer group.
3. Commodity (Quantity or Energy) Costs. Commodity costs are those that vary in direct proportion to the volume of gas purchased or produced.
4. Revenue Costs. These are the expenses dependent upon the amount of revenue received, such as taxes on gross receipts, excise taxes, certain losses from uncollectable accounts and other similar items.

IV

OPPORTUNITITES FOR COMMENT

Mountain Fuel agrees with ERA that, through promulgation of the present inquiry, its statutory obligation to provide for public comment is only partially fulfilled. Mountain Fuel strongly believes that public comment should be elicited at other meaningful times in the course of ERA's proceedings. This desire must necessarily be offset with the necessity to provide an efficient process that does not result in endless rounds of comments, proposals and counterproposals.

In order to effect adequate opportunity for public comment, Mountain Fuel would propose that ERA provide sufficient advance notice of general public comment on the substantive issues of rate design prior to the drafting of its initial report to Congress. There ought to be a second opportunity for comment subsequent to a draft of rate design proposals (as required to be submitted by November 1980), in order that interested parties may

have a final opportunity to comment on ERA/DOE positions as indicated in the original report to Congress and the rate design proposals themselves.

This would allow the public to review ERA's draft proposals and to submit comments regarding those proposals prior to their submission.

Respectfully submitted,

MOUNTAIN FUEL SUPPLY COMPANY

By

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June 29, 1979

7
UNITED STATES OF AMERICA
ECONOMIC REGULATORY ADMINISTRATION

79-2212

Notice of Inquiry of the)
Department of Energy Relating)
to the Gas Utility Rate Design) ERA Docket No. ERA-R-79-22
Study Required by Section 306)
of the Public Utilities)
Regulatory Policies Act of 1978)

WRITTEN COMMENTS OF THE AMERICAN GAS ASSOCIATION

The American Gas Association is a national trade association of approximately 300 natural gas distribution and transmission companies, which provide natural gas to approximately 160 million consumers in all 50 states. A.G.A. member companies account for about 85% of all natural gas utility sales. Therefore, A.G.A. members will be directly affected by the gas utility rate design study required under Section 306 and any legislative proposals which arise therefrom. We welcome this opportunity to comment on ERA's Notice of Inquiry relating to the gas utility rate design study required by Section 306 of PURPA.¹

A.G.A. submits these comments with the specific understanding that an opportunity will be afforded for further comment on the gas utility rate design study. A.G.A. relies on this future opportunity pursuant to paragraph II.4 of ERA's Notice of Inquiry which states that such opportunity will be forthcoming. (44 Fed. Reg. at 26055) In addition, pursuant to the statutory requirements under Section 306 (b) and (d), A.G.A. respectfully reserves the right to comment on any legislative proposals regarding gas rate design which arise from the gas utility rate design study.

¹44 Fed. Reg. 26055; May 3, 1979. Unless otherwise stated, any section citations in these comments refer to the Public Utilities Regulatory Policies Act of 1978 (PURPA).

Introduction

The principal point which the A.G.A. wishes to emphasize with regard to the study of gas utility rate design at the Federal level is the extreme importance of restraint on the part of the Federal government in prescribing new rate designs for local tariffs.

A.G.A. most respectfully submits that any Federal policy initiatives resulting from this study should be limited to general statements of principle which would be implemented at the local level only to the extent appropriate under otherwise applicable state law. This would be consistent with Sections 111 and 113, dealing with electric rate design, which emphasize that the adoption of Federal rate design standards must be subject to local regulatory needs and requirements. In addition, the above assertion is supported by the discretionary nature of the Federal standards regarding gas utility termination of service and advertising set forth in Section 303. A.G.A. believes for the reasons discussed below, that this same principle must also apply to the gas utility rate design study and any legislative proposals arising therefrom.

Each gas distribution utility is obligated to render service to all consumers in its service area under rates, terms and conditions which are just, reasonable, non discriminatory and non-preferential under State laws and regulations. Pursuant to this requirement, each gas utility has on file and in effect a tariff consisting of one or more rate schedules applicable to specified classes of kinds of service and general terms and conditions applicable to all services. Each tariff is designed to take into account the supply mix of each utility and the demands of its residential, commercial and industrial customers. The balancing of supply and demand, of

course, varies from utility to utility as does each tariff which is designed to achieve this balance. In all instances, each rate schedule has been carefully reviewed by the appropriate State regulatory authority and the tariff as a whole has been found to be just, reasonable, non-discriminatory and non-preferential.

A.G.A. submits that these essential variations among gas utility tariffs make it imperative that Federally mandated additions or alterations be carefully considered. Ill-advised Federal rate designs binding on all local utilities could work financial and service havoc at the local level with greater harm to consumers than benefit. This would clearly be contrary to the purpose stated in Title III of PURPA concerning the efficient use of gas utility facilities and resources and equitable rates to gas consumers.

Summary of A.G.A. Comments and Recommendations

The first part of these comments sets forth considerations and observations regarding general aspects of the gas utility rate design study. These comments include additions to the list of evaluative criteria and an elaboration of some of the evaluative criteria specifically enumerated in Section 306.

The second part sets forth definitions to the six specific rate designs enumerated in Section 306 and those three additional rate designs which ERA identifies in the Notice of Inquiry. These definitions are followed by comments relating to certain characteristics, both positive and negative, of those rate designs.

- The additional evaluative criterion of "Equitable rates to consumers of natural gas" should not be construed as applying only to high priority users. The "equitable rates" concept should include all classes of customers, and therefore not favor one class over another beyond the extent of traditional curtailment priorities.
- The gas utility rate design study undertaken by ERA pursuant to Section 306 must reflect present market realities, and avoid creating the false impression of inexpensive energy by proposing rate designs that artificially suppress the true cost of natural gas for certain ratepayers.
- In regard to the evaluative criterion "Pipeline and distribution load factors," emphasis should be placed on the need to preserve high load factors. This emphasis would help to: maintain an industrial market which would contribute significantly to fixed cost recovery; retain load-balancing benefits provided by such market; and maintain pricing methods which do not destroy incentives for underground storage operations.
- The evaluative criterion of "Competition with alternative fuels" should reflect the "national strategic objective to reduce our dependence of foreign oil supplies", as set forth by ERA. (44 Fed. Reg. 5815; third column; January 29, 1979) Recognition of this Federal policy would help avoid fuel switching caused by rate designs which pass burdensome and disproportionately high costs of gas to low priority users.
- The gas utility rate design study should include an additional evaluative criterion which reflects the recently announced Federal policy encouraging new natural gas hookups. (Natural Gas Hook-ups: Real Resource Cost Analysis (DOE: Washington, D.C., January 23, 1979)).
- It would be uneconomical, wasteful and generally lead to higher rates if a gas utility's facilities and resources were not used efficiently. Therefore, an additional evaluative criterion should recognize the need for optimizing the efficient use of existing natural gas distribution company facilities.
- A further evaluative criterion should address the various factors attending the financial viability of the gas industry. Such factors include: the recovery of imbedded costs, a cost/benefit analysis of individual rate designs, the ability to obtain financing in order to undertake supplemental supply projects, the impact of inflation which accounts for the sharply increased costs of obtaining new natural gas supplies and replacing existing equipment, and the specific provisions in the utility's contracts with its suppliers.

- As an additional evaluative criterion, A.G.A. emphasizes the uniqueness of each gas utility tariff because each is designed to accommodate many variables peculiar to a utility's system and region. For this reason, any Federal effort to standardize rate designs would be ill-advised.
- The rate design study must be conducted on the premise that if a modification from existing rates is to be recommended by ERA, then any legislative proposal should include a gradual modification scheme.
- Insofar as ERA must provide future opportunity for public comment on the gas utility rate design study, such opportunity should be at regular intervals during the progress of the study.

Equitable Rates to Consumers of Natural Gas Should Be Construed to Include All Consumers of Natural Gas

Whatever definition is ultimately assigned to the term "equitable," the "equitable rates" purpose of Title III, to be truly equitable, must necessarily include all classes of natural gas consumers. Otherwise, attempts to promote "equitable rates" (perhaps interpreted to mean "lower rates") for one class (such as high priority users) would unfairly discriminate against remaining low priority users in the form of unjustifiably higher rates necessary to offset revenue reductions.

Indeed, perhaps the most equitable manner of determining rate design is achieved by a fair-cost-apportionment objective. This invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service. More precisely, fair-cost-apportionment enlists the procedure described as "fully allocated costs." This is the procedure wherein (a) total utility costs are based on historical plant costs and current expenses, and (b) these costs are allocated among

customer classes by applying cost responsibility factors in proportion to the relative degree to which each customer class is estimated to be responsible. The principal categories in cost allocation procedures are demand, commodity or volume, and customer cost.

The Gas Utility Rate Design Study Must Reflect Present Market Realities

A.G.A. recognizes the importance of social issues addressed by recent legislative initiatives designed to ease the burden of higher energy costs on those who can least afford these increased costs. However, these social objectives are better achieved through legislative proposals rather than utility rate designs. Rate designs are economic formula which traditionally recognize costs of providing a service and/or commodity, and are not intended to perform ameliorative social functions such as income redistribution.

Indeed, one of the major purposes behind the Natural Gas Policy Act (Pub. L. No. 95-621) (NGPA) was to recognize present energy market realities by phased deregulation of new gas and allowing prices to rise to free market levels. Such higher prices would thereby allow natural gas to assume a more realistic cost position in the energy market, while enhancing production capability and encouraging conservation.

With respect to the ERA's reference to the encouragement of equitable rates to consumers of natural gas as one of the purposes of Title III of PURPA discussed supra, and its concern with residential rates in particular, A.G.A. would point out that the implementation of incremental pricing pursuant to Title II of the NGPA must be kept in mind at all times by the ERA during its study

of gas utility rate design. Any increase in the rates of those industrial customers subject to incremental pricing beyond their alternative fuel price as the result of alterations in rate design will result in a loss of industrial load which, in turn, will necessitate an increase in the rates of remaining customers, including those who use gas to heat their homes. A.G.A. believes that the incremental pricing provisions of the NGPA protect residential customers to the maximum extent possible with regard to the rates they are charged for their natural gas.

The Evaluative Criterion of "Pipeline and Distribution Load Factors" Should Emphasize the Preservation of High Load Factors

There are three distinct benefits which arise from the presence of a high load factor in a pipeline or distribution system. One, a high load factor usually implies the maintenance of an industrial market which contributes significantly to fixed cost recovery. Two, a high load factor, along with a curtailable industrial market, accounts for load-balancing benefits that optimize pipeline and distribution facility usage in off-peak periods. (This attribute specifically accomplishes the "optimization" purpose of Title III.) Three, a high pipeline load factor implies the use of pricing methods which could retain incentives for providing underground storage to improve purchase load factors.

If a rate design fails to foster a high load factor, that design would likely have an adverse impact on service to the industrial market thereby causing fuel switching and industrial load loss. This load loss would, in effect, forfeit the above benefits afforded by the industrial market. Ultimately, all remaining

customers, including residential users, would be required to pay higher rates to cover the fixed costs formerly allocated to the industrial customers. Furthermore, in such a case there would be an increased likelihood of gas shortages during peak use periods because of the loss of the industrial load. Loss of storage incentives could prove catastrophic, if valuable energy reserves were lacking during a winter energy emergency such as the one in 1976-77.

The Evaluative Criterion of "Competition with Alternative Fuels" Should Reflect the Federal Policy to Reduce our Dependence on Foreign Oil Imports

In proposed regulations governing existing facilities under the Powerplant and Industrial Fuel Use Act of 1978 (FUA), ERA issued a policy statement to the effect that it is a "national strategic objective to reduce our dependence on foreign oil supplies." (44 Fed. Reg. at 5815; third column; January 29, 1979) In this respect, it is vitally important to the achievement of this objective that the evaluative criterion of "competition with alternative fuels" reflect this policy. As stated above, industrial load loss resulting from fuel switching (particularly to fuel oil) would cause the adverse effects sought to be avoided by this Federal policy. These effects include continued foreign energy dependence, increased balance of payments deficits and further deterioration of the dollar in the world money market.

An Additional Evaluative Criterion Should Be Included to Reflect the Federal Policy Encouraging Natural Gas Hook-Ups

So as not to inadvertently frustrate the Federal policy encouraging natural gas hook-ups, the rate design study should recognize this Federal policy in an additional evaluative criterion. (Natural Gas Hook-ups: Real Resource Cost Analysis (DOE: Washington, D.C.,

January 23, 1979)) ERA must give consideration to this policy notwithstanding the fact that one of the purposes of Title III is "conservation of energy supplied by gas utilities." This purpose is not indicative of a policy advocating hook-up moratoria and should not be construed as such.

Optimization of the Efficiency of the Use of Facilities and Resources by Gas Utility Systems Should be an Additional Evaluative Criterion

It would be uneconomical and generally wasteful not to fully and efficiently utilize the in-place capital assets, facilities and resources of gas utilities. Optimizing efficient use of utility facilities and resources would help assure continuation of positive aspects of a high load factor discussed, supra, at pages 5-6.

A.G.A. emphasizes, however, that the nature of a gas utility's load leaves very little room for improvement in this area through modification in rate design. A.G.A. submits that attempts to alter gas utility rate designs in an effort to improve peaking capability will realize little savings, will not be workable, and are unnecessary.

An Additional Evaluative Criterion Should Assess the Extent to Which a Rate Design Preserves the Financial Viability of the Gas Utility Industry

It would be shortsighted and less than a thorough analysis to study various gas utility rate designs and not include an assessment of the financial impact on the gas utility industry. The foremost concern in such assessment would be the assurance of the financial viability of a gas utility enterprise. This is particularly reflected in the study of a specific rate design's ability to permit recovery of imbedded costs.

A related issue that should be included in this evaluative criterion is a cost/benefit analysis of the various rate designs under study. Such analysis would reveal the ultimate impact of a particular rate design on the gas utility industry.

Additionally, this evaluative criterion should include an evaluation of the impact of each rate design on the utility's cost of capital, and its ability to obtain additional financing at a reasonable cost. This consideration is particularly important insofar as it affects a utility's ability to undertake major supplemental supply projects. Also, inflation must be recognized as a contributing factor to the escalating costs of replacing conventional natural gas supplies as well as replacing existing or obsolete equipment.

Finally, because the financial viability of a gas utility rests, to a certain extent, on the specific provisions of its supply contracts, this additional evaluative criterion should recognize such provisions. In particular, if a rate design causes the loss of industrial customers, a take-or-pay provision in a utility's supply contract could have a very damaging effect on that utility's financial stability.

An Additional Evaluative Criterion Must Reflect the Uniqueness of Each Gas Utility Tariff

In each case, a gas utility tariff is the result of the careful consideration of many variables which, in conjunction, provide a unique set of parameters defining that tariff. Included in these variables is the service area's weather which is important as it determines the resulting character of the customers' heating demand. Another factor contributing to the uniqueness of a tariff is the size and character of the industrial demands served by the utility and the relation of these demands to the residential and

commercial demands. In addition, the availability to a utility of SNG, LNG, and local production and storage also combine to render each utility tariff unique. ERA should be cognizant of these factors and make no effort to standardize gas utility tariffs.

If a Modification from Existing Rates is to be Recommended, ERA Should Propose a Gradual Modification Scheme

Our energy-intensive society has its economic well-being dependent to a large extent on the energy distribution system. Therefore, experimentation with pricing concepts must be carefully analyzed and evaluated in advance. Rapid implementation of a newly-conceived rate design program for the gas industry would be both imprudent and ill-advised. If ERA does recommend any rate design changes, those recommendations should be accompanied by an implementation scheme that is gradual and non-disruptive. Indeed, perhaps modification from an existing rate design is appropriate only after isolated experimentation rather than immediately implementing the new rate design for all utilities.

Further Opportunity for Public Comment Should be Afforded at Regular Intervals During the Rate Design Study

ERA should provide opportunity for further public comment at regular intervals during the rate design study and particularly when some specifically identifiable stage of progress is reached. For example, when definitions for the rate design have been proposed, notice and opportunity for comment should be provided. Because certain aspects of the study may progress at varying degrees, opportunity for

comment should come at the time of formalizing that aspect, rather than waiting for the entire study to be completed. In this manner, careful consideration can be given each part of the study as it is completed.

RATE DESIGN DEFINITIONS

Insofar as ERA specifically requested definitions for the various rate designs enumerated in Section 306 and those additional rate designs listed in the Notice of Inquiry, A.G.A. submits the following definitions. Whereas the definitions themselves are straightforward, they are followed by a general commentary beginning at page 13.

Incremental Pricing/Marginal Cost Pricing Rate Designs

As generally employed, there really is no difference. Marginal costs should properly be considered as a theoretical concept, applicable to the next therm used or conserved within a given supply framework. Incremental costs (particularly long-run) should relate to the costs associated with meeting additional blocks of demand for natural gas service on a continuing basis. It should be emphasized that the distinction, to the extent that it exists, is commonly ignored; in practice we are considering one theory of pricing, not two.

Seasonal Rate Differentials

These are gas rates which are designed to recognize cost differences between peak (winter) and off peak (summer) periods.

Demand - Commodity Rate Design

Demand-Commodity Rates (sometimes referred to as "two part-rates") are based on two categories: 1) demand, i.e., maximum demand or capacity imposed by the customer on the utility's system within a specified period, which establishes the utility's responsibility to supply; and 2) commodity charge(s) i.e., based on the volume of gas actually used.

Declining Block Rates

This is a rate schedule which reflects declining unit charges for increasing blocks of consumption.

End User Rate Schedule

These are rate schedules determined by the actual end use of the gas (i.e., space heating, water heating, industrial process, boiler use or power generation).

Volumetric Rates

These are rates which employ essentially a straight line rate based upon a constant rate per unit of gas consumed as measured on the customer's meter.

Lifeline Rates

This is a rate structure applicable to residential customers which provides for a specified block of energy use priced below the associated cost to serve. The block of energy may be priced at a flat amount for the entire block or on a per unit basis.

Inverted Rates

This is a rate schedule which provides increasing unit charges for succeeding blocks of increasing energy usage.

GENERAL CONSIDERATIONS REGARDING THESE RATE DESIGNS

Incremental Pricing/Marginal Cost Pricing Rate Designs

In the last few years, there has been an interest on the part of regulators, economists, and consumer advocates to examine and reevaluate costing and pricing theories. This has frequently involved an advocacy of incremental or marginal pricing, rather than fully-allocated or "rolled-in" pricing, on the presumption that the new procedures would restrain demand by providing replacement cost price signals to consumers, relieve price pressures on certain existing gas users, and provide for more efficient resource allocation.

Insofar as Title II of the NGPA establishes "incremental pricing," a question arises as to whether ERA-R-79-22 contemplates that particular incremental pricing scheme as a rate design for purposes of Section 306 of PURPA. The principal intent of Title II

is to protect high priority customers from increases in gas costs which will be incurred as old gas production declines and the proportion of higher cost, new natural gas grows. This protection which is only temporary as discussed, supra, theoretically arises by "incrementally pricing" large industrial boiler customers under Rule 1. Rather than the traditional notion of incremental or marginal cost pricing, this scheme is really an End Use rate design because it is in fact a selective pricing of a particular use based upon a specifically defined cost.

In summary, the gas distribution industry is opposed to marginal cost pricing for the following reasons:

- Existing rate design is founded on sound logic, is cost justified, has served the industry and its customers well, and has been found to be non-discriminatory.
- Marginal cost pricing requires long-term estimates of price elasticities, relative energy costs, and timing and quantities of supplemental supplies, all of which are subject to major questions of reliability.
- Marginal cost pricing will require of each gas company major expenditures of time and money to quantify appropriate charges. The effort will result in a rate design which may not be any better than that currently in effect.
- Finally, there is still no agreement on how marginal cost shall be measured; and translated into workable rate schedules.

Seasonal Rate Differentials

The concept is well-recognized and has been used by gas distributors for many years in establishing interruptible and off-peak rates, as well as summer-winter differentials for residential service. Seasonal service rates are usually offered in the season of reduced demand for purposes of improving system load factor and correlating load profile with supply

profile because the rates are designed to encourage use of gas in off-peak periods. Therefore, a utility can optimize the use of its system with resultant benefits reflected in rate levels. These beneficial rate levels offer, in addition, some assurance that revenue requirements will be met thereby saving the costs of seeking outside capital.

In regard to pipelines, a "summer-winter" rate can also be found. This type of rate charges a higher price for all gas taken in excess of base loads or average daily delivery established during the summer period. Base load gas is priced at a lower level, and sometimes at commodity charges only.

Demand-Commodity Rate Design

Demand may be determined by metering or, to a lesser degree, by determining a customer's connected coincident load which may result from use of gas consuming appliances or equipment. Incorporating demand into a rate schedule generally requires complex metering and recordings which entail the use of much more costly meters and billing methods. For this reason, demand rates are usually reserved for large use customers.

A rate schedule feature sometimes associated with demand rates is the "ratchet clause." This provides that billing for the demand component cannot be less than a stated percentage of the customer's maximum demand during a previous period, usually the twelve months ending with the current billing month. The purpose of this feature is to require the customer to continue to pay the fixed costs incurred by the utility in maintaining adequate facilities ready to serve the customer.

Specifically, in the case of pipeline rates, the rates for firm gas (i.e., gas sold under a contract anticipating no interruptions) take the demand-commodity form in the majority of cases. The minimum monthly charge in this rate form is the demand charge multiplied by the contracted demand or percentage thereof.

The pipeline industry primarily uses the term "demand-commodity rate," however, distribution gas utilities also use this rate form for some of their large industrial or commercial customers.

Another "two-part" rate currently used by distribution companies is a rate schedule consisting of a monthly "customer" charge and a separate "volumetric" commodity charge based on the customer's actual gas consumption. The customer charge includes certain fixed costs incurred by the utility to serve a particular customer class whether or not the customer uses gas with the balance of the fixed and variable costs assigned to the commodity charge and collected based on actual consumption.

Declining Block Rates

Essentially, this rate design enlists two or more successive blocks of use, each with declining prices. Billing is according to the amount of gas a customer uses in each successive block at the rate applicable to that block. The costs of the amount of gas used per block are added to arrive at the bill total. This rate offers stabilized customer billing by providing a buffer against extraordinary billing charges due to the vagaries of, and fluctuations in, seasonal requirements.

Depending on the "steepness" of the declining charge (ratio between charges in the first and last blocks), varying proportions of fixed costs are recovered in the initial blocks. The cost to the company of providing additional units of gas to an individual customer are lower, thus justifying lower commodity rates in the ensuing blocks.

Because of its simplicity the declining block rate is the most widely accepted form of rate in common use. However, the rate is desirable for reasons other than its simple application. This rate, more readily than others, provides a mechanism for the recovery of customer, demand and commodity costs. Moreover, when properly designed, the declining block rate schedule helps to stabilize a utility's revenue requirements by including most of the customer and demand costs in the initial blocks.

End User Rate Schedule

The rate schedule is more accurately named an "End Use Rate Schedule" because it is designed to reflect a particular type of natural gas use, not the type of user.

Generally, these schedules are intended to address specific uses in order to achieve specific marketing objectives. An example of such objective is to fill summer demand "valleys" by using load influencing rates such as those encouraging use of gas air conditioners.

Volumetric Rates

Volumetric rates are straight (unblocked) rates and are sometimes used for certain special services by pipelines, such as "non-firm" and optional small volume service. In the past, gas

distributing utilities used straight line rates to bill for water heating, cooking and refrigeration. These rates are quite simple and are appropriate where significant homogeneity of usage exists among all customers served on the rate.

Another characteristic of volumetric rates is that the cost of service is directly proportional to, and highly correlated with the volume of usage. For this reason, volumetric rates, applied to all classes of customers, would not accurately reflect fully allocated costs if there were a lack of homogeneity among the classes served. Therefore, such use of volumetric rates would preclude fair-cost-apportionment and realization of cost-responsibility.

In this respect, volumetric rates have the potential for inducing industrial load loss with a resultant forfeiture of the benefits afforded by the industrial market, viz., a significant contribution to fixed cost recovery, a high load factor optimizing pipeline and distribution facility usage, and a high load factor accounting for underground storage incentives because of favorable pricing methods.

Lifeline Rates

The underlying premise of lifeline rates is that every residential customer should receive an amount of gas service, at a reduced rate, adequate to meet basic human needs defined differently by various advocates. The rate is designed to make such service available at a pre-determined rate that is priced below all other residential usage. A basic assumption of this rate design is that poor customers use only small volumes while the affluent use more, an assumption which has yet to be verified.

The revenue reduction resulting from lower prices in the initial blocks must be recovered by increasing the charges in later residential blocks. If this revenue deficiency is recovered from non-residential and low priority users, again the possibility of load loss and the forfeiture of benefits accompanying an industrial load arises.

Inverted Rates

"Inverted rates" are also known as "reverse blocking" or "graduated rates." Such a rate design is advocated as a means of discouraging usage through price elasticity. If load loss is to be prevented, care must be taken to assure that the tail block rate is not in excess of the alternate fuel cost. However, because this rate form is completely at variance with cost causation and because subsequent blocks carry higher charges than initial blocks, the potential for load loss and the ensuing problems arise. This would be the case particularly in the instance of a utility with a high residential heating load experiencing an unusually warm winter.

Conclusion

Because of the inherent complexities of rate designs and the manifest opportunities for some designs to adversely affect both high and low priority customers and the gas utility industry, we stress that ERA engage in a cautious, thorough, and well-reasoned examination of gas utility rate designs. As the ERA well knows, the A.G.A. is thoroughly committed to the stated purposes of Title III of PURPA: the conservation of energy, the optimization of the efficient use of facilities, and the encouragement of equitable rates for natural gas consumers. To these ends, the A.G.A. desires

and stands ready to cooperate with the ERA to the fullest extent possible with regard to its ongoing study of gas utility rate designs.

Respectfully submitted,

THE AMERICAN GAS ASSOCIATION

By
George H. Lawrence, President

Michael J. Zimmer, Assistant
General Counsel and Director,
Legislative and Regulatory
Affairs

Further Communications with respect to these
comments should be addressed to:

Michael J. Zimmer, Assistant General Counsel and
Director, Legislative and Regulatory Affairs
or

Thomas C. Martin, Legislative and Regulatory Affairs
Division
American Gas Association
1515 Wilson Boulevard
Arlington, Virginia 22209
703-841-8464

Dated: July 2, 1979

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

Gas Utility Rate Design Study;)
Responsibilities Under Public)
Utility Regulatory Policies Act)
of 1978)

COMMENTS OF THE PEOPLE
OF THE STATE OF CALIFORNIA
AND THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Pursuant to the Notice of Inquiry (44 Fed. Reg. 26055 (1979)) issued by the Department of Energy (DOE) in this proceeding the People of the State of California and the Public Utilities Commission of the State of California (California) herewith submit their comments.

California has reviewed the rate designs specified in the Public Utilities Regulatory Act of 1978 (PURPA) and the additional rate designs specified by the Energy Regulatory Administration (ERA) for inclusion in rate design study proposed in the Notice. We believe that the list is a complete one, sufficient at least, for the conduct of a comprehensive gas utility rate design study as intended by PURPA.

California notes, however that in identifying additional evaluation criteria, ERA has focused on one of the purposes of Title III of PURPA, to encourage equitable rates to consumers of

natural gas. California is of the view that the other two purposes of Title III, those of conservation and optimization of efficiency in use of gas facilities and resources, should also be explicitly considered in the evaluation of alternative rate designs.

The Notice of Inquiry requests suggestions on the subject of opportunities for public consultation and comments on the rate design study. The gas utility rate design study which is about to be undertaken will in all probability form the basis for future DOE policy. Gas utility rate design is a subject of significant importance to state regulatory authorities. California therefore urges that representatives of regulatory bodies be afforded an opportunity to provide meaningful input relative to the design of the study as well as during the course of the study, rather than subsequent to the publication of proposed findings.

One potential mechanism for insuring a sufficiency of state participation could be the establishment of an advisory committee which would meet on a regular basis with the ERA. Members of the advisory committee could be designated by the chairman of the National Association of Regulatory Utility Commissioners (NARUC) Ad Hoc Committee on the National Energy Act. Such an advisory committee should be offered the opportunity to affect the conduct of the study by providing technical assistance and consultation prior to the drafting of a proposed work plan. Limiting such a committee to comments on completed activities would not, we believe, result in an effective state contribution. The advisory committee should be able to participate at each significant step in the study.

There are other mechanisms for insuring that an adequate degree of state input is available to the ERA. For example, with assistance from the National Regulatory Research Institute the ERA could conduct surveys of state commission rate design procedures. Also, workshops or informal meetings could be held with state commission staff. California proposes that all such mechanisms be investigated prior to the finalization of the study design. California supports ERA in this endeavor and would welcome the opportunity to assist in any manner.

Respectfully submitted,

Janice E. Kerr

J. Calvin Simpson

Lawrence G. Garcia

Attorneys for the People of the State
of California and the Public Utilities
Commission of the State of California

June 29, 1979

WISCONSIN PUBLIC SERVICE CORPORATION

P.O. Box 700, Green Bay, Wisconsin 54305

June 13, 1979

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street, N.W.
Docket ERA-R-79-22
Washington, DC 20461

Gentlemen:

We have the following general comments regarding the Gas Utility Rate Design Study - Notice of Inquiry:

1. Our service territory encompasses 10,000 square miles of Northeastern Wisconsin and Menominee, Michigan. Annual heating degree days range from 7600 to 9600. The rapid rise of natural gas prices has caused our residential space heating customers to reduce their consumption up to 20%. Our commercial and industrial customers have also substantially reduced their use and some industrial customers have converted to other fuels. We expect the continued increase in price to cause such reduction in use to continue. To now develop proposals and legislative recommendations to improve gas utility rate design and encourage conservation of natural gas seems redundant.
2. Equitable rates to consumers of natural gas requires that each class of customers should bear its portion of the utility's revenue requirement as determined by embedded cost of service. Changing revenue from one class to another, or causing one class of service to bear the higher deregulated prices as the pending incremental pricing proposal will do, is not equity but discrimination.
3. Our company must have clear guidelines in order to carry out its function as a natural gas utility. Such regulations are presently issued by our state commission. To now impose a different or conflicting federal regulation will compound the energy problem by creating confusion as to what regulation is, or will be, in effect. Some of our industrial customers have already reacted to the confusion over gas supply and price by converting their energy requirements to another fuel. As more customers convert to other fuels, other rates will have to be increased by the amount of the costs that were recovered by the lost sales.

Department of Energy
Page 2
June 13, 1979

4. There has been recent stress on the social aspect of rate design, particularly through lifeline or inverted rates. Natural gas utilities should not have to assume the role of the welfare agencies, nor should existing rate payers have to bear the added cost burden of such welfare administration. Existing welfare agencies who already have the required data should handle this problem, possibly through energy stamps.
5. Critical to rate design is a cost of service analysis. An embedded cost of service study should be utilized to not only determine what the utility's total revenue requirement should be, but what share of the total revenue each class should bear. The assignment of such embedded cost to customer, demand, and commodity or energy components will indicate what the rate design should be. In the final tuning of rate design, the marginal cost may be considered.

It is our opinion that the application of innovative and/or exotic rate designs, such as lifeline and inverted, or pricing schemes of incremental/marginal to the total revenue required, have little or no impact on how a customer views his bill; that is, such customer looks at his total bill. In our service territory, where 80% or more of the residential consumption is utilized for space heating and the temperature may be -10°F. to -30°F., the consumer is concerned about keeping warm, not what the next unit of consumption will cost.

The already rapid rise in natural gas prices and the forthcoming continued rise due to deregulated price, all of which flow through to our retail business via the purchased gas adjustment clause, has been, and will be, incentive for the consumer to reduce consumption without the helpful devices contemplated in this study.

6. It appears that Section 141, Title I - Subtitle E, and Section 603, Title VI - Miscellaneous Provisions, will hold state commission hostage to federal fiat, through the availability of funds for training and/or other assistance. If such funds are to be made available to the state agencies, no strings should be attached.
7. Opportunity for public comment on the study required by Title III, Section 306, should be afforded after the study is completed, but before it is submitted to Congress.

Sincerely,

A. E. Pearson
Assistant Vice President-
Rates and Budgets

AEP/MES/eal

LAWRENCE G. SPIELVOGEL, INC.

CONSULTING ENGINEERS

WYNCOTE HOUSE • WYNCOTE, PENNSYLVANIA 19095 215-887-5600

May 25, 1979

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street, N.W.
Docket: ERA-R-79-22
Washington, D.C. 20461

Re: Gas Utility Rate Design Study

Gentlemen:

In accordance with your notice in the May 3, 1979 Federal Register I would like to suggest that you add the issue of prohibition of master metering to the issues that you will be considering in this study.

There is some controversy surrounding the prohibition of master metering for electricity as well as some concern as to whether or not it may be cost and/or energy effective. Much the same arguments can be made for gas master metering.

To somewhat complicate this matter the discussion on prohibition of master metering for electricity has centered around multifamily dwelling units as opposed to all other classes of customers. Therefore any study should look at the classes of gas customers and the way they might be impacted by a prohibition on master metering.

Very truly yours,

LAWRENCE G. SPIELVOGEL, INC.

L. G. Spielvogel, P.E.

LGS:bhs

79226

BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION
WASHINGTON, D.C.

Gas Utility Rate Design Study;
Responsibilities Under Public
Utility Regulatory Policies Act
of 1978

:
:
: Docket No. ERA-R-79-22
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:

COMMENTS OF THE
UNITED STATES BREWERS ASSOCIATION, INC.

Communications with respect to
this document may be sent to:

Mr. Henry B. King
President
U.S. Brewers Association, Inc.
1750 K Street, N.W.
Washington, D.C. 20006

James W. Riddell, Esq.
John E. Gillick, Esq.
Dawson, Riddell, Taylor,
Davis & Holroyd
723 Washington Building
Washington, D.C. 20005

July 2, 1979

BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION
WASHINGTON, D.C.

Gas Utility Rate Design Study;
Responsibilities Under Public
Utility Regulatory Policies Act
of 1978

:
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: Docket No. ERA-R-79-22
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COMMENTS OF THE
UNITED STATES BREWERS ASSOCIATION, INC.

By notice published in the Federal Register on May 3, 1979 (44 Fed. Reg. 26054-55), the Economic Regulatory Administration ("ERA") has solicited comments on issues related to the gas utility rate design study required to be undertaken by the Department of Energy pursuant to Section 306 of the Public Utility Regulatory Policies Act of 1978. In accordance with that notice, the United States Brewers Association, Inc. (hereinafter "USBA" or "U.S. Brewers Association") hereby submits the following comments.

In summary, these comments (1) identify the interest of the United States Brewers Association, Inc. in this proceeding, (2) urge that the Economic Regulatory Administration consider the impact of the various rate designs and related gas utility issues on agricultural users of natural gas, and (3) request that additional opportunities for public comment be provided as the content of this study becomes more definitive.

The United States Brewers Association, Inc., is composed of companies engaged in all phases of the production of malt beverages. Its members employ almost 40,000 persons directly, and over 500,000 persons in the United States are involved in beer production and distribution and related industries. Overall, the making of malt beverages in the United States is a 7 1/2 billion dollar industry, contributing approximately 1.4 billion dollars per year in excise taxes to the Federal government and another 900 million dollars per year in such taxes to state governments.

On March 1, 1979, the Agriculture Department published an interim final regulation which, inter alia, certified the use of natural gas by establishments classified in SIC Nos. 2082 (Malt Beverages) and 2083 (Malt) as an essential agricultural use for purposes of establishment of curtailment priorities under the Natural Gas Policy Act of 1978. 44 Fed. Reg. 11518. On May 17, 1979, the Agriculture Department published a final regulation which, inter alia, certified "100% of Current Natural Gas Requirements" as the natural gas requirements for each essential agricultural use establishment. 44 Fed. Reg. 28782. Finally, the Federal Energy Regulatory Commission has published a proposed regulation implementing the incremental pricing provisions of the Natural Gas Policy Act of 1978 in which "essential agricultural use" of natural gas for boiler fuel would be exempt from incremental pricing. Thus, the members of the U.S.B.A. have an important interest in policies affecting natural gas pricing and related issues.

Turning to the issues raised in the notice, the U.S.B.A. intends to focus its comments at this time on the evaluative criteria with respect to which the rate designs and related issues are to be analyzed.^{1/} In that regard, our principal concern is that the various gas utility rate designs considered in the study be evaluated in a manner consistent with the objectives of the Natural Gas Policy Act of 1978, particularly the specialized treatment afforded agricultural users of natural gas by that Act.

As ERA is aware, the Congress, in enacting the Natural Gas Policy Act (one of the five laws comprising the so-called National Energy Act (P.L. 95-617-21)), established, inter alia, specialized pricing and curtailment policies for agricultural uses of natural gas in order to avoid increases in food prices (see Sections 206 & 401 of the NGPA). Indeed, the portion of the Conference Report dealing with curtailment priorities reflects this important policy consideration in the following manner:

"The conferees intend that the authority to restrict curtailment priority by determining that alternative fuels are economically practicable and reasonably available be utilized only in cases where it is clear that both tests are met. One of the reasons for imposing such a requirement is to prevent

^{1/} As discussed infra, the U.S.B.A. believes that the public should be afforded continuing opportunities for comment as the parameters of the ERA study become more specific, and we would expect to provide more definitive comments on the rate design issues at that time.

unnecessary increases in the cost of food in this country. The Commission determination that an alternative fuel is 'economically practicable' shall not include a requirement to switch to high cost alternatives. That is not what the conferees consider to be 'economically practicable'." H. Rep. No. 95-1752, 95th Cong., 2d Sess. 114 (1978).

Thus, it is clear that the Congress was concerned with the impact of increased natural gas prices on the cost of food. Consequently, we believe that it is particularly important that ERA, in analyzing the rate designs and related issues in this study, specifically evaluate the impacts of these designs on the cost of natural gas to agricultural users. Towards that end, we would suggest that ERA work closely with the Department of Agriculture in order to assure that these impacts are fully identified and evaluated.

As alluded to earlier, we urge that the ERA, between now and May 1980, provide additional opportunities for public comment on this study as the various issues become more clearly defined. In this regard, we believe that the quality of comments received in proceedings such as this varies directly with the specificity of the proposals being evaluated. Accordingly, we would urge that the ERA, as soon as possible after the conclusion of the period for comments herein, prepare a summary and analysis of the comments received, develop its own preliminary analysis of these issues, and submit these materials for additional comments.

We appreciate the opportunity to provide these comments,
and look forward to participating in this proceeding in the
future as the parameters of the study become more definitive.

Respectfully submitted,

s/ James W. Riddell

James W. Riddell

s/ John E. Gillick

John E. Gillick

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Attorneys for the
United States Brewers
Association, Inc.

July 2, 1979

515 South Flower Street
Mailing Address: Box 2679 - T.A.
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Telephone 213 486 3210

792217

N. M. Smirlock
Manager
Governmental Controls Coordination

June 27, 1979

Department of Energy
Office of Public Hearing Management
Room 2313, Docket No. ERA-R-79-22
2000 M Street, N.W.
Washington, D.C. 20461

Re: D.O.E. DUTIES, RESPONSIBILITIES AND AUTHORITIES
UNDER TITLE III SECTION 306 OF THE PUBLIC UTILITIES
REGULATORY POLICIES ACT OF 1978

Gentlemen:

Atlantic Richfield Company is pleased to submit these comments in response to the Notice of Inquiry issued April 30, 1979. We support the stated purposes of Title III as necessary for the responsible, economic, efficient utilization of our natural resources. We also recognize that completion of the rate design study and the development of proposals for improvement are not optional undertakings. However, we do have some concerns about the approach to the problem.

We believe the goals of Title III can be achieved most effectively by allowing each utility to work out a rate design system for its particular customer mix and other factors unique to the utility. This should be encouraged through development of rate design system principles which, if followed, would ensure that the utility moves toward meeting the goals. The creation of mandatory rate design systems to be imposed on utilities and state rate regulating agencies might result in less than optimum conservation and use of facilities by some utilities. This in turn would lead to requests for relief, applications for exceptions, and all of the other wasteful effects of detailed regulation. On the other hand, the application of more flexible principles would allow state agencies and utilities an opportunity to work out unique problems.

Department of Energy
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June 27, 1979
Page 2

We believe the paramount consideration should be to ensure maximum conservation under circumstances where every consumer pays his fair share of the cost, including appropriate returns on investment. No consumer should be expected to pay more than cost while some other consumer enjoys a free ride.

With regard to additional opportunities for public comment, we believe that the usual public hearings should be used to obtain public reaction to principles developed in smaller, less informal, meetings with interested utilities and state regulatory authorities.

We hope these comments are helpful to your consideration of this matter.

Yours very truly,

N. M. Smirlock

BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION
DEPARTMENT OF ENERGY

Comments Of Consolidated Edison Company Of
New York, Inc. On The Gas Utility Rate Design
Study Required By The Public Utility
Regulatory Policies Act Of 1978

These comments are submitted by Consolidated Edison Company of New York, Inc. in response to the Economic Regulatory Administration's Notice of Inquiry, published in the Federal Register of May 3, 1978, seeking comments on its duties, responsibilities and authorities under the Gas Utility Rate Design Proposals provision in Section 306 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Pub. L. 95-617 (Nov. 9, 1978).

Section 306 of PURPA requires the Secretary of Energy, by May 8, 1980, to study and report to Congress on gas utility rate design, including in the report an assessment of the effects of nine particular factors,* both separately and in combination, on six identified areas of concern, which ERA has identified as the study's "evaluative criteria".**

* The nine factors, comprised of rate design and related issues, are: incremental pricing; marginal cost pricing; end user gas consumption taxes; wellhead natural gas pricing policies; demand-commodity rate design; declining block rates; interruptible service; seasonal rate differentials; and end user rate schedules (Section 306(a)(1) of PURPA).

** The six evaluative criteria are: natural gas pipeline and local distribution company load factors; rates to each class of user, including residential, commercial, and industrial users; the change in total costs resulting from gas utility designs (including capital and operating costs) to gas consumers or classes thereof; demand for, and consumption of, natural gas; end use profiles of natural gas pipelines and local distribution companies; and competition with alternative fuels (Section 306(a)(2) of PURPA).

Based on this study, the Secretary is required to develop proposals to improve gas utility rate design and encourage gas conservation. In its Notice of Inquiry, the ERA stated that it had determined to add three rate design factors to the nine factors required to be studied by the Act (volumetric rates, lifeline rates and inverted rates), and to add one additional evaluative criterion, namely, equitable rates to consumers.

Con Edison recognizes the far-reaching importance of this study to the gas industry and, consistent with that recognition, we would like to emphasize our desire to be afforded the widest possible opportunity to participate in the conduct of this study. We would appreciate the opportunity to comment on any drafts of the report to be prepared.

Con Edison believes that it is important to consider the various gas utility rate designs in the context of overall national energy policy. For example, some gas utility rate designs, while resulting in conservation of gas, may result in increased utilization of other fuels such as oil. This would be contrary to national energy policy, as one of the overriding objectives of that policy is "to reduce dependence on foreign oil and vulnerability to supply interruptions" (Executive Office of the President, The National Energy Plan, p. IX (April, 1977)).

Conversely, some gas utility rate forms (such as interruptible rates, for example) may result in increased use of gas and reduced use of other sources of energy. For example, some gas rate designs might induce customers to shift from using electricity to using gas. In that event, electric utility rates would go up as the fixed costs of electric utilities would be spread over a smaller customer base. We believe that any such impact should be carefully considered.

Finally, some changes in gas utility rate designs, or changes in the use of other fuels caused by changes in gas utility rate designs, may have significant environmental consequences. We would suggest a study of such consequences.

Respectfully submitted,

June 29, 1979

Consolidated Edison Company
of New York, Inc.

By: _____

Joy Tannian
Vice President

792219

DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

Gas Utility Rate Design Study)

Docket No. ERA R-79-22

COMMENTS OF
UNITED DISTRIBUTION COMPANIES

Pursuant to the Notice issued May 3, 1979 by the Economic Regulatory Administration (herein called "ERA") in the above entitled matter, the United Distribution Companies herewith respectfully file these written Comments discussing:

- (1) the importance of every rate design to every distribution utility and all classes of consumers;
- (2) the care and restraint with which the Federal government must approach the injection of new rate designs into tariffs at the local level;
- (3) the consequent scope and course which this mandated study must take in order to be in the consumer and National interests; and
- (4) the necessity for distribution utilities to have full opportunity to present to ERA complete analyses of the implications of each individual rate design which is made the subject of the study.

The United Distribution Companies request the opportunity to participate fully in the proceeding in the hope that their views will be helpful to ERA and in the public and consumer interest.

Filed: July 2, 1979

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I
IDENTIFICATION AND INTEREST OF
UNITED DISTRIBUTION COMPANIES

United Distribution Companies, herein called "UDC" or the "UDC Group", are an ad hoc group of 28 organizations engaged in the local distribution of gas to the general public. The names of the members of the UDC Group are listed on the following page.

In the aggregate, the members of the Group provide approximately 25% of the local gas distribution service rendered throughout the entire United States. Their areas of service comprise cities, towns and metropolitan areas located in the northern and eastern portions of the Nation ranging, from west to east, in the States of Illinois, Wisconsin, Michigan, Indiana, Ohio, Pennsylvania, New York, Kentucky, West Virginia, Maryland and Virginia. The metropolitan areas served include those of Chicago, Milwaukee, Detroit, Indianapolis, Cleveland, Columbus, Pittsburgh, Buffalo, Albany, Rochester, Syracuse and Charleston.

The UDC Group was formed in 1969 as a result of the National shortage of supplies available to their interstate pipeline suppliers, and the consequent depreciation of their own important services to the consuming public. In major part, the efforts of the Group have been devoted to the task of increasing supplies; and, to this end, UDC regularly intervened and actively participated in all area and National rate proceedings before the Federal Power Commission and Federal Energy Regulatory Commission.

The UDC Group is now vitally interested in all Federal actions which result from the Department of Energy Organization Act, the Natural Gas Policy Act of 1978, the Public Utility Regulatory Policies Act of 1978 and other energy legislation enacted in 1978 and which directly affect the operations of local distribution companies. In particular, they have a direct interest in the study of gas utility rate design required by Section 306 of the Public Utility Regulatory Policies Act of 1978.

The name, address and telephone number of the person to whom communications concerning this proceeding may be addressed are:

C. William Cooper, Esquire
159 Town Hall Square
Falmouth, Massachusetts 02540
617-540-0330

IDENTIFICATION OF
UNITED DISTRIBUTION COMPANIES

CENTRAL ILLINOIS PUBLIC SERVICE CO.
CITIZENS GAS & COKE UTILITY
COLUMBIA GAS OF KENTUCKY, INC.
COLUMBIA GAS OF MARYLAND, INC.
COLUMBIA GAS OF NEW YORK, INC.
COLUMBIA GAS OF OHIO, INC.
COLUMBIA GAS OF PENNSYLVANIA, INC.
COLUMBIA GAS OF VIRGINIA, INC.
COLUMBIA GAS OF WEST VIRGINIA, INC.
CONSOLIDATED GAS SUPPLY CORP.
CONSUMERS POWER COMPANY
DAYTON POWER AND LIGHT COMPANY
EAST OHIO GAS COMPANY
EQUITABLE GAS COMPANY
ILLINOIS POWER COMPANY
INDIANA GAS COMPANY
MICHIGAN CONSOLIDATED GAS CO.
MICHIGAN GAS UTILITIES COMPANY
NATIONAL FUEL DISTRIBUTION CORPORATION
NIAGARA MOHAWK POWER CORPORATION
NORTH SHORE GAS COMPANY
ORANGE & ROCKLAND UTILITIES INC.
THE PEOPLES GAS LIGHT AND COKE COMPANY
PEOPLES NATURAL GAS CO.
ROCHESTER GAS AND ELECTRIC CORPORATION
RIVER GAS COMPANY
WEST OHIO GAS COMPANY
WISCONSIN GAS COMPANY

II INTRODUCTION

The Notice in this proceeding requests comment on the "rate designs", "related issues" and "evaluative criteria" to be considered by ERA in the study of "gas utility rate design" mandated by Section 306 of the Public Utility Regulatory Policies Act of 1978 (herein called "PURPA"). It also requests definitions for such designs, issues and criteria. And, finally, the Notice requests "general comments on any other aspects of gas utility rate design which should be addressed in the study."

The UDC Group has no suggestions to make with regard to additional "rate designs", believing those mandated by the statute and named in the Notice to be sufficient.

On the other hand, the UDC Group believes that the "related issues" and "evaluative criteria" which should and must be considered in connection with each rate design are catholic in number as hereinafter set forth.

Most importantly, the UDC Group submits and will show that each "rate design" must be studied in the light of the serious problems involved in injecting new designs into the overall tariffs of distribution utilities or in modifying the existing tariff structure,--for no part thereof may be varied, nor may any new part be inserted therein without considering the effect on the whole and the underlying statutory requirement that the utility tariff, and all interrelated parts thereof shall be just, reasonable, non-discriminatory and non-preferential.

The tariff of a local utility is the heart and soul of the operation, for it is the interrelated group of schedules so designed as to enable the utility to manage and receive its long term supplies and render its utility service to the particular consumers whom it serves in the manner dictated by local needs and weather conditions and by local regulation. Both the utility and all consumers have a direct interest in all aspects of that peculiar local tariff.

Changes in the tariff must be approached by the Federal government with great care and restraint. New designs and new concepts can't be injected by Federal policy without considering the effect on the whole. To do so by indiscriminate Federal fiat would do irreparable harm to long-term local service.

In consequence, this study cannot consider new rate designs in the atmosphere of a few selected "issues" and "criteria". To do so would be wrong from the standpoint of the consumer and public interest. All aspects of the matter must be considered.

And we most respectfully believe that, having heard, ERA will conclude on this important and sensitive matter, that Federal policy should be limited to generic statements of principle which are to be implemented at the local level only to the extent that local necessities of each utility service will permit. As we will hereafter show, this accords with the underlying principle of PURPA.

III THE STATUTORY REQUIREMENT ANALYZED

In view of the points to be made below in our Comments, it will be well to commence by setting forth the exact requirement of the statute.

Section 306(a) of PURPA begins with the general requirement that the Secretary of Energy "shall study and report to Congress on gas utility rate design".

Subsection (a) then provides that: "Such study shall address the effect (both separately and in combination) of the following factors":

"incremental pricing;
marginal cost pricing;
end-user consumption taxes;
wellhead natural gas pricing policies;
demand-commodity rate design;
declining block rates;
interruptible service;
seasonal rate differentials; and
end-user rate schedules"

upon the following listed "items":

- "(A) natural gas pipeline and local distribution company load factors;
- (B) rates to each class of user...;
- (C) the change in total costs resulting from gas utility designs...;
- (D) demand for and consumption of natural gas;
- (E) end-use profiles of natural gas pipelines and local distribution companies; and
- (F) competition with alternative fuels."

Section 306(b) requires that "the Secretary shall develop proposals to improve gas utility rate design and to encourage conservation of natural gas".

And Section 306(c) requires that such "proposals...shall be transmitted, together with any legislative recommendations, to each House of Congress...accompanied by an analysis of:

- (1) the projected savings (if any) in consumption of natural gas and other energy resources;
- (2) changes (if any) in the cost of natural gas to consumers, which are likely to result from the implementation nationally of each of such proposals; and
- (3) the effects of the proposals on other provisions of this Act and on gas utility rate structures."

IV

"OTHER ASPECTS OF GAS UTILITY RATE
DESIGN WHICH MUST BE ADDRESSED IN THE STUDY"

After requesting comment on particular "issues" and "criteria", the Notice requests "general comment on other aspects of gas utility rate design which must be addressed in the study". And, because of our strong concerns for the utility tariff as a whole, our Comments will begin with this general consideration.

Gas supplies for each utility, the consumer needs and demands in each area of service and the resultant tariffs are as different from one another as people are; and what fits one will not fit another. And what will be just, reasonable, non-discriminatory and non-preferential--indeed right and proper--in the tariff of one will be improper in the tariff of another.

The merits and demerits of any particular rate design,--for example, incremental pricing--, cannot be determined on some generic basis applicable to all distribution utilities across the Nation; and so to do would lead the Federal government into actions in contravention of the best interests of gas consumers and the Nation.

There is no single good rate design applicable to the tariffs of all utilities!

We wish to explain the point and its importance in some detail.

Each gas distribution utility is obligated to render services to all consumers throughout its area of service under rates and terms and conditions of service which are just, reasonable, non-discriminatory and non-preferential under and within the meaning of State utility laws and the regulations of local State regulatory bodies. And pursuant to these requirements, each utility has on file and in effect a gas "tariff" embodying one or more "rate schedules", each for a specified class or kind of service, and general terms and conditions applicable to all services.

The tariff is designed in the light of the needs and demands of the whole consumer group throughout the area of service and in a fashion which enables the utility to arrange, receive and handle the long-term supplies needed for that service in the face of the weather pattern imposed by the area of service.

In all instances, this gas tariff has come before the State regulatory authority for review under governing State law, and for determination that each rate schedule and the tariff taken as a whole is just, reasonable, non-discriminatory and non-preferential. In these rate proceedings, the form of the rate schedule, the rate and all other elements which relate to each service are weighed and analyzed in relation to all others.

In earlier days, most gas utilities manufactured their own supplies or secured the same from local gas fields; the heating load was minor in extent because coal dominated the market; and the whole operation was relatively simple. Many utilities had but a single rate schedule applicable to all utility services, residential, commercial and industrial, some embodying a single unit rate for all volumes taken and some being in block form, with the block rates decreasing as the volume of service increased.

But the development of major natural gas pipelines in the 1940's and 1950's and the succeeding growth and dominance of this source of supply materially changed all this.

Natural gas was excessively cheap. Residential, commercial and industrial consumers switched from coal to gas in droves. Demand skyrocketed and load factors fell to 50% or less. At the same time, pipeline capacities were limited and for financial and supply reasons, interstate pipelines offered gas only under rate schedules and service agreements which imposed upon distribution utilities stringent obligations to take and pay for gas.

Balancing low load factor, burgeoning demands against pipeline supplies became an intensely difficult operating matter; and rate schedules which attract and hold industrial service against competition from coal and oil became critical to utility service, on the most economical and sound basis for all consumers. The gas tariff became a group of interrelated classes of service designed to enable the utility to receive supplies and meet the residential, commercial and industrial demands at varying load factors throughout its whole service area.

So operations developed and residential and other loads increased all during the flush natural gas supply years of the 1960's. But then came shortage and curtailment. Faced with deepening pipeline curtailments, local utilities were forced to curtail demand, encourage conservation and develop offsetting self-help supplies, such as SNG, LNG and local production. These major alterations in local operations and service necessarily brought, in their train, tariff changes which were hammered out before local regulatory authorities. The process was difficult and complex and each had to stand the test of local law that it be just, reasonable, non-discriminatory and non-preferential as applied to all consumers in the service area.

The rise of consumerism during the 1970's likewise brought demands for relief for small consumers; and these found their way into gas tariffs via lifeline rates and other means found by the local authorities to be required in the public interests.

And, then in the late 1970's, field prices and pipeline and other supply costs skyrocketed, ending the period in which pipeline rates has been very low and distribution costs represented the major element of a utility's overall cost of service. In those earlier days, the utility had considerable room for flexibility in designing its rates to meet the desires of its several groups of customers, but room for flexibility has disappeared. The pipeline rate to the distribution utility and the high costs of SNG and other self-help supplies now dominate the utility cost of service. Cost of supply, rather than cost of distribution, has become the major element of the overall utility rate. Supply costs must be met on a timely basis out of total service; and the local gas utility has less and less room within which to move from a rate design standpoint.

The rate designs of pipeline supplies, and changes therein, must be carefully weighed in connection with local utility rate design; and changes in local utility rate design may or may not be practicable in the face of particular pipeline rate designs faced by the utility. And, in a growing sense, field sale rate designs impinge directly on local utility problems.

The supply mix and situation of each utility, the overall residential, commercial and industrial demand faced by each utility and the operating problem of melding and balancing these two are different in each case from those of every other utility. And the tariff of each utility is an individually designed group of interrelated rates and provisions, designed to meet the situation and cope with the problems and necessities of an individual service area in accord with local regulation, public policy and consumer demands.

It is with these realities and necessities that each local utility and the local regulatory authority must deal; and injecting particular new designs or modifying existing designs becomes a difficult task.

Federal authority must recognize this fundamental for ill-designed Federal fiat binding on all local utilities could work financial and service havoc at the local level far greater in its damage to consumers and the National interest than are the benefits otherwise stemming from the change.

We most earnestly urge that this study of each separate rate design will carefully consider its place in the overall utility tariff and recognize the ultimate necessity for implementing any Federally desired concept by local authority in accordance with the imperatives of each individual supply-demand situation. Only then can the consumer and National interests be served.

V
"ADDITIONAL RELATED ISSUES"
AND "ADDITIONAL EVALUATIVE CRITERIA"

The Notice in this proceeding quite properly invites comment as to additional "related issues" and "evaluative criteria" which should be considered by ERA in its study.

But the concept--inherent in the Notice--that the study will be confined to, and go forward on the basis of, a limited group of "related issues" and "evaluative criteria" selected by ERA in the light of this inquiry, is plainly wrong.

It is probably impossible to catalogue all of the issues and criteria which bear on the propriety,--and rightness in the consumer interest--, of inserting a new rate design into the tariffs of all distribution utilities across the Nation and even into the tariffs of all UDC Members. And the development of issues and criteria should come about only as ERA gains knowledge of local utility problems as this matter progresses and, hopefully, in the light of facts developed in a series of consultations with, and comments of, distribution utilities, such as those before the Federal Energy Regulatory Commission in connection with incremental pricing.

As we have pointed out above, the tariffs of distribution utilities are individually designed to accommodate the supply-demand situation of each particular utility; and the following in varying degree are only some of the many issues and criteria which govern the terms and content of the tariff of a utility and of each of the several rate schedules or rate designs therein:

- (1) The existence and terms of the take or pay provisions of the rate schedules of its pipeline supplier and the relation between demand and commodity charges in pipeline rates. And a utility may have three or even five pipeline suppliers whose terms of service must be accommodated in its own local rates.
- (2) The relation of the cost of pipeline supply to overall cost of service of the utility; and, as pipeline costs increase, the utility has less and less mobility in rate design. The cost of pipeline supply is as much as 70% or 80% of total utility cost of service and is steadily increasing.
- (3) The utility's situation with regard to local production, SNG, LNG, storage and other means of self-help; and the costs of these important supplies in relation to overall costs of service.
- (4) The size and character of the industrial demands served by the utility; and the relation of these demands to residential and commercial demands and storage.

- (5) The weather in the area of service, the size of the heating demand and the load factor faced by the utility.
- (6) The volatility of utility revenues due to the character of the industrial loads and of the weather in the area of service.
- (7) The relationship of the utility's storage facilities to overall demand.
- (8) The trends of residential, commercial and industrial demands in the area.
- (9) The trends in revenue and overall costs of service; and their stability from year to year.
- (10) The cost of rendering each kind of service, as determined by allocations of the utility's total cost of service among the several customer classes and kinds of service.
- (11) The effectiveness of each of the utility's rate designs in yielding expected shares of the overall cost of service.
- (12) The effectiveness of each rate design in discouraging wasteful use, while promoting justified use.
- (13) The necessity that the overall tariff and all parts thereof must be just, reasonable, non-discriminatory and non-preferential as among all consumers.

All these and others are "issues" and "criteria" which bear--in varying force and effect from utility to utility--on the rightness and necessity of new rate designs.

In the consumer and public interest, therefore, ERA cannot afford to limit the study to a few specified issues and criteria determined upon in the initial stages of this study.

It is, respectfully, submitted that ERA should proceed in this important matter much as the Federal Energy Regulatory Commission has been proceeding in connection with incremental pricing under the Natural Gas Policy Act. In that matter a series of tentative proposals have been issued by the Commission and each has been made the subject of public conference, in which all members of the industry and State Commissions were able to present views and enter into discussion with the Commission's Staff. Only in this way and through these continuing exchanges of views can the essential issues and criteria be made plain.

VI "DEFINITIONS"

Definitions, as requested by ERA, are of extreme importance; but these, too, cannot be categorically determined for all time at this early stage of the study. Distribution utilities must know the scope and thrust of the study through tentative early proposals issued by ERA before definitions can be attempted; and these definitions will change and grow as the study progresses from stage to stage.

Take for example the term "incremental pricing". This has one particular meaning in the context of the surcharges mandated by the Natural Gas Policy Act; but it can have a quite different definition if it were to be utilized by a local distribution utility in a general rate form.

VII PURPA'S PROVISIONS FOR LOCAL CONTROL OF ELECTRIC RATES MUST APPLY IN THE CASE OF GAS

Title I of PURPA establishes several standards for electric utility rate design; but it is important to note that these standards are not automatically binding upon local utility tariffs and regulation. Local state authorities are required to consider the same in appropriate proceedings, but they have the opportunity, in every instance, to determine whether the standard is "appropriate" to implement and consistent with "otherwise applicable state law". And if they determine that it is not "appropriate" to implement the same or that the same is not consistent with "applicable state law", they may so find and the standard does not apply.

The foregoing supremacy of local rules and authority is emphasized in Section 111(a) and (c)(2) and in Section 113(a) of the Act. Federal design standards are in all cases subjected to the test of local regulatory needs and requirements.

It is submitted for the reasons given above that this same principle must guide and govern the study and proposals of ERA with respect to "gas utility rate design".

Rate design can no more be determined by Federal rule and fiat in the local gas utility operation than in electric. Federal rate design standards emanating from this study should be implemented at the local level only insofar as they are determined by the local State Commission to be "appropriate" and "consistent" with otherwise applicable state law" as provided for electric service by Sections 111 and 113 of PURPA.

Indeed, the necessity for local control is even more important for gas than for electricity. Electricity is used for a myriad of purposes, many of which are optional with the user. But gas for residential usage comes down to three basic necessities: cooking, water heating and space heating; and the entire utility operation and tariff are geared to insuring that these supremely important domestic needs will be met at all times. Every tariff change must be viewed in its relation to this basic service and this can only be done at the local level.

VIII RECOMMENDATION

In the light of the foregoing, United Distribution Companies, respectfully, recommend that ERA not confine its study of any rate design to particular "issues", "criteria" and "definitions", as stated in the Act and otherwise determined and specified by ERA at this time.

The matter is so important that ERA should move forward via tentative proposals and procedures which provide opportunity for full and frequent conferences and comments, so that a full light may be shed on all aspects of "gas utility rate design" and the nature and fundamentals of local distribution operations and problems. The distribution utilities and local regulatory bodies have been wrestling with these matters for a long time and they should participate throughout.

It is also recommended that the study and resultant proposals to Congress contemplate that Federal action will be limited to general policy pronouncements which are to be implemented by local State regulatory agencies only to the extent that they are determined to be "appropriate" and "consistent with otherwise applicable state law", as provided in Sections 111 and 113 of PURPA.

The United Distribution Companies request, in the consumer interest, full opportunity to participate in the study as it progresses and to respond to the proposals of ERA prior to their submission to Congress.

Respectfully submitted,

UNITED DISTRIBUTION COMPANIES

by
C. William Cooper, Esquire
159 Town Hall Square
Falmouth, MA 02540
617-540-0330

AFFIDAVIT

Commonwealth of Massachusetts)
County of Barnstable) ss.

C. William Cooper, being duly sworn according to law, says that he is counsel to the United Distribution Companies, that he has read the foregoing Comments of United Distribution Companies and is familiar with the contents thereof, that he has executed the same for and on behalf of United Distribution Companies with full power and authority so to do, and that the facts therein set forth are true and correct to the best of his knowledge, information and belief.

C. William Cooper, Esquire

Subscribed and sworn to before me this 29th day of June, 1979.

Notary Public

My Commission expires:

KARL S. TENNEY
NOTARY PUBLIC
COMMISSION EXPIRES MARCH 15, 1984

COMMENTS OF LONE STAR GAS COMPANY
TO THE DEPARTMENT OF ENERGY FOR
GAS UTILITY RATE DESIGN STUDY

Lone Star Gas Company, a Division of ENSERCH CORPORATION, owns and operates a major transmission system and over 400 gas distribution systems in the States of Texas and Oklahoma. Due to the peculiar nature of gas utility rate regulation in Texas, Lone Star currently operates under a separate rate schedule for each of the over 400 distribution systems served. Realizing that other companies throughout the country also distribute and transport gas under various combinations of rate designs, Lone Star would suggest that in the conducting of the Rate Design Study the Economic Regulatory Administration make themselves aware of the actual experiences of both utility companies and consumers operating under various rate designs. Gas utilities have implemented many differently revised and new rate structures during recent years. In some instances, the new rate structures have been conceived or imposed by regulatory bodies and in other cases, the utility has acted on its own initiative and the regulatory body has approved these rate structures. Any rate structure change has impact. It is also practical to realize that any beneficial impact that is gained when rate structures are changed is offset by some degree by a detrimental impact, i.e., one result causes a second result. Sometimes, the different results are contemplated and studied in advance of changed rate structures being implemented, but sometimes all the different results are not so contemplated and/or studied in advance. Actual results provide more useful information than estimated results. For these reasons, Lone Star would suggest that any new Rate

Design Study undertaken by the Economic Regulatory Administration be concentrated upon actual results of changed gas utility rate structures; not upon estimated results which are to be based upon assumptions and theories. Actual experience will be far more helpful in developing any recommendations and report to Congress than will theoretical studies.

Very practically, costing cannot be considered the same as pricing. Any rate design study should consider the causes of costs and the causes of cost changes. Costs (actual costs) must be or should be reflected in prices. Prices for gas utility service can and do cause some gas utility costs to change, but to a much more significant degree (sometimes to a drastic degree), cost changes cause price changes. No rate design study should be initiated before the causes of actual costs are determined. Cost assignment and allocation methodologies must be real and practical; not unreal and impractical.

Respectfully submitted,

Hester L. Anders

Attorney for Lone Star Gas Company,
a Division of ENSERCH CORPORATION
301 South Harwood Street
Dallas, Texas 75021
Phone: 214/741-3711

National Oil Jobbers Council
1707 H Street, N.W., 11th Floor
Washington, D. C. 20006 202/331-1198

792211

E-79-302

June 30, 1979

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street N.W.
Docket ERA-R-79-22
Washington, D.C. 20461

Dear Sir or Madam:

The National Oil Jobbers Council (NOJC) appreciates the opportunity to comment on the gas utility rate design study required under the Public Utility Regulatory Policies Act of 1978.

NOJC is a federation of 44 state and regional trade associations representing thousands of independent small business petroleum marketers. Members wholesale or retail many petroleum products including heating oil, motor fuel, kerosine, LP gas, and residual fuel oil. Together our members market almost 80% of the heating oil sold in the United States.

NOJC comments on the following aspects of the gas design study.

Additional rate designs and related issues.

Any comprehensive study of gas utility rate design must examine the concept of "return on rate base" which is the fundamental basis of all utility rates in the country. Where the rate base is measured by the assets that the utility owns or builds - as is almost invariably the case - the utility is encouraged to build unnecessary or marginally necessary plant and equipment. This results in unnecessary costs being passed on to the gas consumer, and defeats all three of the mandates of Title III of the Public Utility Regulatory Policies Act, especially the goal of "optimization of the efficiency of use of facilities and resources by gas utility systems."

Among the options DOE may wish to examine could include:

- o return on equity.
- o a fixed margin per unit of gas sold.
- o a fixed annual dollar return, based, for example, on the "cost plus" principle of government contracting.

Although study of this issue is not specifically required by PURPA, the Act does not preclude DOE from taking the initiative in examining other rate design issues, and, in fact, DOE already has undertaken studies of other rate designs not included by Congress. Because of the importance of the rate of return issue on the goals of PURPA, NOJC encourages DOE to include the issue in its gas rate study.

Opportunities for Consultation and Comment.

One of the evaluative criteria with respect to which rate designs and related issues must be analyzed is "competition with other fuels." The retail fuel oil industry, which NOJC represents, is affected severely by changes in rates and rate designs of gas utilities. Accordingly, NOJC applauds DOE's efforts to provide substantial opportunities for public comment throughout the study period, and in addition encourages DOE to include representatives of fuel oil dealers along with the representatives of state regulatory commissions, gas utilities, and gas consumers as mandated by PURPA.

Respectfully submitted,

James Hickel
Economist

**Consumers
Power
Company**

W. J. Jefferson
*Executive Director of
Rates and Regulation*

General Offices: 212 West Michigan Avenue, Jackson, Michigan 49201 • Area Code 617 788-1230

June 29, 1979

Department of Energy
Office of Public Hearing Management
Room 2513, 2000 M Street, NW
Washington, D.C. 20461

RE: Docket ERA-R-79-22

Gentlemen:

The following comments are Consumers Power Company's initial response to the Department of Energy's proposals regarding a gas utility rate design study pursuant to Title III, Section 306 of The Public Utility Regulatory Policies Act of 1978 (PURPA) as outlined in the Federal Register, Volume 44, Number 67, Page 26055 (April 30, 1979).

Consumers Power Company (The Company) is a combination gas and electric utility serving over 1,000,000 gas customers and 1,250,000 electric customers in the lower peninsula of Michigan. The Company has actively performed gas cost of service analyses, gas load analyses, and gas rate design by class of service over the last 15 years.

The Company strongly believes that each state utility commission should continue to determine what is the appropriate rate design for service in the service area of gas distribution companies subject to its jurisdiction. A particular gas rate design may not be universally appropriate to each state or even to each utility within a state. Gas distribution companies serve unique territories composed of widely varying mixtures of residential, commercial and industrial customers using gas in diverse manners and subjected to differing weather, gas supply, and economic conditions. At the least, there is a significant difference in degree days and a related saturation of space heating load experienced by gas utilities regionally. Such dissimilarities dictate unique production, storage, transmission, and distribution facilities to insure reliable service, and cause a substantial variance in costs.

Section 306 of PURPA identifies six rate designs and the Economic Regulatory Administration (ERA) would add three other rate designs to be included in the study. It is particularly troublesome that average cost or accounting cost pricing is absent from such a list. Such a cost basis may be inherent in some of the rate designs specified. However, since incremental pricing and marginal cost pricing are identified as the number 1 and 2 items to be studied, certainly it is reasonable to add the traditional average cost method of rate design explicitly to the list of methods for evaluation. Cost of service and the associated rate design based on an accounting cost basis has been the cornerstone of the gas utility business. It is the basis to which any other approach should be compared. The accounting cost basis is an understandable process; it minimizes the need for the gross estimations and assumptions required of marginal cost or incremental cost studies; it ties directly to the revenue requirement constraints faced by each regulated gas utility; and most important, it has worked and continues to work.

The rate designs identified for study need further clarification. Confusion is created by the inappropriate mixing of bases of rate design (incremental costs, marginal costs, and, if added, accounting costs) with types of rate design (seasonal rates, demand - commodity rates, declining block rates, end-user rates, volumetric rates, lifeline rates, and inverted rates). The Company therefore recommends that all future pronouncements and inquiries concerning such a gas utility rate design study differentiate between the basis of any rate design and the type of rate design resulting from the basis.

The end-user type of rate schedule follows from some arbitrary assignment of "priorities" or from some determination of the "value" of the gas service to the end-user. It follows then, that the study should include an investigation into the appropriateness of arbitrary determinations of priorities for gas service and value of service determinations as bases of rate design. The lifeline type of rate develops from considerations of social or moral objectives as bases of rate design. Certainly, such social or moral objectives should also be added to the list of bases for evaluation.

One additional aspect of the type of rate design should be added to the scope of the study - the customer component of any rate. Perhaps this has been unintentionally included within Item number 4 - demand - commodity rate design. Certainly the "CED rate" type, i.e. customer - energy (commodity) - demand is an appropriate form of rate to be evaluated by any meaningful study.

Six criteria by which the various rate designs are to be evaluated are listed in the inquiry. Absent from the list is cost of service. The Company believes that cost of service by class of service or rate schedule should be the primary basis for evaluating rate design. A customer's charge for gas service should be based upon the supplying utility's costs that the customer has caused the utility to incur. Such a basis is essential in establishing an appropriate, rational schedule of rates. It is not clear that an appropriate cost basis is contemplated by any of the six criteria.

"Evaluative criteria" number 3 needs further clarification. In its present form this criterion is meaningless and without value.

With the exception of incremental pricing and marginal cost pricing, the other rate design items and the evaluative criteria, with the exception of Item 3, as discussed above, have generally accepted meaning throughout the industry. Certainly, the terms used in this inquiry should follow that common understanding. The definitions of "incremental [cost] pricing" (pricing based upon the added cost of the next increment of capacity) and "marginal cost pricing" (pricing based upon the cost of the next additional unit of output) depends upon the time horizon to be selected. The selection of a short-run or a long-run horizon dictates which functional costs must be analyzed. There is no universally accepted approach. We would hope that the inquiry would thoroughly cover the alternate approaches to these costing methodologies.

Consumers Power Company appreciates the opportunity to offer our comments on this important issue and would be pleased to provide further details if requested. We look forward to participating in this important inquiry.

Correspondence concerning this submission should be addressed to:

Mr William J Jefferson
Executive Director of
Rates and Regulation
Consumers Power Company
212 W Michigan Avenue
Jackson, Michigan 49201
Telephone: (517) 788-1230

Very truly yours,

A handwritten signature in dark ink, appearing to read "W. J. Jefferson", followed by a long horizontal flourish.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

795213

before the
Economic Regulatory Administration

Gas Utility Rate Design Study)

Docket No. ERA-R-79-22

COMMENTS OF
ASSOCIATED GAS DISTRIBUTORS

In response to the April 30, 1979, Notice of Inquiry in this proceeding, Associated Gas Distributors (AGD)^{*/} submits the following initial comments on the several issues presented here for comment:

I. Interest of AGD

AGD is an informal grouping of some 44 east coast natural gas distribution companies. Together, these companies serve about 11 million gas consumers and account for about 25 percent of the gas sold annually in the interstate gas system. Each of the AGD companies is subject to rate regulation at the state or local level pursuant to the laws of their respective states. As a result of wide variations between the characteristics of their service areas and markets, the AGD companies operate under substantially different rate designs.

The rate design study authorized by the Public Utility Regulatory Policies Act of 1978 (PURPA) may form the foundation for recommendations regarding federal rate design standards applicable to local gas utilities. To the extent this occurs, AGD companies will be directly affected by the outcome of this study. AGD's interest, therefore, is to assure that any conclusion

^{*/} A list of the AGD member companies is attached hereto as Appendix A.

reached in this study is fully and thoughtfully considered in the light of all relevant criteria and that full and fair consideration is given to the impact of any rate design judgments on the local gas distribution companies and their customers.

II. Specific Rate Designs to be Considered in the Study

First among the features of the rate design study on which comments are sought is the list of specific rate designs which should be evaluated. ERA has identified three rate design techniques for evaluation in addition to the rate designs specified by Section 306 of PURPA. These additional techniques are volumetric rates, lifeline rates and inverted rates. In the interest of providing a more comprehensive and well-rounded study of rate designs currently or potentially in use by gas utilities, this list of rate designs should be supplemented by including the following rates design techniques. In suggesting these additional rate design approaches for the study, AGD takes no position on the merits of the designs. AGD's recommendations are made in the interest of providing a complete and comprehensive review of present and foreseeable rate design techniques.

(a) Rate Based on Fully Allocated Costs

Absent some special rate design objective, retail gas rates are frequently based on the principle that each rate is designed to yield revenues which match the full cost of rendering the class of service to which it applies. This conventional rate design structure should be considered along with other

rate designs if the study is to provide a basis for comparing the merits of the full range of currently-used rate design approaches.

(b) Variable Volume Adjustment Clauses

This clause refers to a feature which adjusts the level of a given retail rate level according to the volume of sales being rendered; larger sales tend to lower the unit rate and reduced sales tend to increase unit rates, with the objective of maintaining a level rate of return for the gas utility.

(c) Standby Rates

This rate design is one in which a fixed charge is imposed on a gas user equipped to use an alternate fuel, as well as natural gas, for certain purposes. It is designed to yield revenues commensurate with the cost incurred in maintaining the ability to provide "backup" on standby service on demand whenever the customer elects not to use its alternate fuel.

(d) Incentive Rates

In the interest of promoting or encouraging the development of one or more specific new energy sources or forms, gas utility "incentive rates" may be designed to provide higher rates of return on investments in (1) renewable gas supply sources such as biomass or garbage, (2) gas exploration and development activities by gas utilities, (3) solar energy

applications in combination with gas usage or

(4) other new sources such as gas from coal,

Devonian shale, geopressured brine, etc.

III. Evaluation Criteria

In addition to the statutory criteria, ERA has proposed that the study be expanded to use the factor of "equitable rates to consumers" as one of the standards against which to test rate design techniques. In response to that proposal, it should be observed that the term "equitable rates" is not defined in the April 30 Notice of Inquiry, nor does it appear to have any generally understood definition. On the contrary, this term is a highly subjective, value-laden factor which may prove to be difficult to apply in any useful way. Whether a given rate design is equitable would seem to depend upon which of the many other objectives of rate design are regarded as primary in value to the gas consumer. Equitable rates may be those which recover allocated costs or marginal costs, those which yield increasing sales, those which tend to increase long term supply, etc. In the absence of some objective definition of "equitable rates for gas consumers," the use of that term as a standard for evaluating rate designs is of doubtful value. Rather, this term should be considered as adequately reflected in the other, more objective evaluative factors outlined in the statute and proposed below as supplemental criteria for assessing gas utility rate designs.

Apart from the mandatory rate design criteria, there are several other factors which should be added to insure a thorough evaluation of whatever rate designs are studied. These include the following: (a) the compatibility of a given rate design technique with the requirements of state rate regulation (b) the impact of a rate design on imports of petroleum (c) the environmental impact of a given rate design's implementation (d) the Btu efficiency of energy usage resulting from a given rate design and (e) the regulatory expenses relating to the adoption and administration at the state level of a given federally-mandated rate design technique. Each of these factors is distinguishable in substance from the criteria set forth in Section 306 of PURPA as relevant factors for evaluating a given rate design approach. Similarly, each of these factors represents a relevant public interest or concern which deserves attention in any complete assessment of a gas utility rate design technique.

IV. Definitions of Rates and Evaluative Costs

In requesting comments on definitions of terms used in the study, ERA has not supplied any proposed definitions of the rate design features or evaluative criteria which will be used in the study. As a first recommendation, therefore, we suggest that tentative definitions of key terms be published as soon as possible so that useful responsive comments can be submitted.

Additional preliminary recommendations regarding definitions include the following points: (a) in using the term "costs" in relation to gas utility service, ERA should take into account and quantify the cost associated with idle or under-

utilized capacity of local gas distribution systems; and, (b) in assessing the competitive position of gas in relation to alternative fuels (see Section 306 (a)(2)(f), PURPA), ERA should take into account the direct and indirect subsidies accorded to competitive fuels.

V. Opportunity for Public Consultation and Comment

To discharge its statutory duty to consult with representatives of state regulatory commissions, gas utilities and gas consumers, two types of consultation processes are recommended.

First, ERA should issue periodic Federal Register notices providing all of these groups with information concerning the progress of its study, the steps taken to implement the Section 306 mandate, the topics on which public input is requested, etc. This series of formal notices would enable any interested party to become informed of ERA's efforts and to provide comments and suggestions "on the record."

Second, ERA should provide an opportunity for working-level interaction between its staff and personnel representing state agencies, gas utilities and gas consumers. The considerable expertise in rate design matters that resides in the latter three groups could prove invaluable to ERA in developing a study of the scope and depth which the statute contemplates and which will be essential if sound conclusions are to be its ultimate product. To provide a medium in which this expertise can be communicated may require a working committee of experts from ERA and these

groups meeting on a regular basis as often as circumstances require. As a representative of the gas utility industry, AGD is prepared to cooperate in the formation and implementation of such a working committee.

IV. General Comments and Conclusion

The overall purposes of PURPA Title III are to encourage (a) gas conservation, (b) optimum use of gas utility facilities and (c) equitable rates to gas consumers. AGD fully supports these goals as consistent with the long run interests of its member companies, their stockholders and their customers. At the same time, ERA should proceed with great caution and objectivity and with a maximum use of available data in conducting the gas utility rate design study. This study, by its nature, places the Federal government in the role of judging the efficacy of government at the state level and, as such, is fraught with potential problems. The exclusive jurisdiction of state commissions to regulate gas utility rates has prevailed for over a century. The gas utility industry has become a cornerstone of the nation's energy distribution system during that time. Having survived a period of severe and chronic shortage during the past seven to eight years, the gas distributors dependent on the interstate gas pipeline system are now looking ahead to a period of renewed growth and vitality after the passage of the National Energy Act. While recognizing the value of the three statutory goals mentioned above, AGD submits that ERA should not assume that the present system of

exclusive state regulation of the gas utility industry is somehow deficient simply because state-administered rate design techniques are under review. Properly structured and administered, the instant study will condemn that assumption and produce a result of value to all concerned.

Respectfully submitted,

ASSOCIATED GAS DISTRIBUTORS

By

Frederick Moring

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July 2, 1979

ASSOCIATED GAS DISTRIBUTORS

Baltimore Gas & Electric Company
Bay State Gas Company
The Berkshire Gas Company
Boston Gas Company
Bristol & Warren Gas Company
The Brooklyn Union Gas Company
Cape Cod Gas Company
Central Hudson Gas & Electric Corporation
Chesapeake Utilities Corporation
City of Holyoke, Mass., Gas & Electric Dept.
City of Westfield Gas & Electric Light Dept.
Commonwealth Gas Company
Concord Natural Gas Corporation
The Connecticut Gas Company
Consolidated Edison Company of New York, Inc.
Delmarva Power & Light Company
Elizabethtown Gas Company
Fall River Gas Company
Fitchburg Gas & Electric Light Company
Gas Service, Inc.
Haverhill Gas Company
Long Island Lighting Company
Lowell Gas Company
Lynchburg Gas Company
Manchester Gas Company
New Bedford Gas & Edison Light Company
New Jersey Natural Gas Company
New York State Electric & Gas Corporation
Northern Utilities, Inc.
The Pequot Gas Company
Philadelphia Electric Company
Philadelphia Gas Works
Providence Gas Company
Public Service Company of North Carolina, Inc.
Public Service Electric & Gas Company
South County Gas Company
South Jersey Gas Company
The Southern Connecticut Gas Company
Tiverton Gas Company
UGI Corporation
Valley Gas Company
Washington Gas Light Company

792211-A

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

before the
Economic Regulatory Administration

Gas Utility Rate Design Study) Docket No. EPA-R-79-22

COMMENTS OF
NEW JERSEY NATURAL GAS COMPANY

The Economic Regulatory Administration in the Docket listed above, by notice dated April 30, 1979, provided the opportunity for consultation and public comment regarding the Gas Utility Rate Design Study as mandated by Title III, Section 306 of the Public Utilities Regulatory Policy Act of 1978. New Jersey Natural Gas appreciates this opportunity for comment and is anxious to consult further with ERA throughout the conceptual, developmental and analytical phases of the study.

New Jersey Natural is a natural gas distribution company serving approximately 220,000 customers in Morris, Monmouth, Ocean and Cape May Counties. Because our customers, 85 percent of whom are residential consumers, are provided the lowest retail rates in the State and probably on the East Coast, any Federal study which examines and potentially impacts local ratemaking procedures and practices is of great interest. As the study may form the basis for recommendations to Congress, state regulatory agencies and local distribution companies relating to the aforementioned procedures, New Jersey Natural and our customers will be directly affected by the progress and results of this study. New Jersey Natural is primarily concerned that the Federal examination not preempt state level standards or policies; that several definitional problems be resolved; that an interface with energy legislators be established and maintained; that consultation and comment from interested parties is continually solicited; and that the study not become a self-fulfilling prophecy but weigh all objectives fairly against each rate design considered.

Preemption of State Standards or Policies

Section 306(c)(2) speaks of changes brought about by "nationalization" of rate design standards. While some elements of the Natural Gas Policy Act and the related pricing mechanisms, e.g., incremental pricing, have arguably laid the

groundwork for national ratemaking, New Jersey Natural strongly supports the view expressed by the Associated Gas Distributors (AGD) in that the assumption must not be made that the local rate designs are necessarily improper or that their implementation results in rates which impose undue burdens on the consumer. Also, New Jersey Natural believes that the study can be of great value if as proposed in 306(c)(3), it examines not only the effects of various rate designs on other provisions of the Act, but also examines the impacts of various sections of the Act on consumers as implemented through various rate designs and thereby impacting equitable rates to consumers.

Definitional Problems

Throughout the April 30 notice, several issues are mentioned which obviously require further definition. In particular, New Jersey Natural believes that while improvement of gas utility rate design, optimization of efficiency and equitable rates are each erstwhile goals, they are highly subjective concepts, susceptible to varied interpretation and errant assumptions. They must be defined carefully in light of the evaluative criteria and applied uniformly for each iteration of this study.

Legislative Interface

Although Section 306(a)(1) specifies a maximum period of 18 months to report to Congress, interim status or progress reports would be appropriate. Just as continued public comment is contemplated, periodic reports of problem areas and findings to the Commission and Congress would lead to earlier identification of problem areas and prepare for future proceedings regarding any rate structure which the study may find to be discriminatory or contrary to the stated goals of the Act, particularly with respect to marginal cost or incremental pricing techniques.

Public Comment

Section 306(d) requires the study to be conducted with public participation. Although the model(s) to be used may currently be developed, New Jersey Natural encourages ERA to continue its stated interest in public comment. Moreover, Section 306(a)(1) states that regulatory commissions, gas utilities and gas consumers should be given the opportunity for consultation. This process should not function as a "one-way street," only in response to findings. Rather, it should operate pro-actively by perhaps monthly requests or notices seeking assistance and input to direct the progress of the analysis. In this way ERA would recognize the value of the

varied expertise which exists within the sectors from all parts of the country and maximize its usefulness to this undertaking.

Self-fulfilling Prophecy

As mentioned earlier, any initial assumptions which prejudice the merits of particular rate design or criteria for evaluation would serve to taint the effectiveness and validity of the study and result in biased, preordained findings or recommendations. As outlined in the Act, the scope of the study includes market sensitivities, seasonal variations, elasticities of price and demand and consumption patterns as well as market characteristics, supply mix and ratemaking strategy. Because these factors are so complex and judgment laden, New Jersey Natural believes that only by maintaining the ultimate degree of analytical objectivity can the study be considered useful or its findings considered practicable.

Clarity of Criteria

As evidenced by the hiatus caused by the implementation of incremental pricing, unclear criteria and disparate applications are counterproductive and misleading. Every effort should be made to avoid this in the rate design study. By targeting on equitable rates to the consumer brought about by national rate design standards, New Jersey Natural feels that while socialization and nationalization are venerable goals, the role of the local distribution company in monitoring trends within its service territory and the role of the state regulatory agency and the nexus between the two must not be disrupted or altered by a push toward federally-mandated standards.

It is, thus, imperative that criteria be clearly defined and uniformly applied.

Conclusion

New Jersey Natural recognizes the merits and the pitfalls which the study poses. We are encouraged by the tone of the statute, which urges public participation, and by ERA's stated receptivity to this process.

Awareness of the potential dangers and periodic fine-tuning of the evaluative mechanisms will ensure the proper conduct of the study resulting in meaningful, well-formulated conclusions, proposals or recommendations, which will be of use to all concerned. Particularly during this period of

revitalized growth and attitude brought about by the National Energy legislation, New Jersey Natural believes that such a study, if well managed and administered, if extremely well-timed, may serve to answer certain vital questions, will make maximum use of existing data and will assist each participant in similar studies which have become so popular and imperative on the local level.

Respectfully submitted,

NEW JERSEY NATURAL GAS COMPANY

By

John S. Sadowski
Manager, Gas Supply

792215

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July 2, 1979

Department of Energy
Office of Public Hearing
Management
Room 2313
2000 M Street, N.W.
Washington, D. C. 20461

Re: ERA-R-79-22: Gas Utility Rate Design Study, Responsibilities
Under Public Utility Regulatory Policies Act of 1978

Gentlemen:

In response to the Notice of Inquiry published in the Federal Register Thursday, May 3, 1979, at page 26055, the Interstate Natural Gas Association of America (INGAA) herewith submits its views and comments regarding the above study. The person to contact in regard to these comments is Arthur G. Gillum, Director of Finance and Accounting, Interstate Natural Gas Association, Suite 601, 1660 L Street, N.W., Washington, D. C. 20036, telephone (202) 293-5770.

INGAA is a nonprofit trade association representing virtually all of the major natural gas transmission companies operating in interstate commerce in the United States. The interstate natural gas transmission industry has been subject to extensive regulations for a number of years and under current law INGAA's member companies are subject to rules and regulations of the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) as well as other departments and agencies of the Federal Government. INGAA has a vital interest in the study authorized by the Public Utility Regulatory Policies Act (PURPA).

Pursuant to Section 306 of PURPA, the ERA study is to serve as the basis for legislative proposals "to improve gas utility rate design and encourage conservation of natural gas." These legislative proposals to be submitted to Congress by the Secretary of DOE could impact interstate natural gas transmission companies as well as the operations of their customers. Therefore, it is INGAA's recommendation that the interstate gas transmission industry be permitted to actively participate in all stages of the development of the study, and that the industry be afforded the opportunity to review and comment on utility rate design proposals prior to submission to Congress.

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ERA Study Must Reflect Current Energy Policy

PURPA was enacted into law within an energy environment which urged conservation of natural gas to husband a depleting resource. Certain significant alterations in this environment have since occurred, including double digit inflation, higher cost and lower quantity of both domestic and imported oil supplies, and the recent nuclear generation setbacks, all of which have contributed to a shift from a strict conservation policy. The Federal Energy Regulatory Commission's (FERC) revisions in the pricing of gas production, as well as the recent incremental pricing concepts soon to be implemented, have also contributed to an energy environment that differs considerably from that which existed less than two years ago.

In recognition of these changing conditions, it is mandatory that the anticipated energy environment be defined prior to the formulation of legislative proposals to assure the continued appropriateness of the objectives of the study. An energy policy which encourages a strategy directed toward preservation of natural gas can result in gas utility rate design proposals substantially at variance with a strategy directed toward compensating for oil and nuclear shortfall. The extant energy environment not only will dictate the thrust of gas utility rate design proposals, but also will require the study to be conducted within a well defined order of priority as to the stipulated objectives of Title III---conservation, optimal use of facilities and equitable rates. The uncertainty of the current energy environment serves to emphasize that the ERA study must incorporate data and criteria of a nature that will permit the formulation of legislative proposals consistent with the national energy policy.

Computer Model Considerations

Since a computer model is to be an integral part of the system study, the basic assumptions, criteria, and data input used in its construction will have a direct relationship on the validity of the output and the ultimate practical value of the legislative proposals developed from such study. The sensitivity and complexity of this analytical tool would appear to dictate the exploitation of all the ratemaking expertise available to assure its authenticity. For this reason, it is suggested that industry working committees be utilized to the fullest extent to assure both the theoretical validity and practical applicability of the model.

The model should have the ability to measure the impact created by the interaction of cost and volume changes between a pipeline and its distribution customers. End-user curves should be utilized which reflect existing market requirements. To effectively analyze retail rate design implications, the model must also be capable of adapting to pricing definitions made by the FERC in its interpretation of the NGPA which may materially differ from traditional definitions (e.g. incremental pricing).

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Further, it is suggested that the model's structure and data input, both prior and subsequent to its construction, be available for public comment.

Public Participation

In addition to public participation in the modeling process, it is strongly urged that the public be encouraged to participate in all other critical stages of the study/legislative proposal process, either through written comment, public hearings or working committee vehicles. The suggested stages for such participation are:

- (1) Prior to and during the modeling process,
- (2) At the completion of the rate design study,
- (3) Prior to the drafting of legislative proposals,
- (4) Prior to the submission of the legislative proposals to Congress.

Pipeline Rate Design Implications

Although Title III is directed primarily toward retail pricing policies for natural gas utilities, any revisions directed to the determination of the price to be paid and volumes consumed by the end user will influence the interrelationship between interstate pipeline and distribution company rate designs. It must be remembered that there is an important individuality in pipeline-distributor company relationships that is difficult to incorporate into a generalized computer model. Therefore, we believe care should be taken in drawing conclusions without giving some flexibility to reflect this individuality. While the natural gas industry is essentially divided into three sectors--production, interstate transmission/sale and intrastate distribution--each with its own operational characteristics, rate design problems, and regulatory control--it is nevertheless essential that gas utility rate design proposals be promulgated and coordinated within this integrated framework.

Regulatory Considerations

Recognition must be given to the effect that the FERC decisions on an interstate pipeline's rate structures have on its customer distribution companies rate composition. For instance, an ongoing controversy has existed regarding the apportionment of fixed costs between the demand-commodity components of a pipeline's rates. The "United" method allocates 75% of the fixed costs to the commodity component. In contrast, the "Seaboard" method allocates 50% of the fixed costs to commodity components. The differences between these methods have a significant impact on the shifting of costs between low and high load factor distribution customers. Both federal and state regulatory policies must be addressed prior to formulation of rate design proposals under Title III.

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The responsibility and authority for gas utility rate design is currently vested within the FERC and the various state Public Utility Commissions. To assure the authenticity and credibility of its output, the ERA study must be coordinated with the FERC as well as the state regulatory bodies to obtain the benefits of the expertise and practical experience of these agencies. A close coordination between the regulatory agencies can only be achieved if they are consulted during the developmental stages of the study and are allowed to participate in the formulation of legislative proposals.

We recommend that the Federal Government exercise great care and constraint in injecting rate design concepts into tariffs at the state level.

Conclusion

INGAA wishes to emphasize that the ERA study and any legislative proposals based on such study must take into consideration the unique marketing requirements of the various geographical areas serviced by the interstate pipeline industry as well as the close interrelationship between each pipeline's rate structure and the rate structures of its customers. Without the proper consideration of all the factors raised, the ERA study and resultant legislative proposals will be invalid. For this reason, as well as those expressed in the above comments, INGAA urges that the ERA study be conducted in close cooperation with representatives of the interstate pipeline industry.

Sincerely,

Arthur G. Gillum
Director, Finance & Accounting

AGG/jed

MANUFACTURING CHEMISTS ASSOCIATION

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July 2, 1979

792216

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street, N.W.
Docket No. ERA-R-79-22
Washington, D.C. 20461

Gentlemen:

The Chemical Manufacturers Association (CMA) is responding to the request for public comment on issues related to the gas utility rate design study as published in the Federal Register, May 3, 1979, p.26055.

CMA is a non-profit trade association having 189 United States company members representing more than 90% of the production capacity of basic industrial chemicals within this country. Our member companies constitute the largest industrial consumer group of natural gas, and consequently, they have a vital interest in the rate design studies.

It is fundamental that the utilities be afforded a reasonable opportunity to recover their total costs. The rates must be high enough to sustain existing operations, and to provide for necessary expansion or replacement of facilities.

We believe that it is essential for gas utility rate design to be based on the principle of cost of service. The rates imposed on various classes of customers on a given distribution system should accurately reflect the respective costs of service. For example, rates charged to the residential class should reflect the cost of service supplied, and the study should comprehend the potential adverse cost impact to lower priority customers subject to curtailment schedules or interruptible service and incremental pricing policies.

We believe it is inappropriate for the Economic Regulatory Administration to undertake additional rate designs such as volumetric rates, lifeline rates and inverted rates because they are not authorized in the Public Utility Regulatory Policies Act of 1978. In our opinion, the expanded studies would not assist in rate reform. Inverted rates, under which per unit rates increase as consumption rises, are totally unjustified from a cost-of-service standpoint and they have the counterproductive effect of rewarding wasteful use by small consumers and penalize efficient use by larger consumers.

Lifeline rates, under which residential customers would receive a minimum quantity at a below-cost rate are discriminatory since they would force other consumers to subsidize the residential class.

We would welcome the opportunity to discuss our concerns with you in more detail.

Sincerely,

A handwritten signature in cursive script, appearing to read "Geraldine V. Cox".

Geraldine V. Cox, Ph.D.

UNITED STATES OF AMERICA
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

792217

Gas Utility Rate Design Study	)	
Responsibilities Under	)	Docket No. ERA-R-79-22
Public Utility Regulatory	)	
Policies Act of 1978	)	

COMMENTS OF THE
GENERAL SERVICE CUSTOMER GROUP

The General Service Customer Group,*/ pursuant to the Notice of the Economic Regulatory Administration (ERA) issued April 30, 1979 relating to its conduct of a gas utility rate design study required under Section 306(a) of the Public Utility Regulatory Policies Act of 1978 (PURPA), P.L. 95-617, submits the following comments.

GSC is an ad hoc group of gas distribution companies serving customers at retail in the States of Illinois, Indiana, Ohio, Michigan and Missouri. Because any action in this docket may provide support for subsequent legislative and regulatory proposals affecting retail natural gas rates, GSC members are vitally and directly interested in participating fully in this proceeding to assure that ERA conducts the study in the manner mandated by the statute.

Any communications should be addressed to:

J. Richard Tiano, Esq.
John R. Schaeffen, Jr., Esq.
Reid & Priest
1701 K Street, N.W.
Washington, D.C. 20006
Telephone: (202) 331-1752

*/ The General Service Customer Group (GSC) consists of Associated Natural Gas Company, Battle Creek Gas Company, Central Illinois Light Company, Central Illinois Public Service Company, Citizens Gas Fuel Company, Illinois Power Company, Michigan Gas Utilities Company, Missouri Utilities Company, Ohio Gas Company, Richmond Gas Corporation and The Toledo Edison Company.

1. Congress Intended That ERA's Study Be An Impartial Impact Study

The ERA Notice of Inquiry lists six "evaluative criteria" identified in Section 306(a)(2) of PURPA as "items" upon which various rate designs may have an effect. ERA states that it has identified the criterion of equitable rates to consumers as an additional "standard" with respect to which the rate designs must be analyzed. GSC considers ERA's choice of terminology unfortunate and potentially misleading. "Criterion" is defined as a standard on which a judgment or decision may be based. "Evaluate" means to examine and judge. Webster's Seventh New Collegiate Dictionary, (1965). An "evaluative criterion", therefore, is a standard by which the rate design would be examined and judged. GSC respectfully submits that Congress did not seek a "judgment" concerning the factors listed in Section 306(a)(1) of PURPA.

When Section 306(a) of PURPA is read in its entirety, it is clear that Congress sought an impartial analysis in the nature of an impact study of gas utility rate designs without value judgments. ERA's study mandated by Section 306(a) of PURPA should be a non-judgmental exposition of the impact of different rate design concepts on important items set forth in Section 306(a)(2). Contrary to ERA's Notice, the six items in Section 306(a)(2) are not standards, benchmarks or tests of quality. In short, they are not criteria nor were they intended to be. They are simply items which Congress intended to be studied. In passing Section 306(a), Congress did not establish a basis for determining whether the effect of one rate design concept is better or worse than another concept. Initially ERA is only charged with conducting and reporting the analysis. Only after the study is completed will ERA, consistent with Section 306(b) of PURPA, weigh and evaluate the merits of different rate designs and make proposals to "improve gas utility rate design."

These comments are not intended as an exercise in semantics. The Notice of Inquiry causes GSC genuine concern that ERA intends to conduct its study in an evaluative manner reporting its perceptions of the benefits and drawbacks, and thereby the desirability, of each rate design concept. GSC expects that the proposals and recommendations prepared pursuant to Section 306(b) will be products of an evaluative process. The report prepared under Section 306(a), however, should be expository and analytical as opposed to evaluative and judgmental. ERA is to report the effect, both separately and in combination of various rate designs as opposed to evaluating the rate design concepts in Section 306(a).

With this understanding of the task before ERA, it is apparent that ERA's additional standard i.e., "equitable rates to consumers" is an evaluative criterion and would lead necessarily to judgmental results. GSC strongly urges that ERA limit itself to reporting on the rate relationships between different customer classes under the various rate design concepts as envisioned by Section 306(a)(2)(B), without making any evaluative judgments on the equity of different rate design concepts.

While GSC strongly urges that ERA's report be entirely objective, GSC does believe ERA can usefully examine other issues in preparing its study. In approaching its task, ERA should be sensitive to the fact that each gas distributor has had a unique corporate development and its tariffs and rate schedules have been a product of an evolutionary process under the aegis of its respective state commission. It is axiomatic that, given the diversity of development of gas distribution systems, no single rate design can apply nationwide. Nevertheless, GSC suggests that ERA should add the following items to the list of "items" in Section 306(a)(2) of PURPA in conducting its study:

(A) Pipeline Tariffs - Some gas distributors purchase gas from multiple pipeline suppliers. Not only are the rate provisions of the pipeline tariffs dissimilar but also the curtailment provisions vary from pipeline to pipeline. The level of wholesale rates as well as the available supply from interstate pipelines bear directly on a gas utility's retail rate structure.

(B) Supplemental Supplies - With the gas shortage, interstate pipelines as well as gas distributors have had to rely upon propane, LNG, SNG and local production. These supplies have been generally more expensive than gas delivered from interstate pipelines. The mix of supplemental supplies available for retail distribution impacts direct upon the rate design of retail rates.

(C) The Role of Load Balancing Sales - Many distribution systems are designed to permit service to industrial loads to levelize the distributor's purchase load factor from its pipeline supplier. In part, the size of weather sensitive loads dictates the size of load balancing sales. Retention of these latter sales have the beneficial aspect of lowering rates to other customers and any new gas utility rate designs must continue to recognize this benefit.

(D) Storage - Because of their public utility duty to serve, some distributors have made significant investments in storage facilities. The role of storage and the associated costs have an impact upon the retail rate structure of these distributors.

(E) Annual Revenue Profile - It is evident that any rate design adopted will impact on the cash flow of a distribution company. For example, volumetric rates could create a shortage of cash during the summer months. To the extent that retail rate structures are modified, a distributor may be required to undertake additional borrowings to meet its payroll, construction budget, etc. Accordingly, any study of gas utility rate designs must analyze the revenue profile resulting from the adoption of a given rate design.

(F) State Statutes and Regulations - While the statutes applicable to gas distribution companies generally require just and reasonable rates, all state statutes and implementing regulations are not the same. Any study of gas utility rate design must be sensitive to this diversity.

The foregoing, additional "items" are obviously not an exhaustive list. GSC does respectfully suggest that ERA would be remiss to limit its study to the "items" contained in Section 306(a)(2) of PURPA.

2. ERA Must Provide For Continuing Public Comment on Its Rate Design Study

ERA has requested proposals as to the best method of providing for public participation in the preparation of the study, required by Section 306(d) of PURPA. GSC urges that ERA at the outset publish a workplan for the study. In addition, ERA should then hold informal public conferences in different regions of the country to permit the panel conducting the study to engage in discussion with gas distributors and other interested members of the public.

When a draft report has been prepared by the panel, copies should be sent to all parties that filed comments or participated in the public conferences. GSC recommends that ERA seek public comment on the draft report, both written and oral comments at additional regional public hearings. All written and oral comments on the draft report should be included as an appendix in the final report to Congress. This

would assure public participation in the study and would be consistent with the procedure adopted in the preparation of environmental impact statements.

3. GSC's Preliminary Comments on the Various Rate Designs

Consistent with GSC's recommendation that ERA issue a workplan for its study, GSC believes that such a plan should contain a preliminary analysis of the various rate design concepts. Accordingly, GSC presents some preliminary comments on the effect of these rate design concepts on the items listed in Section 306(a)(2) for inclusion in the aforementioned workplan.

(A) Incremental Pricing

Incremental pricing refers to the pricing of gas supplies to the consumers benefiting from those supplies at a rate greater than the standard rate by the difference between the gas purchase cost of that gas supply and the cost of system supply. Since incremental pricing can be expected to reduce pipeline and distributor load factors as large volume or load balancing customers switch to alternate fuels, incremental pricing may result in higher rates to present residential and commercial customers. It would appear to dampen demand for and consumption of natural gas, particularly industrial demand. Such a pricing mechanism not only implicates need for load balancing sales but also the annual revenue profile of a distributor.

ERA should be aware that Indiana has permitted incremental pricing of emergency gas purchases and the Ohio Public Utilities Commission has ordered incremental pricing of emergency gas purchases and volumetric propane. In contrast, the Illinois Commerce Commission has required that all gas purchase costs be rolled-in since all uses contribute to the system demand. This diversity, in part, reflects proper state concerns in setting rates for distributors.

Additionally, ERA should be aware that incremental pricing is inconsistent with cost-of-service rates since revenues from industrial customers exceed costs attributable to that class. Incremental pricing also adds a significant administrative burden to operating costs. Finally, State Commissions have recognized that increased gas costs to industry are ultimately borne by residential consumers in higher prices for manufactured goods. ERA should address these various issues in its study.

(2) Marginal Cost Pricing

As ERA knows, marginal cost pricing requires the gas company to forecast future costs, i.e., the additional cost of adding an additional unit of demand or consumption, and to price deliveries accordingly. Marginal cost pricing not only would require more extensive records with a resulting increase in operating costs but also could be expected to reduce the demand for natural gas, thereby increasing unit costs. To a large extent, distributors have built their systems to meet the needs of residential customers. Marginal cost pricing would discourage the addition of new high-priority uses since charges to such customers would reflect current construction costs. In GSC's view, it seems contrary to the public interest to discourage the high priority use of gas. Finally, marginal cost pricing would, however, increase competition with alternative fuels. It is difficult to assess whether this result outweighs the negative aspects of this rate design.

(3) Seasonal Rate Differentials

Seasonal rate differentials could be expected to increase distribution company load factors during the summer months. Rates to residential and commercial customers, who have a weak, inelastic summer demand, would be increased, while rates to industrial customers, who can increase summer production, would decrease. Seasonal rate differentials may also spur industrial customers to add additional work shifts during summer months, thereby increasing industrial consumption of gas. Adoption of seasonal rate differentials would accentuate the seasonal difference in end-use profiles.

GSC submits that seasonal rate differentials are unwarranted due to the availability of storage facilities. Unlike the electric utility industry, the natural gas industry can rely on storage facilities and need not meet the instantaneous demand directly from production. Since the unit cost of storage is considerably less than the unit cost of electric power production and related transmission facilities, any seasonal rate differential would not be justified by the increased administrative costs. Moreover, the availability of storage makes an Mcf in summer nearly as valuable as an Mcf in winter. It is clear that any consideration of seasonal rate differentials must take into account the impact that such a rate design has upon storage operations of distributors.

(4) Demand-Commodity Rate Design

A demand and commodity rate design would most accurately reflect cost-of-service by recovering fixed costs. Demand

metering of natural gas deliveries, however, is not practical. Accuracy in demand meters would be difficult to achieve and metering costs are prohibitive. Demand-commodity rates would increase distributor load factors, particularly during summer months, but high metering costs make this a less cost effective means of improving load factor than the development of storage. A demand-commodity rate design would probably reduce rates to industrial customers and increase their consumption of natural gas since they have greater control over their load factor and could better respond to the pricing signals. As noted above, GSC believes that ERA must be sensitive to a distributor's annual revenue profile. Demand-commodity rates would produce a flatter annual revenue profile.

Relatedly, GSC would note that a minimum bill, customer service charge or system charge functions in a similar manner to a demand charge. Such charges insure that a gas distributor recovers a portion of its fixed costs in every month but without the excessive metering costs. In developing its workplan, ERA should elicit comments on these types of charges.

(5) Declining Block Rates

Declining block rates are in common use and well-defined. Though they encourage consumption and make natural gas attractive to large volume users, they most accurately reflect the cost to serve customers. Use of declining block rates would not have significant effects on the natural gas industry in most jurisdictions since it is the prevailing rate design today. With the advent of natural gas curtailments, state commissions have begun to re-examine this rate design.*/
This trend**/ should be recognized in any ERA study and should be encouraged.

(6) End-User Rate Schedules

Although end-user rate schedules are not defined in PURPA, GSC understands such rate schedules to refer to the application of rates to different end uses as opposed to the traditional customer classifications--residential, commercial,

*/ NARUC, "The National Energy Act's Impact on State Regulation of Natural Gas Distribution Utilities: A Current Assessment", June 6, 1979.

**/ GSC would note that all gas retail sales in Michigan are made pursuant to flat rates ordered by the State Commission.

industrial. Some members of GSC have separate rate schedules for heating service or special large user rates for a unique end use. Utilization of such special rates are a reflection of the peculiar need for such a rate on that distributor's system. It is fair to say that there is no significant experience with end-use rate schedules. The effects of applying end use rate schedules generally would be largely speculative given the limited experience to date. ERA's workplan should elicit comments on this rate design to determine the extent to which such a design is used and the circumstances necessitating this rate form.

(7) Interruptible Service

Interruptible service is a well-defined term within the industry, referring to service which may be interrupted at the discretion of the distribution company during periods of increased gas demand. Interruptible sales provides distributors with a valuable mechanism in managing system gas demands. Interruptible service clearly improves the load factor of distributors and pipelines alike, thereby reducing operating and capital costs. While interruptible service does not significantly affect gas consumption, such service makes available for other purposes quantities of alternate fuel, generally oil. As the foregoing discussion indicates, ERA must be sensitive to the benefits of load balancing sales in its study.

(8) End User Consumption Taxes

End user consumption taxes, other than general sales and local excise taxes, are not in current use. To the extent that Congress contemplated different taxes for different end uses as pricing signals to discourage certain end uses, GSC submits that presently effective State curtailment plans are a more direct and effective means of achieving the desired result. If such taxes were perfectly applied they would have no effect on the natural gas industry other than a slight increase in administrative expenses to cover collection costs. In practice, however, it is not possible to structure such taxes in a manner which would have the same operational effect as present curtailment plans. Any meaningful comment on the effect of end user consumption taxes would require the development of a complex, defined tax structure. GSC would note, however, that any new tax would ultimately be passed on to consumers as part of the cost of goods. In any event, the propriety of any new tax is a matter to be addressed subsequent to ERA's study.

(9) Wellhead Pricing Policies

Wellhead natural gas pricing policies under Title I of the NGPA will probably reduce the demand for natural gas as retail gas prices approach the price of alternate fuels. Since price parity will occur first for industrial customers because of incremental pricing under the NGPA, the end use profiles of pipelines and distribution companies will shift to residential and commercial end uses as industry goes off the line. Congress expected ERA to consult with the FERC and GSC believes that this approach should be useful in preparing the ERA's study, especially with respect to the impact of the pricing structure mandated by the NGPA.

(10) Volumetric Rates

Although ERA's Notice does not define volumetric rates, GSC understands this rate design to provide for the same Mcf price to be charged to all retail customers. This rate design concept marks a significant departure from cost-of-service based rates. Rates based on cost of service would dictate different unit volume rates for residential, small commercial, large commercial and interruptible customers. Adoption of a rate design with a fixed unit volume price to all customers would discourage interruptible sales, reduce load factors, increase rates to all users as industrial customers left the system, decrease consumption of natural gas and cause wide fluctuations in the monthly revenues received by distributors. While GSC has no objection to the ERA's study of this rate design, GSC believes that ERA should clearly define this rate design concept to elicit meaningful comments because of the potential harmful consequences caused by this rate form.

(11) Lifeline Rates and Inverted Rates

Inverted rates are the opposite of declining block rates--unit cost of gas increases with usage. Lifeline rates are similar in form and effect to inverted rates. A specified volume of gas is sold at a flat rate below cost, and consumption beyond the lifeline amount is priced above cost to recover revenue deficiencies in the initial block.

Inverted rates would discourage natural gas consumption and would shift end use profiles away from industrial uses. Inverted rates would also lead to lower load factors and increased competition with alternate fuel. Industrial customers would be encouraged to purchase limited low cost blocks of gas and then switch to alternate fuel as the unit cost increases with consumption, resulting in a low load

factor. Under declining block rates, by contrast, such customers are encouraged to purchase their full requirements at high load factor because of the decreasing unit commodity costs.

Inverted rates would also create the potential for large variations in monthly revenue and under- or over-recovery of costs. Fluctuations in weather and business conditions as well as efforts at conservation will have significant impact on monthly consumption, and inverted rates will magnify the effect on revenues. The under- or over-recovery of costs resulting from inverted rates will also cause cross-subsidy among and within customer classes. Lifeline rates likewise would cause cross-subsidy among customer classes.

In its study ERA should attempt to elicit information concerning the response of the various state commissions implementing inverted and lifeline rates. With respect to lifeline rates, GSC would note that, the States of Ohio and Indiana have adopted schemes which more directly and, in GSC's view, more properly involve the government in achieving the social welfare result intended by lifeline rates. In Ohio, for example, all persons over the age of 62 with incomes of less than \$7200 are eligible for energy assistance. The State government processes claims for eligibility under the program and the State pays 25% of an eligible user's bill from the general tax revenues. GSC submits that this is a far better method for implementing this social policy than lifeline rates. GSC would further note that several states have lifeline rates under evaluation. The results of these state proceedings should be incorporated into ERA's study.

CONCLUSION

GSC earnestly hopes that ERA in this docket will produce an objective study for presentation to the Congress. The suggestions made in these comments would further this goal. GSC is firmly convinced that there must be a full opportunity for interested parties to participate in the development of the study on gas utility rate design. In submitting these comments, GSC has attempted to identify some of the subsidiary issues that must be addressed by ERA. These issues should be set forth at the very outset in a workplan in order to achieve a meaningful and thorough study of gas utility rate designs.

Changes in rate design at the retail level can cause irreparable harm to distributors and consumers alike. Accordingly, GSC strongly suggests that ERA approach its task not only with restraint but with an appreciation that local regulatory authorities have been sensitive and attentive to the matter of rate design. Because of these efforts, GSC hopes that ERA's study will conclude that the purposes of Title III of PURPA are matters best addressed by state regulatory commissions.

Respectfully submitted,

GENERAL SERVICE CUSTOMER GROUP

By

J. Richard Tiano
Its Attorney

July 2, 1979

UNITED STATES OF AMERICA
 BEFORE THE
 DEPARTMENT OF ENERGY
 ECONOMIC REGULATORY ADMINISTRATION

732218

Gas Utility Rate	)	
Design Study:	)	
Responsibilities Under	)	Docket No. ERA <u>79-22</u>
Public Utility Regulatory	)	
Policies Act of 1978	)	

COMMENTS OF
 LOUISIANA GAS SERVICES, INC.

Louisiana Gas Services, Inc. (LGS) hereby submits its comments in response to the Notice of Inquiry in the above-captioned docket, published in the Federal Register for May 3, 1979.

I.

Notices and correspondence concerning these comments should be sent to:

Richard A. Faust, Esq.
 Secretary and General Counsel
 Louisiana General Services, Inc.
 1233 Westbank Expressway
 Harvey, Louisiana 70058

and

D. Jane Drennan, Esq.
 McDermott, Will and Emery
 Suite 1201
 1101 Connecticut Avenue, N. W.
 Washington, D. C. 20036

II.

LGS is a Louisiana Corporation, organized in 1970 as successor to the Louisiana Gas Service Company, originally incorporated in 1956. The principal subsidiaries of LGS are Louisiana Gas Service Company, a gas utility serving approximately 235,000 residential customers, and LGS Pipeline, Inc., Inc., serving more than 300 industrial customers in suburban New Orleans and northern Louisiana. LGS' service to residential consumers is regulated by the Louisiana Public Service Commission; its service to industrial customers is non-regulated. As a regulated supplier of natural gas to residential consumers, LGS would be directly affected by legislation altering present utility rate designs. To the extent that legislation would effect LGS' pipeline supplier, LGS' non-regulated activities would be directly affected by legislation arising from this study.

III.

Section 306 of the Public Utilities Regulatory Policies Act (PURPA) requires the Secretary of Energy to study and report to Congress on gas utility rate design, after consultation with the Federal Energy Regulatory Commission (FERC), state regulatory commissions, gas utilities, and gas consumers. As required by §306(a)(1) of the Act, that study should consider the following: incremental pricing; marginal cost pricing; end user consumption taxes; wellhead natural gas pricing policy; demand-commodity rate design; declining block rates; interruptible service; seasonal rate differentials; and end user rate schedules. Section 306(a)(2) states that these rate designs

and pricing policies should be studied to determine their possible effect on: (A) natural gas pipeline and local distribution company load factors; (B) rates to different classes of end-users; (C) the change in total cost to gas consumers resulting from gas utility designs; (D) demand for, and consumption of, natural gas; (E) end use profiles of natural gas pipelines and local distribution companies; and (F) competition with alternate fuels. Title III of PURPA is generally intended to encourage conservation of energy supplied by gas utilities, optimization of the efficiency of the use of facilities and resources by gas utility systems, and equitable rates to consumers of natural gas. Section 306(b) of the Act specifically requires the Secretary, Department of Energy, to develop proposals to improve gas utility rate design and to "encourage conservation of natural gas."

The Economic Regulatory Administration (ERA) in its Notice of Inquiry, 44 F.R. 26055 (May 3, 1979), indicated that it would consider three additional pricing systems: volumetric rates, lifeline rates, and inverted rates. ERA also indicated that it was adding a new criterion for evaluation of the rate design proposals: equitable rates to consumers.

LGS submits these comments with the specific understanding that it will be afforded an opportunity for further comment on the gas utility rate design study, as stated in paragraph II.4 of ERA's Notice of Inquiry (44 F.R. 26055).

LGS also reserves the right to offer comments on any specific regulatory or legislative proposals. At this point, rather than commenting on all aspects of the rate design study, LGS would like to offer the following general comments.

The solicitation of comments as to the three additional pricing systems could be interpreted as an indication in ERA's Notice of Inquiry that ERA officials are considering using the rate design study to advocate pricing systems that would subsidize residential consumers of natural gas at the expense of industrial consumers. Such action would conflict with national energy policy and would not serve the interests of any group of natural gas consumers.

It is presently the policy of the Department of Energy (DOE) to reduce dependence on foreign oil imports and to transfer demand away from refined oil products to natural gas, propane and coal. [44 F.R. 5815 (Jan. 29, 1979)]; Price and Supply Situation of Middle Distillates: Hearings before the Subcommittee on Energy Regulation, Committee on Energy and Natural Resources, (Statement of John F. O'Leary, Deputy Secretary, U.S. Department of Energy, June 25, 1979.) Most industrial consumers of natural gas have dual fuel capability. Increased natural gas prices for industrial consumers would lead those consumers to switch from gas to oil consumption, a movement that would only exacerbate the current oil shortage.

DOE should not favor price controls or pricing systems that fail to reflect the actual cost of fuel supplies. Rate designs which artificially suppress the true cost of natural gas to

certain ratepayers would only result in misallocation of resources. Congress has already moved to deal with this kind of problem in the Natural Gas Policy Act of 1978 (NGPA), mandating decontrol of gas prices by 1985. To the extent that low-income families need public aid to pay high energy costs, such aid should be provided through income assistance programs rather than through distortion of rate and price structures.

Attempts to increase the price of natural gas as consumption increases will not aid low-income families. The energy consumption of low-income families is likely to be as high or higher than that of middle-or high-income families; demand is inelastic; low-income families spend a higher proportion of their total income on natural gas than do high-income groups. Price schedules that impose rising rates on residential users, would be regressive in terms of income distribution.

Because the cost of transporting natural gas involves a high proportion of fixed costs, declining block rates as presently applied to industrial consumers probably best approximate actual marginal cost. After the initial fixed costs of supplying industrial consumers are paid, the marginal costs of delivering more gas to those consumers probably decreases. The declining block rate system then best indicates the actual cost of continued gas supply and gives the most accurate price signal to consumers for efficient allocation of resources.

It is important to retain industrial consumers on gas pipeline systems. Fixed costs are a much higher proportion

of total costs for residential consumers than they are for industrial consumers. With industrial consumers on the utility systems, those fixed costs are spread to the industrial users, reducing costs for residential consumers. Industrial consumers of natural gas now actually subsidize natural gas consumption by residential end users. The high load factor gained in industrial consumption also allows utilities to balance supplies and allows them an opportunity to store gas during summer months for winter residential demand, if necessary. These three benefits -- fixed cost recovery, load balancing, and underground storage incentives -- would all be reduced or lost if industrial consumers of natural gas were forced out of the utility systems by higher prices. Industrial demand for natural gas is relatively elastic while residential demand is relatively inelastic. Attempts to subsidize residential consumers at the expense of industrial consumers would probably force industrial users out of natural gas utility systems, leaving residential consumers to bear a greater burden of natural gas supply costs. The long-term effect of "subsidizing" residential users is then likely to be higher gas prices for the average home-owner. The goal of developing equitable rates to consumers surely would not be advanced by that result.

CONCLUSION

Attempts to promote "equitable rates to consumers" by subsidizing residential consumption of natural gas at the expense of industrial users are likely to be self-defeating. Such action would exacerbate problems caused by the current oil shortage and would conflict with current national energy

Current rate structures reflect marginal cost pricing as closely as is practical. Attempts to impose rising price schedules would result in high administrative costs and would be regressive in terms of income policy. It is important to retain industrial consumers on gas utility systems because those consumers pay a substantial portion of the fixed costs of the utilities and allow load balancing and underground storage for the benefit of residential consumers. Forcing industrial users away from natural gas consumption by raising prices, in an attempt to subsidize residential consumers, would only reduce the efficiency of utility operation and increase the cost of gas supplies for home-owners.

Respectfully submitted,

D. Jane Drennan
Attorney

Dated: July 2, 1979
Washington, D. C.

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

before the

Economic Regulatory Administration

Gas Utility Rate Design Study)

Docket No. ERA-R-79-22

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OFFICE

COMMENTS OF
THE BROOKLYN UNION GAS COMPANY

The Brooklyn Union Gas Company (Brooklyn Union) is a New York gas utility and a member of Associated Gas Distributors (AGD). Brooklyn Union joins in the comments submitted by AGD in response to the Notice of Inquiry in this proceeding, and adds the following supplementary comments on certain issues herein presented:

SPECIFIC RATE DESIGNS: FULLY ALLOCATED COST - AND VALUE OF SERVICE - BASED RATES

To Brooklyn Union, the most prominent and disturbing omission in the catalog of rate design methodologies to receive consideration in this study, is the absence of rate design based on fully allocated costs and value of service. Fully allocated costs, as modified by value of service concepts, are not merely one, out of many other, equally consideration-worthy techniques for the design of gas utility rates: cost based rates, with fully allocated costs of service as the overall rate foundation, and value of service as determinative of particular rate ceilings, are and have been the bedrock of gas utility

rate design since the inception of modern utility regulation.

Cost based rates have not only the imprimatur of long acceptance and application by the gas utility industry, but the sanction of the most respected experts in the regulatory field. As Professor Bonbright has stated

"Nevertheless, one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike -- the standard of cost of service ... True, other factors of rate making are potent and are sometimes controlling -- especially the so-called value-of-service factor in the determination of the individual rate schedules. But the cost standard has the widest range of application. Rates found to be far in excess of cost are at least highly vulnerable to a charge of 'unreasonableness.' Rates found well below cost are likely to be tolerated, if at all, only as a necessary and temporary evil." Principles of Public Utility Rates, 1969 edition, page 67.

Moreover, a rate structure based on fully allocated costs, as modified by value of service considerations, is the only rate design readily capable of meeting, without distortion, the revenue constraints and non-discriminatory standards of most, if not all, state regulatory statutes. Such a rate structure will automatically satisfy these statutory criteria without giving rise to the administrative nightmare of cross subsidies and refund and/or surcharge requirements that appear to be an inescapable adjunct of any other, exotic, system of utility rate design.

Further, it has now been established beyond dispute

that rates based on fully allocated costs, as modified by value of service considerations, are entirely capable of serving the principal purpose of Title III of PURPA, to encourage the conservation of energy supplied by gas utilities. The evidence in support of this conclusion is the fact that a tremendous amount of conservation by customers of gas utilities has actually occurred in the past several years, despite the fact that most utility rates have continued to be based, during this period, on fully allocated costs and value of service principles.

Still further, the PURPA objectives of conservation and optimization of the efficiency of the use of facilities and resources by gas utilities are by no means solely dependent, for their achievement, on utility rate design. These objectives can be promoted, and probably more efficiently, by other direct measures, rather than through the indirect and circuitous means of exotic utility rate structures. The pervasive statutory requirements for just, reasonable and non-discriminatory utility pricing, on the other hand, can only be satisfied by the application of rate design techniques appropriate to produce those results.

Finally, any federally-mandated departure from historic and traditional gas utility rate design methodologies, if such departures should ultimately be mandated, can be justified only on the basis of "a reasoned explanation" for the departure. Columbia Transmission Corp. v. FERC
 _____ F.2d _____ (D.C. Cir. No. 77-1627, May 17, 1979).

Brooklyn Union submits that no such "reasoned explanation" can be developed unless the traditional methodology is given adequate consideration and found, in some manner or respect which is not presently apparent, to be demonstrably inferior to any alternative methodology, not only insofar as conservation and optimum utilization of facilities and resources are concerned, but also in ability to assure the consuming public of just, reasonable and non-discriminatory gas pricing.

EVALUATION CRITERIA: PIPELINE RATE DESIGN

Brooklyn Union believes that an essential evaluative criterion, in addition to the criteria enumerated in the Notice of Inquiry and suggested in the comments of AGD, is the relationship between any rate design methodology considered for application to gas utility pricing and the rate design methodology authorized or allowed for gas pipeline pricing. In some circumstances, although not necessarily every case, an inconsistency between pipeline and utility rate design could not only defeat the intended purpose of the utility rate design, but produce results even more damaging than the condition intended to be corrected.

In fact it would appear that the logical starting point for the implementation of the stated goals of Title III of PURPA would be at the pipeline, rather than the utility, rate design level. There can be, for example, no more effective way to promote conservation, optimization of the efficiency of the use of gas facilities and resources, and

equitable rates to consumers, than the restoration of Atlantic-Seaboard based rate design (or even a less tilted rate design) for gas pipelines to encourage high load factor operations on all gas facilities and the development of storage to conserve gas supplies.

Even if, however, the scope of the present study is directed specifically to gas utility rate design, it must be recognized that utility pricing cannot be considered in a vacuum, because its ability to promote the goals and objectives of PURPA is highly dependent on the rate design employed in pricing the gas that utilities must purchase from pipelines for resale to their customers.

Respectfully submitted,

The Brooklyn Union Gas Company
195 Montague Street
Brooklyn, New York 11201

By: Cullen and Dykman

Cullen and Dykman
Its Attorneys
177 Montague Street
Brooklyn, New York 11201

Of Counsel

Barbara M. Gunther

Dated: June 29, 1979

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CHARLES H. FRAZIER
DIRECTOR, PHILADELPHIA OFFICE

June 28, 1979

Mr. Jerry L. Pfeffer
Acting Assistant Administrator
for Utility Systems
Economic Regulatory Administration
Department of Energy
2000 M Street, N.W.
Washington, D.C. 20461

Dear Mr. Pfeffer:

This is written pursuant to ERA's Notice in the Federal Register of May 3, at page 26055, with respect to your Agency's study called for by Title III, Section 306 of PURPA. Under Section II of that Notice of Inquiry you seek general comments with respect to the subject matter and coverage of the study. This is a matter to which we have been directing our attention for several years now. Aside from assignments from various clients, I have served on the Rate Design Committee of the National Gas Survey, during 1976-1977, and authored Chapter 3 of its Report¹ (copy of which I am enclosing). In the light of your Inquiry, I have reread this chapter and note that, unfortunately, very little progress toward rational pricing has been made since it was written. A few of the figures are no longer current, of course, but everything that was said in this chapter is still valid today. I could edit it of course, but I am sending it as is, to emphasize the somewhat durable character of the ideas.

The issue posed in this chapter is still the one which must be met by DOE-ERA in the subject study--namely, whether reliance for coping with the "gas shortage" (if one may still use this word--and it is still valid in the longer run sense) should be based on a rationing system (a federally-administered scale of priorities) or on a system of economic pricing--a balancing of demand with supply. Essentially the

¹ National Gas Survey, Report of the Transmission, Distribution and Storage Technical Advisory Task Force--Rate Design, to the Federal Power Commission, May 1977.

Mr. Jerry L. Pfeffer

June 28, 1979

imbalance between demand and supply is now, as it has been for the last ten years, one of restraining, by Government fiat, demand for what we may call boiler fuel uses, in contrast to uses where the form value of gas is significant. If the economically correct policy is adopted, of pricing gas sold for these former uses at a reasonable approximation of its replacement cost, the Inquiry can reasonably proceed with the detail of exactly how this should be done; but the decision must first be made by DOE and FERC that it should be done; the solving of other detailed rate design issues raised in the Notice all would flow from this decision.

Unfortunately, both DOE and FERC are still struggling in the rationing mode. A new system of priorities is being fashioned, and each new "study" that we read about emerging from DOE-FERC seems to assume the continuation of this mode. There is little or no observable progress in FERC in the direction of adopting economic pricing for wholesale sales--the one place where its statutory power² would make this effective. This is despite the fact that the necessity of moving to marginal cost pricing is recognized throughout PURPA and indeed throughout the whole package of the National Energy Acts. I would suggest that both Goal 2 of Title III of PURPA, "the optimization of the efficiencies of the use of facilities and resources of gas utility systems" and the similar provision of Title I of PURPA with respect to electric systems,³ makes it clear that economic efficiency--including its reflection in fostering conservation--is elevated to a prime goal of ratemaking. Thus the missing part of the Rate Design Study of 1977, giving statutory authority to the adoption of this goal, is now in place.

In the light of this situation, it seems to me that what is required at this point is a hard administrative decision to make progress toward that goal. We would submit that this progress can be more rapidly achieved if this policy decision is reached first--i.e., that this is the way you want to come out. All the various detailed questions of rate design as to which you are gathering information,

² The decision by the D.C. Circuit last month, in Case No. 77-1627, remanding a rate design issue to the Commission, does not go to whether the Commission has this power but whether its reasonable adoption of mild steps toward economic pricing (moving away from Seaboard) was justified in the record and adequately explicated.

³ Oil pricing is of course already moving marginally.

Mr. Jerry L. Pfeffer

June 28, 1979

and which are listed as "evaluative criteria,"⁴ are side issues until this basic decision is reached. Would it not be a good idea to reach this decision in a prompt rulemaking proceeding, including the adoption of general Standards, and then permit the detailed study of specific rate designs to proceed with some policy guidance? I hope you will agree that the underpinning for such a rule is provided by the attached document, which not only furnishes the rationale for marginal cost pricing but also proceeds to delineate with considerable specificity exactly how one would go about implementing the program.

I would only add that the problems always confronting ratemaking, that is, conforming theory to practice, are of course still present. Swinging present rates into the new mode will require a phasing-in process. Revenue stability of the various pipelines and distributing companies will have to be considered, as will the precept of continuity in ratemaking. The issues being raised in the incremental pricing rulemaking docket (RM79-21) will be present here. But once the decision in principle is reached, all these can be worked out on a case-by-case, site-specific basis. Indeed a part of the inquiry could be the taking of certain specific, illustrative situations and working out such detail (an area to which we have addressed ourselves--most recently in a Madison Gas & Electric Company gas rate proceeding).

If there is any receptivity to the thoughts offered herein, we will of course be delighted to be helpful in any way we can, expatiating on them in such a mode as you find most convenient.

Sincerely yours,

CHF:nhc

Enc.

cc: Dr. Irwin M. Stelzer

P.S. In my absence, and if Irwin Stelzer is unavailable, Jerry May, of our New York office, is fully aware of our work in this area.

⁴ Much of which is well covered in the 1977 report.

MARGINAL COST PRICING: ITS THEORY AND APPLICATION

Shortage is, of course, a state in which demand at the prevalent price level exceeds supply.

It may be said that shortage may be "cured" by rationing on the one hand or rate (price) action on the other. The goal is to reduce the quantity demanded and enhance the supply until balance is reached. In the period prior to 1977, most attention has been devoted to the "rationing" method.

This chapter seeks to examine some theories as to what may be done on the price side, assuming rationing offers an inadequate solution.

Demand and Supply Must Come in Balance

Few seers, from the industry to the Federal Energy Administration, believe that there is no need even in the longer run (i.e., the next two decades) of causing demand to shrink to a point where it will be in balance with potential supply. It will take virtually all of the natural gas and all the likely supplemental supplies available between now and 1985 to achieve the most conservative "requirements"¹ target for 1985, permitting any growth at all. This achievement would be possible only because demand, particularly

1. A term of the art in the gas industry implying demand under some system of likely price assumptions.

in the industrial class but also elsewhere, now is being severely constrained--not by price, but largely by government action.

Two Choices: Rationing or
Pricing Changes

The question is how the demand/supply balance can best be achieved in the long run. It would seem that, basically, there are only the two choices suggested above. The first choice is to continue down the present path of having the Federal government (with some assistance from the states) prescribe the permitted uses for gas.

The end of this path could see the allotment to each company of the supply it will be permitted and, in effect, the substitution of a Federal "controller" for company (or industry) supply planning.

Pricing to Allocate Supplies

The second choice is to let price take over the allocation function it used to serve, largely in pre-natural gas days, and so let the marketplace direct gas to the uses and users for whom it is most valuable.

The government rationing role needs little elaboration for those who have followed what has been happening in the last few years. Each major curtailment decision seems to be more complicated than the last, and the special relief route continues to proliferate. The outcome is, of course, by no means clear.

Many Questions Face Us

Will FPC feel it needs, by indirection, to take control of supplemental sources as well as the traditional natural gas sources, reducing, for example, natural gas allotments where a company has been foresighted enough to do something for itself? The FPC now tentatively says no, but with more severe curtailment will that logical judgment prevail?²

Will all growth be stopped, as the trend seems to be in FEA thinking? Will some system of "grandfathering" be adopted, making allotments go along with the customer or the premises? Will a system of industrial curtailment proceed further to develop a more finely graduated system of priorities, specifying in great detail how and where gas should be used in industry? Using what criteria as to value of society? Will residential use continue to be protected over industrial use? This, even though, as appliances wear out, substituting another energy source may not become that much of a hardship? In all fairness, should not rationing be applied to the intrastate market, extending FPC control? The list of value judgments confronting the government regulator seems limitless.

2. Cf. FPC Opinion No. 778 in re Transcontinental Gas Pipe Line Corporation, Docket No. RP72-99.

Problems of "Rationing by Price"

The rationing-by-price choice is also not without its problems. How would it work? The economist says that, if prices are set at marginal cost, scarce resources will be allocated most efficiently. What is the marginal cost of gas? How will gas be priced to different types of users so as best to preserve the marginalist concept, considering the real world of overall earnings restraints imposed under regulation on the pipelines and the distributors (if not the producers)?

How will the requirements of economics be balanced against perceived notions of equity, the latter emphasizing continuity in contrast to abrupt changes in price? What about "second-best" considerations? The list of questions is long, but suggested answers may be offered. Certainly, the assignment to this Task Force calls for an in-depth analysis of the role of price and, hence, also of marginal cost pricing.

Marginal Cost Pricing in the
Regulated Utility Context

While the basis for, and use of, marginal cost in pricing is not entirely new, its explicit consideration in the context of the gas industry is of very recent origin. For years, little attention was paid to the matter: rates were coming down, earnings were going up and rate structure was of interest only to engineers and commission staffs whose

principal concern was equity. Not too many states required formal cost-of-service studies by customer class. Those that did, rarely attempted formally to relate those fully allocated costs to rates so as to secure equal rates of return by customer class. No attention was paid to questions of allocative efficiency, at least not in a systematic way. However, the economists' espousal of marginal cost pricing was reflected in many of the so-called promotional, interruptible and off-peak rates which existed.

What "Marginal Cost" Is

The economic theory underlying marginal cost pricing, simply stated, is that efficient resource allocation can be achieved by designing rates to reflect cost--read marginal cost. This concept refers to the cost of additional production and includes all costs borne at the margin, whether incurred by the producer or society (although the latter creates special problems).

As generally developed in a series of electric utility cases, the term marginal cost³ came to refer to the cost of providing additional blocks of service, which were expected to be sold on a continuing basis. It is a well-established principle in economics that, when prices of goods and services are set equal to their respective marginal cost of production, there results a socially optimum allocation of

3. For a definition and discussion of marginal cost, see Appendix A.

resources. This gives a situation in which each resource is being put to its highest value use, with a consequent maximization of satisfaction yielded by these limited resources.

A Basis for Consumer Decisions

When price is equal to marginal cost,⁴ the consumer, who is deciding whether to make a single purchase of an additional unit of the product, is essentially comparing what that additional unit of product would be worth to him with what it costs society to produce that additional unit. Obviously, the consumer in such a circumstance will not purchase additional units of a commodity whose cost of production exceeds the value to him. But, so long as the value to him is greater than the cost of producing additional units, he will continue to increase his consumption, thereby increasing his economic welfare. Thus, consumers' buying decisions will be guided by the correct price guidelines.

It should be noted that marginal (or incremental, a term more frequently used in respect to public utilities) cost pricing makes no distinction as to whether a customer is new or old. All customers are equally responsible for the most expensive (marginal) output. All should be charged the same marginal cost price, except insofar as marginal costs of service might differ.

4. Attachment A hereto discusses the difference between long- and short-run marginal cost. In this chapter, the concept is one of long-run marginal cost, in which is included the capital cost of bringing facilities into balance with demand at the conclusion of the planning period.

Marginal Cost Effects on Revenue

Pricing at marginal cost may produce revenue which exceeds or falls short of the revenue requirements of the utility, as determined by regulatory commissions according to accepted practice developed over past decades. Fortunately, however, there is a well-established body of economic theory⁵ which tells us how rates should deviate from marginal cost so as to get the most efficient allocation of resources, while generating only the approved amount of revenue, the so-called inverse proportionality rule. Simply put, this states that, where marginal cost is higher than the commission-found average cost,⁶ all rates should be below their respective marginal costs.

However, in those markets where the demand is most elastic, i.e., most responsive to price, the price should come closest to marginal cost to minimize the encouragement of growth in demand at rates which do not cover the value of the resources consumed. In markets where the demand is less elastic, the rates should correspondingly be that much lower than marginal costs because in these markets lower rates will least encourage uneconomic consumption.

5. Footnoted in Appendix A.

6. In this chapter, it is assumed that present regulatory standards for fixing revenue realization remain. Moreover, while we now assume marginal cost to be above average cost, as it now generally is, the reverse condition has existed, and provisions to cope with that situation, using the same concepts discussed herein, could be devised.

Should a Consumer Credit Be Given?

There is another type of methodology which may also be useful as an alternative to the proportionality theory. Under this alternative, all rates would be set based on marginal cost. As a next step, a form of credit would be paid to all consumers which would reduce their total outlay to that found by the regulatory commission to be "just and reasonable." Under this theory, the only rule is that the method of distribution of the credit to the consumers should not affect the consumers' choice or use of the fuel. In other words, it cannot be directly related to consumption; it must be neutral, economically speaking. In theory, of course, it could even be by lottery, to use an extreme illustration.

The practical method which could be expected to receive regulatory sanction is that the credit be related to the size of the customer's outlay in some base period-- a fixed amount (although perhaps only until the next rate case). Thus, a customer could not count on the dividend as varying with the amount of energy used, since the dividend is fixed. Instead, he would have to consider the cost of that energy to him to be the marginal cost, as reflected in the basic price, since this is the cost by which increments (or decrements) in use would be priced.

Using Taxes to Avoid Excess Revenues

This list of alternative balancing methods would not be complete without mention of a third possibility, although this is beyond the purview of a regulatory commission. This is to fix rates at marginal cost and then design an appropriate "excess earnings" tax to satisfy considerations of equity. This has the advantage of simplicity--at least at the pricing level--although the continuity in rate-making precept could be shattered. At least at the producer level, the higher price, accompanied by a properly designed tax, would have the greatest supply enhancing effect.

The marginal cost pricing theory has now been presented in many electric rate cases and its application is achieving increasing (although by no means universal or ungrudging)⁷ acceptance. It will, in one way or another,

7. It has been argued that, if one industry fails to have incremental pricing, then we cannot tell whether it is desirable from the standpoint of economy-wide efficiency for others to have it. See R. G. Lipsey and K. Lancaster, "The General Theory of the Second Best," Review of Economic Studies, Vol. 24 (1956-1957), pp. 11-32. This argument has been shown to be incorrect. The only situation in which the pricing policies in one industry could render uncertain the effect of incremental cost pricing in another is where products are technological substitutes in production, or utility substitutes in consumption. See O. A. Davis and A. E. Whinston, "Welfare Economics and the Theory of the Second Best," Review of Economic Studies, Vol. 32 (1965), pp. 1-14. Even Davis and Whinston's position is too restrictive. Incremental cost pricing is justified, even for substitute commodities, as long as the dynamic path of adjustment for each commodity in sequence leads toward a simultaneous equilibrium of incremental prices for all such commodities. In any event, in terms of current energy prices, it is reasonable to consider that oil prices are so priced, in terms of cost to America, that new gas field prices are so priced, and that electricity prices are tending in that direction.

provide the underpinning for a variety of new electric rate forms, including time-of-day rates.

Many Problems Need Solving

There are, of course, complex problems yet to be solved, particularly in moving from the concept of marginal cost pricing to its application. But it seems safe to assume that, one way or another, electric utility rates will, before long, reflect these economic principles, at least partially. It is not coincidence that what might be termed "business principles" are also satisfied, in that new business is not being taken on at less than cost, the effect, in contrast, of average cost pricing.

What has this to do with the gas business? First, as already noted, economists and other perceptive observers have pointed out that what was sauce for the electric goose was sauce for the gas gander; it was their way of at least partially coming to grips with the "second best" problem. Second, the environmentalists have already argued that marginalist principles are applicable to the gas industry and urged the adoption of "tariffs which reflect the marginal cost of providing natural gas at various seasons and places and conditions of service."⁸ Third, state commissions have begun to ask the industry, in the words of one chairman,

8. Testimony of Ernst R. Habicht before the Iowa State Commerce Commission, re People's National Gas Division of Northern Natural Gas Company, Docket No. U-546, January 9, 1976, mimeo p. 5. This point of view has been placed before this Task Force.

"to confront the varying implications for demand prospects of incremental cost pricing on the one hand and rolled-in average embedded pricing on the other hand."⁹ Finally, while the problems of application to the gas industry are difficult, the lessons of marginalism appear applicable to it.

A Practical Application of Marginal Cost Pricing

In the application of marginal cost pricing to the gas business, there are a number of reasonable questions which must be answered on a practical, rather than a theoretical, basis. In what follows, the potentially viable solutions are the ones offered, keeping in mind the end goal of economically efficient pricing in contrast to the theoretically "correct" instant solutions. Progress toward this end goal is what is sought in the least disruptive fashion.

There are three levels at which pricing must be considered: the cost of gas supplies sold by the supplier of that gas to the pipelines; second, the schedules of charges between the pipelines and their distributor customers (the particular concern of the Federal Power Commission); and, finally, the pricing by the distributors to the end-use markets. In each of these areas the appropriate definitions

9. New York State Public Service Commission, Proceeding on motion of the Commission as to the long-range plans of New York State's Gas Distribution Companies, Minutes of March 17, 1976, Prehearing Conference, p. 16.

of marginal cost may vary and the techniques of application be sufficiently different so that no general prescription is possible.

Marginal Cost Pricing by the
Producer/Supplier

First, let us turn to the marginal pricing of gas by the supplier (or producer). Here, marginal cost pricing is the rule¹⁰ rather than the exception. For about 20 years now, in terms of the producer charges under new gas contracts, marginal cost pricing has been followed, in that each

10. But preexisting contracts have not been revised to adopt the prices established by the new contracts. In this respect, we have not had pure marginal cost pricing, which consists of setting all prices at the costs of the marginal supply, as is done in unregulated crude oil markets. This is not to recommend that existing contracts be abrogated, but only to note that as long as they maintain prices below the cost of marginal supply we will not have achieved complete marginal cost pricing. Full marginal cost pricing of natural gas supplies can be expected to produce substantial increases in the net revenues of "old gas," just as it would in the absence of price controls for "old oil." There are several options open for policy in this connection, none of them mutually exclusive (presumably requiring legislation). First, to the extent that existing contracts continue in force, the "windfall" to suppliers will be reduced. Second, there is no need to introduce marginal cost pricing instantaneously. It can be phased in over a period of, say, five years, with the gap between marginal costs and the price of "old gas" at the beginning of the transition reduced by increasing fractions over the same time. This would moderate any capital gains to suppliers from increases in the price of reserves. Third, windfall gains could be recovered by a tax designed especially for the purpose.

new natural gas contract was based (theoretically, at least) on an approximation of marginal cost (although there may be a real question as to whether the new gas price kept up with the times).

Furthermore, the FPC has, admittedly in a somewhat gingerly fashion, adopted marginal cost pricing in respect to other gas supplies being sold to the pipelines, notably the first SNG plants (Columbia's Green Springs plant and Algonquin's Freetown plant) and, at least in its first decision, El Paso's sale of LNG to its three pipeline customers. Theoretically, in each of these instances (with the exception of the time lag problem referred to above), it may be assumed that the pipeline's decision as to its purchase program was guided by economically correct teachings as to what the current (marginal) costs of the various supplies are.

Here it seems that the application of marginal cost pricing simply follows common sense.

Marginal Pricing by Pipelines

Let us turn now to a much more difficult problem: marginal cost pricing of a pipeline's supplies to its distributing company customers. Here we run into truly difficult definitional problems.

What is the marginal cost of gas to pipelines (and distributors)? The future supplies of gas are such that there is at no time a smoothly, continuously upward rising marginal cost curve with each new element of incremental supply costing slightly more--the sort of illustration used in discussing marginal cost application.

The first problem is a pragmatic one: data on natural gas discovery are not adequate to relate potential incremental gas discoveries to price changes. Hence, they cannot be used safely to construct a marginal cost curve for natural gas itself. The producing industry has vigorously resisted constructing such a curve for years, despite challenges to do so. The fact is, however, that, even if such a curve could be constructed (and model builders have tried), according to anyone's computations, it might be of limited use, since, long before the almost infinite cost of the last Mcf of natural gas was reached, supplemental supplies would be phased in.

New or Supplemental Sources for Gas

This raises the second problem: the varied and unpredictable nature of the timing, potential volume and cost characteristics of those supplements; LNG purchased from abroad; gas imported from Alaska; gas imported from the Canadian Arctic; the gas potential of relatively untried

extraction methods; gas manufactured from coal; gas manufactured from oil; and, since it is in a slightly different category from the traditional supplies, gas from the virgin Outer Continental Shelf areas. Each of these gases may have its own marginal cost curve, but, for most, these are now unfortunately notional, and much further development is required to develop useful answers.

Finally, there is the problem of availability, both in volume and in time pattern. If a given gas source is physically in quite limited supply, its marginal cost is not too significant. Moreover, as with SNG, its marginal cost (forgetting load factor considerations) may be higher than, say the cost of gas from the Outer Continental Shelf, but SNG has a time value, in a temporarily severe shortage period, if the shelf gas is five to ten years away.

The Need for Demand/Supply Curves

Another element to consider is the likely demand curve for gas, relative to the availability and cost of the various sources. It may be likely that at no probable marginal cost-based price (given the cost of competitive energy sources) will demand shrink to supply in the next five to ten years because of gas availability limitations--a not too fanciful assumption. There we have one set of circumstances. Only if there is determined to be a large new source of gas (for example, the Western tight sands),

available only at, say, \$6.00 per Mcf--and, as we may assume, the market does not demand gas at such a price--do we have the classical example where its marginal cost would give a valuable answer as to appropriate action (don't develop the supply!).

It can be seen that much work remains to be done in constructing both supply and demand curves which would be useful in marginal cost applications for gas. As an interim measure in the search for a supportable, easily determinable and representative cost level of a pipeline's supply, one could take the national area rate level of \$1.42, plus the one-cent escalations, recently authorized by the Commission in its Opinion No. 770.

While this cost level does not meet the theoretical economic definition of marginal cost and does not approach the cost extremes of nontraditional supplies, such as SNG, imported gas, coal gasification, etc., it nevertheless is representative of the cost of a pipeline's major supply source--particularly as the lower-priced gas supply contracts run out.

At the other extreme, when adequate information becomes available, one could take the cost (at equal load factors) of the highest-cost marginal supply with potential volumes large enough to be significant in the pipeline's planning time frame. There is also room for Commission

judgment between these two extremes, as it may be applied at times in the light of demand and supply perspectives.

Action. Not Perfection, Is Needed Now

This we know: granted the acceptance of the pricing goal here suggested, progress is badly needed now, and we need not wait for the theoretically perfect solution before taking the first steps. One practical, interim technique is here suggested--far from the theoretically perfect solution, but still incorporating the marginalist thesis. This is to consider the package (on a composite basis) of incremental supplies which are to be attached during the pipeline's planning time period, say, five to ten years.

Such a computation has two virtues: data are available from planning documents; the time period is long enough to include many supplements but short enough to be useful for regulatory purposes. Here the probabilities of the various potential "candidates" for the marginal supply can be recognized in weighting their various costs in the total package on the basis of these probabilities.

This is not the place to define exactly how this cost should be determined but, with the concept of the package, it is a relatively broad band of prices which, for illustrative purposes, could be considered in the general

vicinity of \$1.50 to \$2.00 per Mcf (in 1976 dollars)¹¹ for natural gas. It would extend upward for supplemental supplies, with a composite somewhat above \$2.00, depending on how far *(how far?)* one looks and to what extent one relies on supplements.

Pipeline Costs as a "Free" Good

One further note as to the pipeline's marginal cost: few, if any, pipelines are expanding and indeed appear to have established as their objective merely the "keeping of the lines full." Further, since, if there is any expansion at all it will probably be via the relatively low-cost addition of compression (or minor looping), one may consider the marginal cost of transportation as close to zero. To the economist, sunk capacity cost is not relevant to rate making as an economic matter, although notions of equity combine with the Constitution to justify its consideration in setting revenue requirements. The pipeline (and distribution) facilities are there, often partly idle. They are what an economist would call a "free good"; little price incentive is needed to use them.

There are, of course, marginal gathering costs. As more reliance is placed on storage, marginal storage costs would be added to make the total marginal cost of the pipeline somewhat higher than the marginal supply price, as

11. If this sounds low, given recent reported intrastate contracts, the reader should keep in mind the oil industry's contention that intrastate supply and demand seem to be in balance at current prices.

the Commission may determine it. This total marginal cost would be the standard adopted for the pricing formula to be next discussed and for the pricing of direct pipeline sales to industry.

Revenue Gap: A Problem Needing Consideration

It will be seen from the above that a properly determined marginal cost will be well below some of the more astronomical figures which have been quoted (in important part because of the fact that the fixed cost of the transmission system is not marginal). Still, the end result will be a cost rather substantially higher than the present approximately \$1.25 per Mcf average delivered cost of pipeline gas. What then should be done about the revenue gap which would be created were the pipeline rates to be fixed at marginal cost and yet were the Commission's concept of a fair rate of return on rate base to prevail?

Three things may be said about this gap. In the first place, the Commission will need to consider, on the traditional costing side, whether all of its previous assumptions are still reasonable. There is a movement upward, for instance, justified by the nature of gas supply, in depreciation rates. Furthermore, a higher rate of return, justified by the increasing risk characteristics of the transmission companies, may call for recognition.¹² Accounting

12. Cf. FPC Opinion No. 762 in re Natural Gas Pipe Line Company of America, in RP74-96, for its most recent dicta on this point.

changes are under consideration, which would increase current (in contrast to long-run) revenue requirements.

Another element might be an exploratory, or R and D, surcharge devoted to enhancing gas supply, appropriate because marginal cost is the cost of replacing gas being depleted. If there remains a substantial gap between cost and current revenue, here would be an ideal occasion to accumulate capital to be devoted to expanded exploratory activity, to improve technology in extraction methods or to provide supplemental capital for high capital cost projects. Thus, traditionally determined cost may also be on the way up and the gap between average revenue and marginal cost may be narrowing.¹³

However, there may still be a gap. Two¹⁴ alternatives were offered in the theoretical discussion advanced above: (1) the use of relative elasticities as a criterion and (2) marginal cost rates accompanied by an economically neutral "customer dividend." The latter course has to be the preferred one here. Determining elasticities (as between different distributor customers) is particularly difficult in respect to pipelines, which act in the role of middlemen, registering customers' demands on the initial supplier.

13. Theoretically, it could be eliminated by the sort of "windfall" tax alluded to in Footnote 8.

14. This is not to ignore the FPC's Office of Economics' recent proposal, but its applicability in the face of shrinking pipeline throughput may be difficult.

We cannot even completely rely on a composite of the elasticities of the distributor's customers as an index, difficult enough by itself to determine. The distributors have other supply alternatives which will vary as between different companies.

Consequently, the second alternative for gap bridging (described previously) is here preferred. This suggests basing the pipeline's rates on a reasonably (and judgmentally) determined long-run marginal cost and then "paying back," here to the distributor body, the difference between the revenues so measured and the "just and reasonable" revenue target. This must be done, as above noted, in an economically neutral fashion which will not affect the customers' usage.

Use of a "Demand Charge" Credit

It is suggested that the most equitable criterion may be the size of the customers' contract demands, for it was on the basis of these contracts that the pipelines were built up. Thus, the credit would be in the nature of a "demand charge credit," although a similar equitable standard might be devised. The only rule is that it not be pro rata to current and anticipated usage; otherwise the marginal cost pricing goal would be frustrated.

The purchaser then will always know, if this alternative is adopted, the (marginal) cost of the additional gas

which he is buying or, conversely, the saving he is creating for the pipeline by foregoing the purchase,¹⁵ and may base his usage decisions thereon.

An Inverse Elasticity Approach

The other route for "bridging the gap"--making use of inverse elasticity considerations, despite their complications--may be worthy of further thought, though more difficult to apply. As between distributors, it is hard to consider one as more or less price elastic than another. However, the mix of the distributor's sales could provide some clue if it were determined, for example, that the elasticity rank followed priority rank in inverse order (the low-priority group, being more easily convertible--less "captive"--having the highest price elasticity).

It would be possible to devise a pricing scheme which priced all gas at the found marginal cost but with a credit depending in size on the proportion of high priority to total sales by the distributor. This bears some similarity to the FPC's proposal in RM75-19¹⁶ (hardly

15. It is recognized that some "curtailment adjustment" formula may need to be applied periodically if the supply outlook ahead is too chaotic.

16. FPC Notice of Proposed Rulemaking issued in Docket No. RM75-19 (End-Use Rate Schedules) on February 20, 1975. This proposal would require major interstate natural gas pipelines to file rate schedules for sales for resale in interstate commerce based upon the end use of the gas sold.

received with enthusiasm) and to the Office of Economics'
suggestion. However, because of its complications, this
alternative is considered a distinctly second choice.

Setting Rates on a Seasonal
(Average Cost-Supported) Basis

Finally, there is a potential halfway measure which would utilize summer sales as the balancing factor to bring total revenue within the approved limits, on the theory that gas demand is most affected by peak-period, winter prices. A winter rate (October through March?), when gas service is at its optimum value, would be set at the predetermined marginal cost level. A summer rate for the other six months would be set at a somewhat lower level, which would encourage the purchase of gas to be stored for later withdrawal to provide high-priority winter service at the high winter rate. (Presumably, some constraint would have to be exercised in respect to interruptible sales during this period.)

Using the proper design techniques, the rates could be structured in such a manner that annual revenue would cover all pipeline costs, thus including the cost of sunk capacity referred to above, as well as the actual average cost of the pipeline's gas purchases, and so being "cost supported," in the current accounting concept of cost. An obvious advantage of the "cost-supported" rate structure would be to eliminate the problem of revenues in excess of approved revenue requirements. Further, the higher winter

rate, though "cost supported," would be of a magnitude that would promote conservation by the end user, encourage high-priority use and even provide the cost incentive to seek alternate fuel sources.

It has been suggested that marginal cost pricing at the wholesale level would not be effective unless similarly applied at the retail level. However, this ignores the lessons the former would teach (1) the distributor, in shaping his supply program and in making his rates, and (2) the state regulatory agency, in considering the appropriateness of retail rates. With 48 affected states and only one FPC, the latter has to take the lead as a practical matter if a unified and consistent national policy is to be achieved.

Difficulties in Determining Distributors' Marginal Costs

As for marginal cost pricing by distributors, the same general principles, described above, are of course applicable. Here, knowledge of the distribution area's demand curve is particularly useful and the distributor's supply alternatives are usually more limited. Nevertheless, it may still be difficult to determine the marginal cost, for use in a rate case, for many of the reasons discussed in respect to pipeline pricing. Consequently, the compromise solution there offered of pricing a "package" has similar applicability here.

First, let us take the series of costs entering into what might be called the plant gate, or supply costs, of the distributor. These would be the complex of costs of the various new supply elements making up the increment to supply over the planning period being studied, say, five to ten years. It is important here to "pierce the corporate veil" between the pipeline and its customers and to consider the pipeline's marginal cost, rather than the net amount it may be charging the distributor-customer. This is clearly superior to an attempt to determine the future average cost of gas purchased from the pipelines because of the substantial element in those costs of "rolled-in" old gas supplies. The pipeline's marginal cost is the cost to society of those new supplies.

Were the FPC to adopt the type of marginal cost pricing suggested above, the FPC-found pipeline marginal cost would then be the most important element in the distributor's total marginal cost of supply. Included also, however, would be the supplements which the distributor itself has lined up to come on the line during this time period. The marginal supply costs would be the composite of the total new supply.

Storage Costs

The question of how to treat storage costs is another matter, depending heavily on the specific circumstances in the proceeding in which rates are being fixed.

Some storage costs, of course, are "rolled in" to the pipeline charges, but other storage costs are discrete elements, separately treated in the gas supply costs which the distributor must bear.

Since there will undoubtedly be a greater dependence on storage in the future, it is important to determine properly the cost of incremental storage capacity. This, in turn, depends on the pipeline's (or distributor's) opportunities. Unfortunately, the subject does not lend itself to a general prescription. One clear rule, in the pricing suggestions which are to follow: "winter" gas prices must bear this added increment of storage cost.

While considering the added winter increment, one must also consider the potential cost to be charged winter-time customers for purchasing large volumes of a 100% load factor, year-round supply. Because of the nature of the purchase contract,¹⁷ there may well be gas which has to be disposed of, or expensively stored, during the slack season at a price dictated by the cost of other competing fuels. Three-dollar gas cannot (yet) readily be sold interruptibly for that price. Again, this is a matter which must be determined on the basis of the facts of the service territory being considered.

17. E.g., LNG contracts, Alaskan pipeline gas contracts, gas from coal, etc., with heavy fixed charge components.

Various Other Distributor
Costs Involved

Finally, there are the other costs which the distributor must bear in getting the gas to the consumer's meter. These are the costs of distribution, customer service, meter reading, billing, accounting, etc. By and large, with the exception of costs of mains to serve new customers (a large part of which could well be borne by a one-time charge or a tighter line extension rule), there will be little expense required to expand the capacity of distribution systems.¹⁸ Thus, the marginal cost of distribution will be quite low. Indeed, even many of the "variable" costs would be largely in the customer category and would be included in a customer charge set to recover such costs as needed, rather than recovered in a per Mcf charge.

Differences Between High-Load Factor
and Temperature-Sensitive Loads

The implication of this analysis is that the principal differential between high-load factor use (as in the case of industrial customers) and temperature-sensitive loads (as is primarily the case with residential customers) is in the nature of the additional storage and other winter-time charges, which a careful marginal cost computation would find should be assessed against predominantly winter usage.

18. This leaves open the question of certain capital costs related to escalating safety requirements, urban renewal and the like. These may be marginal--but probably not marginal in terms of the quantity used.

It is unlikely that these charges will be higher than the present differential between industrial and residential customers. Illustratively, the formula might be: residential price = marginal supply cost (say, \$2.25 Mcf) + marginal distribution cost (say, 10¢) + charge for excess winter use (say, 40¢). A customer charge would be in addition (say, \$5 per customer).

Excess Revenue Problems With Distributors

The problem of excess revenue, discussed in respect to pipeline charges to distributors, may of course also be present in distributors' charges to their customers. The word may is used because the element of present "fixed" cost--or costs not variable with volume--is substantially higher in the case of the customers of the distributor than in the other instance. If we think of per Mcf marginal supply costs to the consumer, as determined above, in the \$2.75 area (exclusive of "customer costs"), we are, in many sections of the country, in the vicinity of the level of per Mcf prices currently being charged (when recognition is taken of the size of the current fuel adjustment clauses). It is much less likely, therefore, that some of the more novel suggestions made in respect to pipeline pricing would be required in the case of distributors' rates to their customers. In the East, it is thus entirely possible that an appropriately fixed customer charge may be all that is needed to effect a balance between marginal costs and costs as traditionally

determined (but note a prior comment on updating these traditional determinations). This may not be the case, especially in areas closer to the producing fields, and some discount must be offered below marginal cost. - One has the teachings of the economists, as above stated, to guide how this should be done, as well as recourse to a phasing-in process. The earlier discussion as to modification of pipeline prices may also be applicable here, particularly when considering industrial rates.

One further word with respect to elasticity--it may be extremely difficult, because of data problems, to compute elasticities in the traditional sense. However, we have at hand a possible interim substitute for this computation in the concept of "substitutability," which obviously is an important component of elasticity. A determination of consumer cost of converting to another fuel, both in capital cost and potential higher fuel cost (all in relation to his current annual bill for gas), is a useful measure of the degree of "captivity" of the customer--his inelasticity. If conversion would cost him, say, five times his annual bill, as may be the case with residential customers (in contrast to many industrial uses where the multiple would be considerably lower), this would be a clear indication of where it is less necessary to adhere so closely to the marginal costs as found.

Inherent Elasticity of Interruptible Rates

A word as to interruptible rates--in general, they should not be below marginal cost since, almost by definition, there is a high degree of elasticity here. The practical exception would be where it is necessary to dispose of gas in the summer (perhaps while storage plans are being developed) because of take-or-pay-for considerations. Here, to avoid an "unused gas penalty," it may be necessary to shade a marginally determined price, as competition requires. State commissions may want to "deregulate" such rates--since competition should make regulation unnecessary--attributing the revenue from such sales to be equal to marginal supply cost, except in those circumstances where it can be shown that a necessary deficit has been incurred due to the take-or-pay-for situation described above.

Use of Fuel Adjustment Clauses

Nothing has been said to this point about fuel adjustment clauses. If they are necessary as revenue stabilization features between rate cases, they can be continued as at present.¹⁹ With the need to "work into" marginal cost pricing in steps, to be next discussed, it is unlikely that the per Mcf charges would exceed marginal cost, particularly if these charges are "rolled into" the

19. Again assuming the existence of a "revenue gap." But such adjustments should never be added to a price based exactly on marginal cost as that would constitute double counting.

revenue requirements determination in each rate case, a necessary concomitant to the rate suggestions herein offered.

A Clear Need for Phasing in Changes

A word about continuity--some of the above suggestions may--and that word is italicized--indicate fairly abrupt changes in existing pricing practice. Where this is so, it should go without saying that the changes may have to be made in phases in order to satisfy concepts of equity. This, again, is a matter as to which no exact formula may be offered. The goal has to be to get to marginal cost prices as soon as is feasible and, if there is to be a delay due to phasing, to let the customers know where prices are going.

Conclusion

Where does all this leave us? This section seeks to show that there are ways to convert present pricing mechanisms into marginal cost-based pricing techniques within the framework of the regulatory system now applicable to gas companies.

It needs to be kept in mind that this framework has only two overriding criteria: first, that equity be preserved between the stockholders and the consumers as a body and, second, as between consumers, that rates not be unduly preferential. The word unduly is italicized because courts have many times said this can be interpreted in the light of prevailing conditions (including, we would contend, economic efficiency).

Having shown that an economic pricing alternative (to rationing) is feasible, strong arguments can be offered as to the desirability of "getting on with the job" and keeping to a minimum the scope to be given to rationing. It may well be that in the near term the supply situation will be such that rates necessarily set at less than marginal cost (to meet the revenue constraint) will not bring demand and supply into balance. It may even be that rates set at marginal cost might not do the job for several years because of the lag caused by the necessity of replacing fuel-burning equipment.

There is nothing infeasible or inconsistent in recognizing the necessity of these dual restraints in an interim period, for some allocation may clearly be necessary. But the notion that some central agency, Federal or state, can set "priorities" and allocate supplies efficiently is belied by all experience. If prices are allowed to do the job and if the prices are incorrectly set, the worst that will happen is that some customers will overpay and others underpay. But if "priorities" are incorrectly determined, the wronged consumer gets no gas; the error is total.

Nor should we pretend that orders forbidding new attachments avoid rationing. They are rationing, and rationing of the most discriminatory sort. Existing customers are "grandfathered" into a privileged status

at the expense of potential customers even if the latter place a higher value on the gas.

Transition--and Decision

What will be needed is a transition period (five years?) during which this readjustment will take place-- and during this time, rationing by fiat will have to continue-- although price may progressively be of help (viz., utility plant decisions in Texas to build coal plants).

What is now required is agreement, first within the industry, as to the direction in which it wants to go and, second, between government and industry that the selected course is the right one. Then, the myriad of decisions which have to be made as time goes on will be made to facilitate reaching the agreed-upon goal, not to frustrate it.

ILLINOIS POWER COMPANY

500 SOUTH 27TH STREET, DECATUR, ILLINOIS 62525

July 2, 1979

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street, N.W.
Washington, D.C. 20461

792221

Economic Regulatory Administration
Docket No. ERA-R-79-22

Attached for filing are ten (10) copies of the Comments of Illinois Power Company with respect to the above captioned docket dealing with the study of natural gas utility rate designs.

An additional copy of this filing is included which we request be date stamped and returned in the enclosed postage prepaid and self-addressed envelope as verification of filing with your office.

Sincerely yours,

ILLINOIS POWER COMPANY

S. L. Swarthout
Supervisor - Federal
Regulatory Matters

SLS:jeh
Attachments

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

Study Concerning)
Natural Gas Utility)
Rate Design)
Docket No. ERA R-79-22

COMMENTS OF ILLINOIS POWER COMPANY

Illinois Power Company ("Illinois Power" or "Company") respectfully submits the following comments in response to the notice dated April 30, 1979, by the Economic Regulatory Administration ("ERA") in the captioned docket. The notice states that the Department of Energy is required under Section 306 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") to study gas utility rate design, and in so doing provide opportunity for consultation and comment by the Federal Energy Regulatory Commission, State regulatory commissions, gas utilities, and gas consumers.

I

The exact legal name of the Company is ILLINOIS POWER COMPANY. It is a corporation duly created, organized and existing under the laws of the State of Illinois, having its general business office at 500 South 27th Street, Decatur, Illinois. Communications and correspondence concerning this proceeding should be addressed to:

Mr. M. P. Mladiner
Mr. E. A. Deardorff
Illinois Power Company
500 South 27th Street
Decatur, Illinois 62525

II

Illinois Power is a gas and electric utility company operating in substantial areas in the State of Illinois, and, under the Illinois Public Utilities Act, (Chapter 111 2/3, Section 1 et seq. of the Illinois Revised Statutes) is subject to the jurisdiction of the Illinois Commerce Commission. Illinois Power is also subject to regulation under the Federal Power Act. Under Section 1(c) of the Natural Gas Act, the Company has been duly declared exempt from the provisions of that Act and the Rules and Regulations of the Federal Power Commission (now the Federal Energy Regulatory Commission) on February 3, 1958, in Docket No. G-13934.

III

Illinois Power Company's position with respect to the proposed gas rate design study is that ultimate findings should be as consistent as possible with Section 111 of PURPA concerning electric rate design. Specifically, this should provide for (1) gas rates closely based on the actual costs incurred to supply such service and (2) administration of all federal recommendations by state regulatory commissions. The Company wishes to address these matters as follows:

IV

Illinois Power Company feels it is crucial to the future well-being of the natural gas industry that rates applicable to all end-use consumers reflect to the extent practicable the actual customer, demand, and commodity costs associated with each class of service. Gas rates have historically been comprised of very low customer charge or minimum bill provisions with declining block commodity charges utilized to recover the necessary return on invested capital. This structure is no longer adequate. No utility wants to find itself in a position that requires petitioning a regulatory commission for a rate increase because the essential return ordinarily recovered in commodity charges has been eroded due to consumer conservation. If companies such as ours are to maintain financial stability while at the same time providing proper pricing signals to customers, our gas rates must contain facilities charges permitting full recovery of all embedded customer and class demand costs and commodity charges nearly uniform across rate classes set at a level greater than the average cost of gas and less than the value of alternative service and augmented by purchased gas adjustment clauses. Consistent with a need to cover revenue requirements and minimize abrupt changes in total prices to customers, the commodity charges should approach the marginal cost of gas as the prices of alternative fuels are increased. Seasonal rates, when justified by variation in costs, would not be inconsistent with this design.

We feel such a rate structure, when combined with appropriately designed interruptible rates, will permit utilities to provide customers with economical service for the foreseeable future, regain essential financial integrity, and promote the necessary interests of conservation. Illinois Power Company recommends that the proposed gas rate design study conduct a thorough analysis of such rates, applying stability of cost recovery as a principal evaluative criterion.

V

Illinois Power Company further recommends that any and all gas rate design standards ultimately find application through the state regulatory commissions now charged with administering such comparable electric standards or existing gas rate structures. For reasons identical to those presented for the Section 111 standards, state

commissions should be permitted to determine which gas standards are appropriate for utilities within their jurisdiction, based on local service characteristics and local regulatory needs and requirements.

Respectfully submitted,

ILLINOIS POWER COMPANY

Larry D. Haab
Vice President

STATE OF ILLINOIS)
)
COUNTY OF MACON)

I, Larry D. Haab, being duly sworn, depose and say that I am Vice President for Illinois Power Company, that I am authorized to file the foregoing Comments, that I have read the Comments and know the contents thereof, and that the same are true to the best of my knowledge and belief.

Larry D. Haab
Vice President

Subscribed and sworn to
before me, a Notary Public
this 2nd day of July,
1979.

Notary Public

(SEAL)

UNITED STATES OF AMERICA
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

792222

In the Matter of:	)	
	)	
Gas Utility Rate Design Study:	)	
Responsibilities Under Public	)	Docket No. ERA-R-79-22
Utility Regulatory Policies	)	
Act Of 1978	)	

PRELIMINARY COMMENTS OF THE
PROCESS GAS CONSUMERS GROUP
AND THE GEORGIA INDUSTRIAL GAS GROUP

Pursuant to the Economic Regulatory Administration's ("ERA's") Notice Of Inquiry, issued April 30, 1979, the Process Gas Consumers Group ("PGC") and the Georgia Industrial Gas Group ("GIG") hereby respectfully submit their preliminary comments on the Department of Energy's ("DOE's") duties, responsibilities, and authorities under Title III, Section 306 of the Public Utility Regulatory Policies Act of 1978 ("PURPA").

I. INTRODUCTION

PGC is an association organized to promote the development and adoption of coordinated, rational, and consistent federal and state policies which will assure an adequate and reliable supply of natural and manufactured gas at just and reasonable cost-based rates for industrial gas uses which cannot technically or economically be converted to alternative fuels. The members of PGC participating in this proceeding, all of whom are high-priority process gas users, include: American Can Company, Armco, Inc., Cone Mills Corporation, General Motors Corporation, Libbey-Owens-Ford Company, Owens-Corning Fiberglas Corporation, and United States Steel Corporation.

Joining with PGC for the specific purpose of participating in this proceeding are the following members of the Georgia Industrial Gas Group: American Industrial Clay Company of Sandersville, Anglo-American Clays Corporation, Chemical Products Corporation, Freeport Kaolin Company, Georgia Kaolin Company, Griffin Pipe Products Company, and Thiele Kaolin Company. These companies all operate industrial facilities which consume natural gas in the State of Georgia. (General Motors, a member of PGC, is also a member of GIG.)

II. GENERAL COMMENTS

PGC and GIG ("the Groups") infer from the Notice of Inquiry in this docket that this phase of the proceeding is intended to be preliminary only -- establishing the parameters of the gas rate design study, but not yet focusing substantively on specific rate designs, related issues, and "evaluative criteria." The Groups intend to participate fully as this proceeding progresses, submitting specific comments on individual rate design proposals. The Groups will be especially interested in commenting on incremental pricing and end user rate schedules (to the extent not already pre-empted by the Natural Gas Policy Act of 1978), as well as proposals involving marginal cost pricing, demand/commodity cost allocation, declining block rates, and end user gas consumption taxes. As Congress has recognized, rate design proposals embodying components such as these have recently become the subject of considerable popular interest, and they deserve rigorous critical examination and evaluation. The Groups hope to be of constructive assistance to ERA in carrying out the Congressional mandate to study such proposals, and we intend to take advantage of the promised "additional opportunities for public comment and consultation" to that end.

For the present time, however, the Groups would restrict their comments to the additional "evaluative criterion" identified by ERA in its Notice -- equitable rates to gas consumers. ERA apparently recognizes, as did Congress, that the standard of equitable rates is one against which any proposed rate design or concept must be critically analyzed. As important as the goals of energy conservation and utility efficiency are, the goal of affording equitable rates to all natural gas consumers is of no less importance.

The achievement of equitable rates for all gas consumers is consistent with the traditional function of utility ratemaking to (1) determine a utility's revenue requirement -- its total average costs of service, including a reasonable return on its rate base -- and (2) match these costs to the consumers who actually impose them upon the utility system. Since utility revenue requirements are thus assessed on total average costs, utility rate structures have traditionally been designed on the basis of average cost principles as well. Average cost rate structures, properly devised, seek to allocate the utility's revenue requirement so that the prices charged to consumers for services reflect only the actual costs the utility has incurred in providing them with those

services. */ Such a self-regulating approach eliminates subsidization among customers by insuring that all customers pay their own way. In so doing, a utility recovers its full costs -- no more and no less. That is, utility revenues stay in balance with costs actually incurred without the need to resort to post hoc and typically-discriminatory rate/revenue adjustments.

Unfortunately, the focus of many so-called "rate reforms" in the recent past has not been to insure equitable rates to all consumers, but rather to insure below-cost rates to some consumers at the expense of (and via subsidization by) other consumers. It is this potential problem with which the Groups are likely to be most concerned in the course of this proceeding. In short, we urge ERA to continue to bear in mind in the course of its study the necessity of focusing on the basic classical utility obligation of natural gas suppliers to provide service to all classes of customers on a non-discriminatory basis. Some of the rate design proposals identified in Section 306 of PURPA, as well as others which may also be considered by ERA, could well seriously undermine this fundamental concept of service which has been the foundation of utility operations since their inception. In the face of the potential erosion of that concept, the Groups strongly affirm their support for, and urge ERA to adhere rigorously to, the traditional ratemaking wisdom that utility rates should be based upon actual costs and should attempt to match costs, to the greatest practicable extent, with the consumers who are responsible for imposing them upon a utility system.

It may be useful at this preliminary stage of this proceeding to reflect upon the manner and extent to which some of the currently-popular "rate reform" proposals challenge sound traditional ratemaking goals. Some such proposals begin with the premise that the relevant costs for fixing rates are not the utility's average costs -- upon which its revenue requirements are determined -- but its marginal or incremental costs, as variously defined. Other proposals, such as some versions of lifeline rates, reject outright the traditional notion that rates should be cost-based for all con-

*/ Ideally, utility rates should also be structured so as to have each consumer class pay a rate which includes a rate of return component as close as reasonably possible to 100% of the system average rate of return; stated differently, the index of return for each consumer class should be 1.0.

sumers. These "reforms" illustrate a change in perspective, or at least in emphasis, as to what a rate is, what it should accomplish, and what the overall scope of the ratemaking process is or should be. */ Although most utility commissions are subject to statutory and sometimes state constitutional mandates to set "just and reasonable" rates, most reformers look upon rates as more than merely the just and reasonable quid pro quo for a utility's services; they are instead a social or economic tool which may, for example, promote conservation of gas, allocate decreasing supplies among competing consumers, lower peak demand, or provide relief for low income consumers. The result of this view is to broaden considerably the overall scope of the ratemaking process.

Although most reform proposals purport to be cost-based, their implementation usually results in wide deviations from whatever cost standard is employed. To the extent that rates significantly depart from costs as the touchstone by which they are set, the ratemaking process becomes even more politicized and, indeed, akin to taxation. As a result, rates paid by some consumers will be greater than the cost to the utility of providing service to them, while rates paid by other consumers will be substantially less than the utility's cost of providing that service. The determination of who subsidizes whom will in turn depend, to a large extent, on the political judgment of regulators, as well as on the particular policy goals certain pricing techniques purport to encourage and regulators seek to advance. Such reforms may thus lead to significant income redistribution among and within customer classes and may provide regulatory commissioners with virtually untrammelled discretion.

As will no doubt develop during the course of this proceeding, especially as specific rate design proposals are closely examined, many of the currently-popular "rate reforms" when actually applied in practice, result in emasculation of the sometimes sound economic theories on which they are based, in wide deviations from cost-based rates, and in economic and perhaps legal discrimination against some consumers. Moreover, these proposals for the most part also fail to achieve

*/ This view that current rate reform proposals would considerably broaden utility ratemaking and transform it into a form of taxation is developed in detail in Aman & Howard, "Natural Gas and Electric Utility Rate Reform: Taxation Through Rate-making?" 28 Hastings L. J. 1085 (May 1977), from which article these comments are largely drawn.

the broad social policy goals which they are intended to advance. In short, the traditional ratemaking goal of matching consumers' rates with the costs incurred by the utility in serving them is better served by rates based on average costs, while the broader social objectives are better served through such rates in conjunction with legislative and administrative programs which are narrowly drawn to advance such broad social objectives more directly and effectively. */

Using a utility's actual cost of service as a basis for setting rates enables a reasonably objective cost standard to be employed. In the absence of such a standard, the power to set rates is, in effect, transformed into the power to tax. Regulatory commissions usually are not vested with, nor accustomed to, an explicit power to tax. Furthermore, they are generally subject to judicial review under only the most deferential of standards. Due to the popular reaction against rising utility rates, many commissions are especially vulnerable to political pressure. Thus, there is a great temptation to embrace certain rate design reforms simply because they have a revenue impact which is politically acceptable to a majority of the regulators' constituents, without subjecting such reforms to sufficiently rigorous examination.

Consequently, because of the potential violence which may be done to sound utility ratemaking goals and principles by some gas utility rate design proposals, the Groups welcome the opportunity afforded by Section 306 of PURPA to subject to careful and rigorous examination each of the rate design proposals identified in ERA's Notice. We will urge throughout this proceeding that natural gas rates be designed so as to be objective, definable, predictable, and equitable to all gas consumers. To that end, we urge at minimum that each rate design proposal examined in ERA's study be approached in the following manner:

*/ For example, lifeline rates are intended to assist low income consumers by subsidizing their usage of a minimum quantity of gas. Such rates, however, fail to aid all low income users, and it is likely, under such a theory, that some low income users will be forced to subsidize some higher income users. The social welfare goal of subsidizing subsistence usage of energy by lower income consumers might be achieved more directly and more effectively through development of, for example, an energy stamp, income support, or other type of direct welfare program which would not involve distortion of utility ratemaking.

(1) the underlying assumptions and intended goals of each rate design proposal must be explicitly identified;

(2) the validity of each of these underlying assumptions must be supported by substantial credible evidence and tested; and

(3) each rate design proposal must be evaluated in terms of its realistic capability to achieve effectively its intended goals.

III. CONCLUSION

The Process Gas Consumers Group and the Georgia Industrial Gas Group appreciate this opportunity to submit their preliminary comments and recommendations with respect to the general approach which ERA should pursue in fulfilling its statutory duties under Section 306 of PURPA. We look forward to submitting more specific and substantive comments on gas utility rate design proposals at the appropriate time.

Respectfully submitted,

Edward J. Grenier, Jr.
Glen S. Howard

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Attorneys for
The Process Gas Consumers Group
and the Georgia Industrial Gas Group

July 9, 1979

NFA National Food Processors Association
1133 Twentieth Street N.W., Washington, D.C. 20036
Telephone 202/331-5900

792223

July 2, 1979

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street, N. W.
Washington, D. C. 20461

Docket No. ERA-R-79-22/Gas Utility Rate Design Study

The National Food Processors Association is a non-profit trade association whose member firms account for 90 percent of the production of United States canned foods. Canning converts perishable foods into nonperishable form. Products of the U. S. canning industry include canned fruits, vegetables, juices, meats, poultry, fish and shellfish, baby foods, soups, and many formulated food products and food specialties.

The National Food Processors has a unique interest in the Gas Utility Rate Design Study and particularly in certain of the rate designs and issues on which the Economic Regulatory Administration has invited comments, as follows:

1. Incremental pricing. It is expected that all of the natural gas consumed by food processors--in agricultural production, food production, and food quality maintenance--will be exempted from incremental pricing pursuant to Section 206 of the NGPA, and that this exemption will be within the jurisdiction of the Federal Energy Regulatory Commission. In order to effectuate that exemption it will be necessary to incorporate the exemption for "agricultural uses" in the rate structures of each regulatory jurisdiction and each natural gas distribution company. The NFPA recommends that ERA make appropriate recommendations toward that end.

Please see also "Related issues" in this submission

* * * * *

3. Seasonal rate differentials. Food canning is one link in the production and processing of food for which DOE has established the "agricultural production" priority for allocated petroleum products based on the farmers' and processors' requirements for energy on hand as needed to produce and process perishable foods into nonperishable, storable form. As part of the agricultural community, canners purchase most of their vegetables from growers under exclusive contracts.

Although canners contract for acreage on the basis of prior years' crop yields, neither growers nor canners are able to accurately predict the volume of product that will be delivered each season for processing. At the time of harvest, fruits and vegetables may be delivered to canning plants almost around the clock. During a brief period generally lasting no more than four to six weeks in each locality, canners convert into nonperishable form the foods which will be marketed over the coming year.

Canners have no choice during the harvest of perishable fruits and vegetables but to consume energy as needed, as the harvest comes in, to process perishable foods into nonperishable form. Extended periods of shutdown are unacceptable because of food quality deterioration and risk of outright spoilage. The NFPA submits that it would be inappropriate to impose a penalty for seasonal or other peakload use of energy on those, such as producers and processors of perishable foods, who are unable to adjust energy consumption to avoid the penalty. The NFPA submits that penalty rate differentials would be inappropriate and would not be cost effective where agricultural producers and food processors are

unable to adjust their energy consumption to avoid the penalty, and that ERA should make appropriate recommendations which take account of the special considerations that apply to agricultural users in this respect.

* * * * *

7. Interruptible service. For the same reasons as those given above, agricultural producers and food canners are unable to accept energy interruptions during the harvest and processing of perishable foods. The NFPA submits that ERA recommendations with respect to "interruptible service" should take account that energy interruptions are unacceptable for producers and processors of perishable foods.

* * * * *

Related issues. There is at least one other regulated issue which the ERA should address, that being the effectuation of Federal energy policies in state and local regulation notwithstanding the limited scope of direct federal jurisdiction.

Although Section 401 of the NGPA is designed to protect "essential agricultural uses" from natural gas curtailment, the Congressional intent in establishing this priority may be frustrated by the failure of either the FERC or the ERA, or both, to condition deliveries of interstate gas to local distributors on the requirement that such priority gas be passed on to "essential agricultural users" who would otherwise obtain such priority gas if they were only served by interstate pipelines rather than by local distributors. Indeed, the Wisconsin Public Service Commission has already signaled its intention to ignore the priority for "essential agricultural uses" and to divert agricultural priority gas to other end uses. The

NFPA submits that the ERA should make appropriate recommendations and take appropriate action to ensure that natural gas priorities in the States will be in accord with Federal energy policy.

Respectfully submitted,

Leonard K. Lobred, Director
Industry and Trade Regulations

STATE OF NEW YORK DEPARTMENT OF PUBLIC SERVICE

THE GOVERNOR NELSON A. ROCKEFELLER
EMPIRE STATE PLAZA ALBANY 12223

PUBLIC SERVICE COMMISSION

CHARLES A. ZIELINSKI
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792224

PETER H. SCHIFF
General Counsel

SAMUEL F. MADISON
Secretary

June 26, 1979

Department of Energy
Office of Public Hearing
Management
Room 2313
2000 M Street, N.W.
Washington, D. C. 20461

Re: Docket ERA-79-22.

Gentlemen:

The New York Public Service Commission is not recommending that any additional areas of gas rate design be addressed in the above-referenced Docket. With respect to the evaluative criteria, however, we recommend that the effects of the wellhead and industrial incremental pricing provisions of the Natural Gas Policy Act of 1978 on elasticity of gas demand be taken into account.

We wish to participate with ERA and other interested parties during the preparation of, and upon the completion of, the studies you plan to undertake. We would, therefore, appreciate being placed on the service list in this proceeding.

Sincerely yours,

Peter H. Schiff

PETER H. SCHIFF
General Counsel

Department of Energy
Office of Public Hearing Management
Room 2313
Docket ERA-R-79-22
2000 M Street, NW
Washington, D.C. 20461

792225

Re: Docket ERA-R-79-22
Notice of Inquiry, Gas Utility Rate Design Study;
Responsibilities under Public Utility Regulatory
Policies Act of 1978.

Gentlemen:

Wisconsin Gas Company offers the following comments on the Notice of Inquiry on the Gas Utility Rate Design Study to be conducted by the Economic Regulatory Administration (ERA) as required under the Public Utility Regulatory Policies Act of 1978.

Wisconsin Gas Company (Wisconsin Gas) is the largest distributor of natural gas in the State of Wisconsin, serving approximately 400,000 customers in 366 communities throughout the state with a population of approximately 1,600,000. The Company purchases all of its gas from three non-affiliated interstate pipeline companies.

Wisconsin Gas is a member of the United Distribution Companies (UDC) which is filing comments in this proceeding. Wisconsin Gas fully supports the UDC comments and offers these complementary comments to emphasize certain points discussed by UDC. These comments are organized as followed:

- I. General Comments.
- II. Rate Design and Related Issues.
- III. Additional Evaluative Criteria.
- IV. Definitions of Rates and Evaluative Criteria.
- V. Opportunities for Consultation and Comments.

1. GENERAL COMMENTS

Wisconsin Gas Company is greatly concerned about the prospect of nationally legislated rates for local gas distribution utilities. Wisconsin Gas Company strongly believes that the regulation of local utilities and their rates is (and should continue to be) the responsibility of State regulatory commissions. State and local regulatory bodies are best able to consider rate design objectives in the context of the individual character of each distributing company which has resulted from differences in supply contracts, storage and peaking gas supplies, interruptible customers, local regulations, weather conditions, types of customers, etc.

Inasmuch as the rate design study must conclude in legislative proposals, Wisconsin Gas Company recommends that the study be directed toward general rate policies which should be considered by the State regulatory commissions and implemented at the local, distributing company level only as they are determined to be "appropriate" and "consistent with otherwise applicable State law" as provided for electric service rates by Sections 111 and 113 of PURPA.

Wisconsin Gas Company believes that the correct focus of a national rate design study should be the price and contract provisions of pipeline companies and wellhead producers. Such a focus would be consistent with the objectives of PURPA since distribution utility rates are largely the consequence of the price structure and contract provisions of the pipeline tariffs under which gas is purchased. The cost of gas supply is the major element of gas consumer rates. In the case of Wisconsin Gas Company, the cost of purchased gas presently accounts for over 70% of the cost of providing gas utility service to customers. By 1985, the cost of purchased gas is expected to account for over 80% of total gas utility costs.

Inasmuch as the rate design study will attempt to evaluate the merits and implications of specific rate designs for distribution utilities, Wisconsin Gas Company believes that the study must recognize and consider the interrelationship among the various classes of customers served by a distribution utility. Altering rates for one customer class necessarily affects the rates for other customer classes since the aggregate revenue designed to be recovered from all classes must match the utility's revenue requirement. Also, different types of rates may cause customers to respond (i.e., change their gas consumption) in a way which affects the quality of service to other customers by changing the ability of the utility to manage gas demand within the peak day and annual supply constraints. Since these interrelationships can be complex and depend upon the specific character of each distribution utility, Wisconsin Gas Company recommends that the rate design study evaluate the implications of specific rate designs on a number of actual distribution utilities. Moreover, Wisconsin Gas Company recommends that ERA solicit the analysis of rate designs from distribution utilities, pipeline companies, and State regulatory commissions.

11. RATE DESIGN AND RELATED ISSUES

Wisconsin Gas Company believes the list of rate designs identified in Section 306 of PURPA and in the Notice of Inquiry by ERA is reasonably complete. However, there are several important issues related to rate design for distribution utilities which should receive attention in a rate design study. These are: pipeline pricing and tariff policies, wellhead pricing and contract provisions, and methods for allocating the component costs of providing service.

Pipeline tariffs are the link between consumers and producers. As intermediaries, pipeline tariffs communicate price and demand and supply information between producers and consumers. Consequently, pipeline tariffs have an important function in the efficient allocation of resources and in the balancing of supply and demand. Pipeline pricing tariff issues affecting rate design include: take-or-pay provisions, pricing of storage or other peak-day supply services, pricing policies for new high cost gas supply. Specifically, with regard to the pricing of new gas supplies, the study could evaluate the relative merits of alternatives such as incremental pricing, rolled-in pricing, and separate contract prices for new gas volumes based upon the production costs of the specific supplies.

Pipeline tariffs are also an important issue related to distribution utility rate design due to the need to coordinate retail (burner-tip) distribution rates and wholesale pipeline rates. Significant revenue volatility and risk of inadequate earnings for the distribution company can result if retail gas rates differ substantially from the cost of purchased gas under the pipeline commodity rate. Wisconsin Gas Company believes that pipeline tariffs and distribution rates must be developed in a consistent manner so that distribution companies are not subject to undue business risk.

Wellhead pricing and contract provisions are the starting point for natural gas rates. While wellhead pricing was addressed in the Natural Gas Policy Act, contract provisions were not. Specifically, the duration of new supply contracts may be an important aspect of wellhead pricing policy. Quick-take contracts (e.g., 5-year contracts) have a different pricing and rate design implication than long-term contracts (e.g., 20-years).

Wisconsin Gas Company strongly believes that natural gas rates should be based upon the cost of gas supplies and the cost of providing service. Methods for allocating the cost of providing service, including commodity and demand costs, can significantly affect rate design at both the distribution and pipeline level. Wisconsin Gas Company recommends that the rate design study consider methods for quantifying these costs (both marginal and embedded costs) and methods for their allocation to each customer-class and each component of rate design.

III. ADDITIONAL EVALUATION CRITERIA

In addition to the evaluative criteria cited in the Notice of Inquiry, Wisconsin Gas Company refers the ERA to the "criteria of a sound rate structure" listed by James C. Bonbright, in Principles of Public Utility Rates (Columbia University Press, New York, 1961). These include:

- Ease of public understanding.
- Effectiveness in yielding revenue requirements.

- Stability in revenues from year-to-year.
- Fairness in apportioning the costs of service between and within customer classes.
- Avoidance of undue discrimination.
- Discouragement of wasteful use while promoting justified use.

Additionally, Wisconsin Gas Company believes that the study should consider the following areas when evaluating specific rate designs: changes in the demand for gas by certain classes of customers which could affect the ability of the distribution utility to manage peak day supply and demand, the cost of implementing and administering the rate design, and the effects on revenues such as revenue volatility due to changes in weather or business conditions and such as uncertain earnings due to the difficulty in estimating test-year demand and sales levels to each customer class.

IV. DEFINITIONS OF RATES AND EVALUATIVE CRITERIA

Wisconsin Gas Company believes that the definitions of the rates and evaluative criteria are very important and recommends that ERA seek public comment on the definitions once they have been drafted. Specific definitions which may be troublesome include conservation, marginal cost, and equity.

V. OPPORTUNITIES FOR CONSULTATION AND COMMENT

The retail rate design study may well be a substantial factor in determining gas utility rate design for the future. A matter of such importance must be developed after full and frequent opportunity for affected persons to present views and engage in dialogue. The Congress intended such a process by mandating ERA to engage in "consultation" in this proceeding. Since public utility regulation in general and retail gas rate design in particular have not historically been matters of Federal involvement, the ERA should abide the consultation mandate by holding frequent informal conferences wherein it can become acquainted with local rate practices and where views can be exchanged and discussed. This process has been used effectively by the Federal Energy Regulatory Commission under similar mandate in its implementation of incremental pricing. Any interested person should be entitled to participate in the conferences, but individual gas utilities and state regulatory commissions, trade associations such as UDC, and regulatory commission associations such as The National Association of Regulatory Utility Commissioners should specifically be invited to participate.

When proposals emerge after the consultation process, the public should be afforded the opportunity to comment on the detailed work plan for the study, including the evaluation criteria and definitions, developed. The public should also be afforded the opportunity to submit independent analyses of the specific rate designs which will be considered by ERA.

Respectfully submitted.

WISCONSIN GAS COMPANY

By

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792226

Robert L. Lienemann
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June 29, 1979

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street N.W.
Docket ERA-R-79-22
Washington, D.C. 20461

In response to the Department of Energy's Notice of Inquiry in Docket ERA R-79-22, Peoples Natural Gas Division of Northern Natural Gas Company (Peoples) offers the following comments.

GENERAL COMMENTS

Peoples operates natural gas distribution systems in 319 communities encompassing basically an eight state area. Our experience in dealing with this large geographical area has shown that it is not often possible or desirable to treat all areas in the same manner. There are substantial differences in operating conditions, cost levels and customer attitudes that demand individual attention. This experience leads us to believe that any rate design policies which are designed to address national level problems are likely to result in serious inequities for some geographical areas and windfalls for others unless they are designed to be flexible and adaptable to local conditions. With some of the rate design schemes being considered, the same result may occur between customer classes within and between geographical areas. It appears the state regulatory commissions are in the best position to determine proper rate design to recognize local conditions.

Peoples has been informed that the basis for evaluation of the various rate design schemes will be the creation of an extensive model or models. The model(s) will be used to gauge the impact of various rate designs on the evaluative criteria mentioned in the notice. It is Peoples' opinion that a useful model of this type will be very difficult to create. Any model must take into account varying operating and geographic conditions in addition to recognizing the myriad interrelationships and impacts of changing rate design on all other activities of the utility.

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Peoples feels that those people responsible for creating the model and interpreting and evaluating results must have substantial input from the gas utility industry in order to gain useful results from the study. Substantial input may also be required from other groups such as gas producers, industrial customers, general service customers and others.

The study may result in the formulation of far reaching national policies which will impact the future of the natural gas industry. The study must have its theoretical conclusions tempered or complimented by practical considerations including the significant differences in geographical areas and operating systems across the country. Peoples believes that the ERA need only ask for input of this type from gas industry associations or specific companies and it will be arranged in the form of individual company participation or working committee groups.

RATE DESIGNS AND RELATED ISSUES

In general, Peoples feels that cost of service should be an important consideration when designing rates. Cost of service should then be tempered in terms of historic rate levels, value of service to the customer and customer acceptability and understanding. A final consideration would be the ability of the utility to economically administer the rates.

Cost of service by class of customer is, of course, subject to judgment and results can vary depending upon methodology and assumptions used. Peoples' opinion is that cost responsibility should be approached from the view of ascertaining which customers actually impose cost on the particular system involved. Nebulous theoretical consideration such as who should and should not be using gas or the arbitrary transfer of fixed costs to be recovered through variable rates to achieve some social objective, which is not supported by value of service concepts, tend only to complicate or destroy the true economics of operating a gas system.

Social objectives such as transfer of income should have no impact on rate design considerations, but should be accomplished through other means already designed to handle this type of problem.

RATE DESIGNS

Comments on some of the specific rate designs mentioned in the notice are as follows:

1. Incremental and/or marginal cost pricing - While incremental and marginal costs are two different economic theories, they often tend to end up at about the same place. There are many, many definitions and

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approaches to each theory. The main abuses related to these approaches are that they are often applied to only some classes of customers on a judgmental basis to gain some type of political or social advantage. The fact that utilities have a limited revenue requirement which is based on average costs, often results in subsidies between classes based on political motives. The idea that it is somehow less harmful to the public as a whole to load increases on the industrial sector is untrue. The costs end up being paid by the public in general through increases in the cost of goods and services despite the sector to which they are initially applied.

Another abuse of these theoretical approaches is that they are applied selectively as to the specific costs which are to be measured and priced in this manner. There is no justification for considering the incremental or marginal cost of buying another unit of gas at the wellhead without also considering the offsetting low incremental or marginal cost of pushing that unit through the pipeline and distribution system. It is also important to keep in mind that often the marginal cost of gas for distribution utilities supplied by a pipeline company is the commodity rate of the pipeline company. To assume the marginal cost of gas is something greater, usually causes problems in staying within the utilities' revenue requirements. The marginal cost theoreticians often try to solve this problem by proposing inverted rates. Inverted rates do not follow the cost patterns of most distribution utilities and also will cause greater risk through revenue instability.

The use of marginal or incremental costs in the industrial market or for new or expanded loads is also inappropriate in light of the use of average costing of competitive fuels such as oil. Proper resource allocation can not be accomplished through pricing techniques which employ marginal costs for one fuel and average costs for another competing fuel.

Also, as is becoming obvious in relation to the current provisions of incremental pricing in the National Energy Act, administration of rate levels can become very difficult.

2. Seasonal rate differentials - Differentials in cost due to supplying peak demand do exist to some extent and, of course, vary with geographical location. Rate differentials based on these costs may be justified for some operations. Related impacts must be considered however. Seasonal rates will certainly cause greater revenue

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instability and therefore higher capital costs to accommodate the higher risk involved.

The impact of seasonal rates in conservation is unknown. While theoretically they should result in more conservation, the already high level of wintertime bills may limit any additional impact. Also many utilities and regulatory commissions are encouraging customers to use "budget billing" plans which tend to dampen the impact of seasonal rates on conservation. Of course, customer acceptance of seasonal rates is expected to be poor as many high bill complaints are already being received without seasonal rates. We would expect high bill complaints to increase with seasonal rates.

3. Demand-commodity rates/declining block rates - Despite the "bad press" that declining block rates have been receiving over the past few years, when properly designed they are still the most cost reflective rate design available for application to large, somewhat diverse, groups of customers. Demand-commodity rates are also cost reflective when the demand component is properly derived. Demand-commodity rates are best used for larger firm customers where specific demand amounts can be identified for each customer.
4. Volumetric rates - Rates of this type can also be appropriate, again when properly designed. It is usually necessary to couple the volumetric rate with a fixed customer/system charge in order to properly reflect costs.

This type of design is sometimes abused by allocating an inappropriate amount of fixed cost to the volumetric rate instead of the fixed customer charge and thereby forcing the large and high load factor customers to subsidize other customers.

5. Lifeline rates - Peoples can identify little economic or social benefit of lifeline rates. As considerable literature on this subject points out, the benefit of rates of this type may not necessarily go to those who are supposed to benefit. Lifeline rates are not supported by costs and, in fact, should increase total costs to reflect the increased risks due to increased revenue instability. The social objectives of lifeline rates may be valid goals, but should be handled through existing or new welfare systems.
6. End user rate schedules - Peoples is not certain what is meant by this type of design, but feels that it may be appropriate at times to reflect in some rates the value of service related to end use. For

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instance, agricultural uses in many cases will rise to a higher curtailment priority which may justify an increase in rates to these customers to reflect this increase in value of service.

EVALUATIVE CRITERIA

The "Notice of Inquiry" mentions changes in total costs (including capital and operating costs) as a criterion for evaluation of the various rate designs. While the ERA may already have risk evaluations in mind, Peoples would like to expand somewhat on this subject. Major consideration must be given to the impact of each rate design concept on this risk of the utilities. How does each concept impact the likelihood that the utility will be able to earn a reasonable rate of return? Rate design schemes that arbitrarily load revenue requirements on highly temperature sensitive markets or onto volatile industrial markets, tend to increase the risk factors. Increased risk must be accompanied by increased capital costs.

Peoples appreciates the opportunity to comment on the gas rate design study to be performed by the ERA. As mentioned previously, any additional opportunities for comment or consultation concerning the study would be most welcome. Appropriate stages for such additional comment or consultation may be:

1. During the modeling process.
2. At the completion of the rate design study.
3. Prior to the drafting and submission of legislative proposals.

Sincerely,

R. L. Lienemann

SPfu

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

792227

Gas Utility Rate Design Study

Docket No. ERA R-79-22

COMMENTS OF
COLUMBIA GAS DISTRIBUTION COMPANIES

COLUMBIA GAS OF KENTUCKY, INC.
COLUMBIA GAS OF MARYLAND, INC.
COLUMBIA GAS OF NEW YORK, INC.
COLUMBIA GAS OF OHIO, INC.
COLUMBIA GAS OF PENNSYLVANIA, INC.
COLUMBIA GAS OF VIRGINIA, INC.
COLUMBIA GAS OF WEST VIRGINIA, INC.

Pursuant to the Notice issued May 3, 1979 by the Economic Regulatory Administration (herein called "ERA") in the above entitled matter, the Columbia Gas Distribution Companies herewith respectfully file these written Comments. The Columbia Gas Distribution Companies are Columbia Gas of Kentucky, Inc., Columbia Gas of Maryland, Inc., Columbia Gas of New York, Inc., Columbia Gas of Ohio, Inc., Columbia Gas of Pennsylvania, Inc., Columbia Gas of Virginia, Inc. and Columbia Gas of West Virginia, Inc. and request the opportunity to participate fully in the consultation and comment processes mandated by Section 306 of the Public Utility Regulatory Policies Act of 1978.

The Columbia Gas Distribution Companies are engaged in the purchase and sale of natural gas within their respective states, and therefore, are exempt from Federal Energy Regulatory Commission jurisdiction pursuant to Section 1 (b) and 1 (c) of the Natural Gas Act, 15 U.S.C. Section 717 (b) and (c). Each Company is a wholly-owned subsidiary of The Columbia Gas System, Inc., and each receives its principal interstate natural gas supply from a corporate affiliate, Columbia Gas Transmission Corporation ("Transmission"), a pipeline company subject to the jurisdiction of the Federal Energy Regulatory Commission.

Transmission delivers approximately 55% of its total deliveries to the Columbia Gas Distribution Companies, which, in turn, distribute gas to 2,400 industrial accounts, approximately 145,000 commercial accounts, and approximately 1,700,000 residential accounts within Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia. The Columbia Distribution Companies are subject to the jurisdiction of the state regulatory commissions of the states in which they operate.

Communications concerning this Docket should be addressed to each of the following:

Thomas E. Morgan, Esq.
General Counsel
Columbia Gas Distribution Companies
99 North Front Street
Columbus, Ohio 43215

Wallace R. Barnes, Esq.
Senior Counsel
Columbia Gas Distribution Companies
99 North Front Street
Columbus, Ohio 43215

Columbia will not undertake in these comments to address every issue under consideration in the Notice issued May 3, 1979. The Columbia Companies are members of the Ad Hoc group called United Distribution Companies ("UDC"), which is also submitting comments in response to the Notice of May 3, 1979. The UDC comments incorporate and amplify the position of the Columbia Companies, with respect to:

- (1) the extreme importance of every rate design to every distribution utility and all classes of customers;
- (2) the great care and restraint with which the Federal government must approach the injection of new rate designs into tariffs at the local level;

- (3) the consequent scope and course which this mandated study must take in order to be in the consumer and national interests; and
- (4) the necessity for distribution utilities to have full opportunity to present to ERA complete analyses of the implications of each individual rate design which is made the subject of the study.

Accordingly, the present comments of Columbia Gas Distribution Companies are limited to definitions of rate designs and evaluative criteria - the specific areas invited by the instant Notice.

Definitions of the Rate Designs

The following definitions and comments pertain to the rate designs listed in the Notice by the Economic Regulatory Administration in the Federal Register of May 3, 1979, at page 26005:

1. Incremental Pricing

Title II of the Natural Gas Policy Act of 1978 provides for comprehensive procedures to effect incremental pricing of the higher costs associated with the new pricing provisions (Title I) of the NGPA. The requirements of the PURPA study should address this issue within the context of this Congressional policy.

2. Marginal Cost Pricing

Marginal cost pricing prices all units of a commodity at a level equivalent to the cost of acquiring the last marginal unit of output to be sold.

3. Seasonal Rate Differentials

Seasonal rate differentials are rates charged by a gas utility which reflect the cost of providing service to a particular class of customers at different seasons of the year, to the extent that such costs vary seasonally for such utility.

4. Demand-Commodity Rate Design

A demand-commodity rate design reflects the two basic elements of cost recognized in the industry - the acquisition (commodity cost) of gas the transportation and delivery (demand cost).

5. Declining Block Rates

Declining Block Rates are designed to reflect economies of scale as fixed costs are spread across larger volumes of sales. Larger consumptions are priced at decreasing costs. Such rates reflect the extent to which the unit costs to the utility of providing gas service to a particular class, which costs are attributable to such class, decrease as such consumption increases during such period.

6. End-User Rate Schedules

End-user rate schedules are rates designed on a cost allocation designed to achieve a particular efficiency, social, or economic goal or consideration.

7. Interruptible Service

Interruptible service rates are rates for gas sold on a temporary, as-available basis.

8. End-use or Gas Consumption Taxes

Such taxes would be analagous to end-user rate schedules discussed in No. 6 above.

9. Volumetric Rates

Volumetric rates are a rate design which reflect a flat charge per Mcf for all usage.

10. Lifeline Rates

A lifeline rate schedule identifies a quantity of gas as essential consumption and prices such volume at a cost below the ordinary cost of service.

11. Inverted Rates

An inverted rate design requires increased prices for increased consumption, in excess of the cost of service for the particular class of customers.

12. PGA

PGA clauses are a mechanism by which gas companies recover, on a timely basis, the cost of acquiring gas, without requiring a complete and formal rate hearing.

Additional Evaluative Criteria

ERA identifies the criterion of "equitable rates to consumers" as an additional standard with respect to which rate designs and rate issues must be analyzed. This so-called additional evaluative criterion is listed in the aforementioned Notice as one of the purposes of the Public Utility Regulatory Policies Act of 1978. Accordingly, it is therefore equally appropriate to include the purpose of "optimization of the efficiency of the use of facilities and resources by gas utility systems" as an additional evaluative criteria.

The following additional "evaluative criteria" are offered:

- (a) the possibility of increasing reliance on foreign oil imports as a result of changes in the gas price structure.
- (b) the effects on development of new supplies from a reduced ability to market such supplies due to changed rate designs.
- (c) regional and geographic considerations
 - competition with alternate fuels -
 - competition between states.

The Columbia Gas Distribution Companies request full opportunity to participate in the study as it progresses and to respond to the proposals of ERA prior to their submission to Congress.

June 22, 1979

COLUMBIA GAS DISTRIBUTION COMPANIES

Columbia Gas of Maryland, Inc.
Columbia Gas of New York, Inc.
Columbia Gas of Ohio, Inc.
Columbia Gas of Pennsylvania, Inc.
Columbia Gas of Kentucky, Inc.
Columbia Gas of Virginia, Inc.
Columbia Gas of West Virginia, Inc.

By

Wallace R. Barnes, Its Senior Counsel

State of Wisconsin \ PUBLIC SERVICE COMMISSION

June 29, 1979

792228

CHARLES J. CICHETTI, CHAIRMAN
JOHN C. OESTREICHER, COMMISSIONER
EDWARD M. PARSONS, JR., COMMISSIONER
LEWIS T. MITTNESS, EXECUTIVE SECRETARY
HILLFARMS STATE OFFICE BUILDING
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FILE NO. ERA-R-79-22

Department of Energy
Office of Public Hearing Management
2000 M Street, N.W., Room 2313
Washington, D.C. 20461

Re: Gas Utility Rate Design Study; Responsibilities Under
Public Utility Regulatory Policies Act (PURPA) of 1978;
Docket No. ERA-R-79-22

Comments of the Public Service Commission of Wisconsin

Gentlemen:

The Public Service Commission of Wisconsin (PSCW) makes the following comments relative to the Department of Energy's (DOE) April 30, 1979 published Federal Register Gas Utility rate design study under Sec. 306 of Title III of PURPA.

1. In addition to the identified and alternate rate designs listed in the notice of inquiry, the Rate Study should study all major rate designs that may be contemplated for purposes of statewide exemptions from incremental pricing under the provisions of the Natural Gas Policy Act of 1978. Specifically, we suggest the study of benchmark rates and auction rates along with alternatives that may be proposed by other states seeking exemptions.

The PSCW intends to seek a statewide exemption from incremental pricing of the NGPA. We believe that our innovative gas rate designs are the types Congress intended to be considered in PURPA. Accordingly, we urge that the Congressional intent of the Gas Rate Design Study objectives be used to support statewide exemption for incremental pricing, and further that the Wisconsin approach to rate design be considered in the Gas Rate Design Study.

Benchmark rates and modified auction rates have been adopted in one utility and are under consideration for the remaining major gas utilities in the state. Benchmark rates are used to deal with the excess revenue problem when rates based on marginal costs would exceed the class cost of service revenue

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requirement. Excess revenue is rebated on historical consumption so as to hold the price for increased or decreased use at marginal cost. Auction rates are a multi-tier version of the FERC proposed three-tier alternative fuel price cap. This should clear the market of excess gas supplies, and further reduce shifting to alternate fuels, and provides an opportunity to tie curtailment priorities to price.

2. It is the understanding of the PSCW that consulting work already underway for the Economic Regulatory Administration is focusing on the impacts of the three-tier alternative fuel price caps. While this effort is not expected to cover all the Gas Rate Study, we urge that focus be shifted from impact studies to the theory, conceptual validity and comparative analysis of the various rate design alternatives.

It is further our understanding that the work underway is limited to pricing at the distributor level and that deadlines are such as to complete studies by the end of 1979. We believe that the same rate design questions should be addressed at the pipeline and wellhead level. Such studies will take longer to complete.

Current emphasis has been on pricing gas on the basis of the cost to (some) customers of their next best alternative. This has been necessary, at least in part, because we do not have an estimate of marginal resource costs for both commodity and demand at the pipeline and wellhead levels. This includes the cost of accelerated extraction methods versus leaving gas in the ground for later use. Judgmental estimates as to the split between commodity and demand have had to be made producing the Seaboard and United formulas. The PSCW believes that at least some attempt should be made to estimate marginal resource costs for the production, transmission and distribution of natural gas. If successful, such a study should satisfy some of the critics that charge a departure from cost-based pricing in the NGPA.

3. A Study should be made of differences in seasonal marginal cost. These differences would be affected by factors such as a) whether existing storage is used to capacity or if excess capacity exists, b) the value of gas used in the summer is affected by the possibility of storage and the value of use in the winter, and c) the optimization of storage capacity, including inducement rates to firm customers to go interruptible and thereby avoid building more storage.

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4. The Gas Rate Design Study should identify the marginal costs of major potential supplies of gas, including synthetic fuels, and make recommendations of how to flow through such cost data to consumers by means of price signals.

5. The Gas Rate Design Study should address what rate designs are necessary to eliminate any unsold surpluses of gas arising from NGPA incremental pricing or whether such surpluses should be left in the ground.

6. The Study should consider the merits of tying curtailment priorities to price rather than end use.

Sincerely yours,

Stanley York,
Chairman

Charles J. Cicchetti,
Commissioner

Edward M. Parsons, Jr.,
Commissioner

MR/dm

EBASCO BUSINESS CONSULTING COMPANY*A Division of Ebasco Services Incorporated*100 CHURCH STREET
NEW YORK, N.Y. 10007

782229

July 2, 1979

The Department of Energy
Office of Public Hearing Management
Room 3313 - Docket ERA-R-79-22
2000 N Street, NW
Washington, D. C. 20036

Dear Sirs:

Enclosed you will find some preliminary comments which constitute the response of Ebasco Business Consulting Company to your request for general comments related to the Gas Utility Rate Design Study as published in the Federal Register on Thursday, May 3, 1979.

We are pleased to have this opportunity to convey to you some general comments that might be of use to you in preparing for a Gas Utility Rate Design Study as required under the Public Utilities Regulatory Policy Act of 1978. We regret not having the time to respond to issues other than marginal cost pricing.

Very truly yours,

Dov Frishberg
Chief EconomistDF:ab
Enc.

792229

CENTRAL TOPICS IN MARGINAL COST PRICING OF GAS1. INTRODUCTION

Marginal Cost Pricing as a theoretical concept is a rather simple and straightforward proposition and constitutes an important part for the more general field of economics coming under the title of Microeconomics theory. Despite its simple and straightforward characteristics, its application and operation in various actual and realistic setting always entails great complication. In the past, in every economic sector for which margin cost pricing has been proposed, certain technical, economic, organizational, and financial matters have complicated the issue of marginal cost pricing and almost uniformly delay the decision on application rejection.

Ebasco Business Consulting Company (EBCC) has been involved in the last few years in the Electric Utility Rate Design Study, which is still ongoing and is approaching its final stages. In the course of its work EBCC has acquired considerable amount of experience and insight into the problems that might confront applications of marginal cost pricing to electricity and other industries that have similar economic characteristics. In addition, Ebasco Business Consulting Company encompasses decades of experience in economic, financial, and regulatory aspects of public utilities in the United States and other countries. We are thus led to believe that we are capable of making some preliminary comments related to the issue of marginal cost pricing of gas which may prove helpful in preparing the proceeding of a rate design study for gas supply. In what follows, we wish to discuss some central points that have either proven to be crucial and important to designing marginal cost prices in general to systems such as electrical power or gas, or that may have particular importance for the study of rate design for the gas industry and may have been of somewhat less importance when discussing economic rate design of electrical power.

2. NECESSARY CONDITIONS ELSEWHERE IN THE ECONOMY

If marginal cost pricing of gas, electricity, or any other goods and service in the economy is to be applied for the purpose of obtaining economic efficiency, an initial determination must be made to decide whether marginal cost pricing indeed promotes economic efficiency. Theory tells us that there are certain necessary conditions that relate to the production and distribution of other goods and services in the economy which must exist if marginal cost pricing of gas is to promote economic efficiency in general. In addition, our experience in the Electric Utility Rate Design Study has shown us that certain deviations from these necessary conditions are extremely hard and impractical to rigorously correct within a pricing mechanism, so as to adjust marginal cost prices for distortions in other sectors of the economy.

EBASCO BUSINESS CONSULTING COMPANY

3. CAPACITY CURTAILMENT COST AND A RELATIONSHIP TO CAPACITY COST

The greatest source of disagreement in the Electric Utility Rate Design Study, and in many other marginal cost study applications and considerations relates to the pricing and planning of capacity. Generally, marginal cost pricing under capacity constraints requires that, in any period of homogenous supply and demand, in addition to the marginal cost of producing the equilibrium quantity, prices should be increased, if necessary, to a level that which quantity demand will equal available supply. This new and somewhat revolutionary concept seems to produce a reluctance on the part of many taking part in such studies to apply hourly or half-hourly capacity charges. The accepted and traditional forms of rate design that had attempted in the past to capture the nature of the problem of capacity pricing and offered an intuitive solution that may refuse to admit has an alternative. Furthermore, the theory of marginal cost pricing under a capacity constraint (generally appearing in the economic literature) under the title of peak-load pricing produces certain results and about the level of optimal capacity that will be, or should, be installed under economically efficient pricing. For reasons somewhat hard to trace, most methodologies have looked at the result of these propositions and had used them in their various models to derive what they term capacity charges. We feel that it is necessary to clarify the interdependence and the independence of prices and capacity decision from a theoretical point-of-view at the outset of such a study, so that resources may be saved by not being allocated into an analysis which is based on an erroneous understanding of the theory and concepts involved.

4. RELIABILITY

An additional aspect of economically efficient pricing and planning which we had encountered in the past is that of reliability. This aspect of marginal cost pricing seems to appear in almost any application including transportation, communication, mail services, traffic flow control and production and distribution of gas and electricity. Yet, somehow, the proposed methodologies for application have been unsuccessful in bringing out the nature of the reliability constraint and its implication for marginal cost pricing. Frankly, we suspect this is due to the fact that the bulk of the theoretical writings on this matter are somewhat unrealistic, in both structure and assumptions. The articles which deal with this in a direct and proper manner are few, and often forgotten in the references to the body of literature on this issue. The methods used in calculating prices should, at least obtain the level of sophistication and development of reliability criteria and decision making that exists in the various planning and operation techniques that are now being used in these industries.

EBASCO BUSINESS CONSULTING COMPANY

5. VERTICAL INTEGRATION

An interesting aspect of marginal cost pricing in gas distribution is the problem of marginal cost pricing, or peak-load pricing, under vertical integration. This problem seemed not to exist in the study of marginal cost pricing of electrical power, because the studies under that topic concentrated on the cost at the generation level. Various "downstream" segments of the system in the transmission and distribution of electricity were largely neglected in the overall theoretical analysis or added on to the study of optimal economic rates in a way wholly disagreeable with the principles of marginal cost pricing. There may be justified reasons to support the neglect of these factors under marginal cost pricing when dealing with electricity, or to treat them in the way that they had been treated, but it seems that, by its nature gas supply systems are mostly vertically integrated capital investments and the problem of setting prices optimally with consideration of the economics of vertical integration becomes paramount. We have recently undertaken a theoretical study of these matters and find the working of the system and the results of the study to disagree on various matters with simple results obtained under the traditional model of marginal cost, or peak load, pricing.

6. METERING

As in other cases of proposed application of marginal cost pricing, the problem of metering and selecting the time periods in which various prices of gas hold becomes the central issue. In a nutshell, what everyone would like to do on this matter is to develop a cost/benefit analysis under which various proposals of pricing periods and metering cost will be evaluated relative to the economic gain reaped under the economically efficient prices that they allow. Some interesting matters related to the question of metering seem to have been neglected. These matters, in addition, seem to have somewhat greater importance in the case of the supply and distribution of gas than they had for optimal or economically efficient prices in electricity. The question that must be asked: Is what is the economic unit that is being sold to consumers, and therefore, what is it that the meter should be measuring? Varying energy content in a given volume of gas should reflect varying economic value attached to the quantities of output being sold to consumers and therefore, one must consider whether the metering should or should not be able to account for such variations.

7. MINIMUM COST ANALYSIS

In the past, a continuing propensity to employ the least-cost solution for marginal cost-pricing is clearly evident. Those involved with studying or evaluating proposals for efficient pricing seems somewhat insensitive to the difference between the minimum-cost solution and the optimum-welfare solution, as we know it in economic theory. Thus, we find methodologies and various rulings by regulatory authorities discussing at length the marginal cost and then suggesting to equate the marginal cost to the price, and thus promoting economic efficiency. Sadly, such is not the working of the marginal cost proposition. In economic theory, marginal cost is viewed as a function of the level of output and the multi-product firm, the marginal cost of a certain product is the function of the level of output of some, or all of the goods produced by the firm. The efficiency proposal on pricing, states that the levels of output should be varied upward or downward from any existing or hypothetical level to that level at which all marginal costs are equal to prices and, simultaneously, these prices lead to a quantity demanded of each good equal to that level of output.

The most common case in point is the use of linear programming model in their least-cost specification mode to produce so-called optimal, or efficient, economic prices. Clearly, the results of these programs produce marginal cost for given levels of output. They do not produce marginal cost for the optimal level of output. If one were to use least-cost solutions in general for certain economically efficient prices, or linear programming methods specifically, then an iteration procedure must be devised under which the shadow prices of the various levels of output are adjusted, step-by-step, so as to lead to the quantities at every point in time that produce marginal cost prices that in turn gives rise to a quantity demanded equal to the optimal level of output.

8. CUSTOMER CONNECTION MARGINAL COST

A common problem in moving from traditionally designed rates to innovative rate design based on economically-efficient prices are the simple, yet mostly unacceptable proposals, for dealing with fixed, one-time, marginal costs that relate to the connection of one or more customers to a distribution system. In other countries, or in certain extreme cases within the United States, the customer may be forced to pay the marginal cost of his connection to the distribution system, yet the structure of rates in general in the United States had developed along the line of charging some level of these costs to each customer or a group of customers by small payments spread over the period in which such a customer is connected to the system. Thus, the problem here seems to be not one of theory and its application, but regulatory acceptance.

9. INVERSE ELASTICITY RULE

A considerable amount of effort seems to be spent in the study of economically efficient prices and their application to public utilities on the topic of inverse elasticity rule. This rule, while mathematically elegant and impressive is always a) applied using method of gross simplification; b) applied using aggregation of various customer groups, which may or may not prove to be a supportable procedure under economic efficiency; and c) produce results that are highly sensitive to the values of the parameters employed in the calculation, when in turn it is uniformly agreed that the values of these parameters may in reality diverge considerably from the values specified in the calculation. Surprisingly, there are various other methods, such as fixed charges or rebate, or infer-marginal charges or rebate, which are not only easier to apply and based on far more reliable assumptions and parameters, but theoretically are preferable to the inverse elasticity rule in handling the matters of a deficit or excess revenue of public utilities. We would therefore recommend for any study of optimal pricing of the output of a public utility to initiate its study with a clear understanding of the inverse elasticity rule, its workings, its limitations, and its theoretical validity at the outset so as to avoid confusion and waste of resources.

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STATE OF MICHIGAN

WILLIAM G. MILLIKEN, Governor

PUBLIC SERVICE COMMISSION

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DEPARTMENT OF COMMERCE

WILLIAM F. McLAUGHLIN, Director

July 5, 1979

792230

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street, N.W.
Docket ERA-R-79-22
Washington, D.C. 20461

The Michigan Public Service Commission (MPSC) is pleased with the opportunity to submit the following comments in regard to the Economic Regulatory Administration's Notice of Inquiry in Docket No. ERA-R-79-22: Gas Utility Rate Design Study; Responsibilities Under Public Utility Regulatory Policy Act of 1978.

I. Customer Classification

The study of gas utility rate design at the distribution level first requires the classification and definition of various end uses of natural gas. The following classification of end uses is offered:

1. Domestic Uses
2. Space Heating
 - a. Residential
 - b. Commercial
 - c. Industrial
3. Industrial Processing
 - a. Direct Processing
 - b. Boiler Use
4. Agricultural
5. Miscellaneous
 - a. Air Conditioning
 - b. Swimming Pool Heating
 - c. Gas Lights
 - d. Electric Generation

The application of various forms of rate design methodology requires consideration of several issues related to the end use of various classes

of customers.

1. Domestic Uses

The domestic use of natural gas is defined here as that used for residential cooking, water heating, and clothes drying. The volumetric demand for gas for domestic uses is dependent upon size of family and appliance saturation. For cooking, the demand for gas is directly related to the size of the family. As the size of the family increases, the demand for gas increases. For water heating, two factors must be considered: the number of appliances and the size of family. The appliances could include gas water heater, gas clothes dryer, dishwasher and clothes washer. The size and ages of the family will determine the demand upon the appliances and the hot water requirements.

It should be noted that due to the climatological diversity of this country, the demand for gas will vary significantly on a seasonal basis. During the colder months, domestic use will be affected by heat losses from water heating storage tanks and hot water pipes due to the lower ambient temperature. Heat losses from these areas are subject to correction by conservation which then has the effect of reducing consumption.

2. Space Heating

Generally, space heating occurs when the average ambient temperature drops below 65 degrees F. The methods of providing space heating by natural gas are either forcing air across a heat exchanger or by radiation of heat from hot water. The distribution utility load demand for space heating is large during the colder months and must be given consideration in rate design along with supply and the availability of storage facilities.

a. Residential Space Heating

The natural gas required for residential space heating is a derived demand dependent upon temperature and housing stock. If each house were identical, then a correlation could be made to show that the demand for gas increases as the temperature decreases. Therefore, rates could be assigned by temperature zones. However, when housing stock is considered, the temperature zone becomes a minor factor in rate design. To support this statement, a comparison is offered of two areas in different temperature zones. The comparison involves customers in Detroit and Sault Ste. Marie, Michigan. The Degree Day Deficiency for a 30 year average in Detroit is 6186 and in Sault Ste. Marie it is 9223. The average annual consumption for customers in Detroit is 208 Mcf and for customers in Sault Ste. Marie it is 164 Mcf. The reason for this inverse relationship is due to housing stock.

The contrast is dramatic. Sault Ste. Marie homes are smaller, better insulated and tend to have modern heating systems. By comparison, Detroit has predominantly two types of housing stock, which have high energy demand. The worse case is the pre-1940 two-story homes which generally have no insulation, no storm windows and an old coal furnace converted to natural gas. If

this type of home has steam heat, it is generally the case that the steam pipes have corroded thus restricting the flow of steam to the radiators. A house of this type would require in excess of 100 Mcf during the coldest month of the year in Detroit. Many of these homes are owned or rented by people with low and fixed incomes.

The second type of housing stock is the pre-1950 homes built on a mass production basis during the boom expansion of large cities. The building standards these homes were constructed under required insulation far below current insulation standards. Conservation actions would reduce the demand of these homes.

The situation in Detroit is not unique to that city but is replicated in other large cities such as metropolitan St. Louis, Milwaukee, Cleveland and other similar cities.

b. Commercial Space Heating

Commercial heating is required for the comfort of people in office buildings and retail stores. Increase in gas prices have made the replacement of old, inefficient heating systems with modern systems cost effective. Thus the escalation of the price of natural gas has produced conservation in commercial heating loads.

c. Industrial Space Heating

The price of natural gas has encouraged industrial customers to use energy conservation techniques to reduce their loads. In some cases, industry has used heat from processing for space heating, thereby, eliminating their space heating load.

3. Industrial Processing

Natural gas is often the only energy that can be used in some processes, or as raw material in processing. For these industrial customers, any cost of gas will have to be paid to produce the manufactured product. It is ironic that this category of end use, which produces many of the essential inputs for agriculture, now is a lower priority in curtailment schemes than agriculture.

The pricing of energy has impacted industrial processing uses but may not have caused conservation efforts or processing technique changes. The cost of gas constitutes only about 3% of total operating cost for most industrial processors and therefore price increases have not had sufficient economic impact to cause conservation. The industrial processing uses requiring a high energy demand and a large operating cost has justified the investment in conservation techniques to reduce cost and energy usage.

In considering rate design for industrial customers, the end use and energy requirements must be gathered by subclassification to promote conservation and maintain production and labor force. The price of natural gas used as a boiler fuel has already been addressed by the Congress. The incremental pricing provisions of the Natural Gas Policy Act.

4. Agriculture

The term Agricultural usage has been used to cover a seemingly endless number of products. Some of these products are dog foods, paper products of all types, fertilizers, flower greenhouses, food processing, lumber, etc. The end use for agriculture must be limited to a specific definition such as related to agricultural products for human consumption. Agricultural products that can be classified as luxury items should not be given high priority or considered for reduced rates.

Where natural gas is used as a raw material in the manufacturing of fertilizers, consideration should be made for providing an incentive for alternate fuels, conservation and development of new processing methods.

5. Miscellaneous

a. Air Conditioning

Gas used for air conditioning may be a substantial load for some distribution utilities. For the Northern United States, the air conditioning load is minimal and is not a major factor in rate design.

b. Swimming Pool Heating

The load for swimming pool heating may not be a large load but is highly susceptible to control pricing. In this case, gas for residential usage above an allowance for domestic usage is priced higher under current MPSC Policy.

c. Gas Lighting

Regulations adopted by the Economic Regulatory Administration in Docket No. ERA-R-79-6 implementing the Power Plant and Industrial Fuel Use Act and State legislation has stabilized this load and will lead to its substantial reduction, if not elimination in the future.

d. Electric Generation

The use of gas for electric generation is basically restricted to peak load plants in Michigan. The distribution utilities are not dependent upon this type of load. Co-generation by industrial customers is a factor but that gas usage is generally considered as part of industrial use.

6. Summary

The classification of customers should provide for the segregation of customers into homogeneous rate classes. Consequently, if a rate class consists of only residential customers, then flat rates or inverted rates could be implemented. However, if residential customers were included with small commercial and industrial users in a general rate class, the implementation of new rate design forms may require reclassification of customers. However,

since each distribution utility operates in a different service area, and has different load characteristics, the development of uniform definition and classification does not appear feasible. These conditions must be considered and also that one rate design proposal may not be applicable to all operating distribution utilities.

II. Rate Designs

1. Incremental Pricing

The incremental pricing of natural gas is being implemented through Title II of the NGPA. The current problem is not so much the implementation of incremental pricing but at what level alternative fuel prices will be set and the incentives which will be created for these customers to switch to alternative fuels.

Alternative fuels and natural gas prices may or may not increase proportionally to each other. Problems may develop in retaining incrementally priced customers as natural gas consumers.

There appears to be a trend developing for State regulatory agencies to set the rates for incrementally classed customers at the alternative fuel prices to eliminate "maximum surcharge absorption capability". If incrementally priced customers find it advantageous to switch to fuel oil, it would add to the demand for imported oil.

2. Marginal Cost Pricing

The concept underlying marginal cost pricing is that the price charged should reflect the cost of producing one more unit. To implement this type of pricing would require detailed analysis of each distribution utility's operations and customer loads through duplicating system operations, simulation and mathematical models. The larger distribution utilities have the capability to determine marginal costs for rate design but smaller utilities may not have the ability or staff. To implement marginal cost pricing by distribution utilities would require State regulatory commission approval. Rather than try to institute marginal cost pricing immediately, causing regulatory administration problems, it may have to be a goal which is attained over a period of years.

3. Seasonal Rate Differentials

Seasonal rate differentials have been applied to different types of customers. Some of the methods of applying seasonal rate differentials are: (1) residential customer's consumption in excess of allocated usage for domestic use, and, (2) industrial customer's consumption during high system demand periods for usage in excess of low-system demand periods. In establishing seasonal rate differentials, the factors of system supply availability, storage facilities, system loads and class of customers should be considered.

4. Demand - Commodity Rate Design

Demand-commodity rate design would have to be limited to very large volume customers. The metering costs and other fixed costs for this type of rate are very high and may not be economical for small users.

5. Declining Block Rates

During the time of low priced gas and readily available gas, declining block rates were used to promote gas sales. Currently, the cost of gas that the utility is paying to the pipeline suppliers is in excess of 70% of each revenue dollar the utility collects from its customers. The reasons for declining block rates have passed.

For Michigan customers the shift from declining block rates to flat rates was made during the early 1970's at a time when the price of gas was less than \$1.50/Mcf. Also at this time the MPSC encouraged insulation programs so that gas customers could reduce their fuel bills. Studies in Michigan show that the implementation of inverted rates to residential customers would shift the greatest financial burden upon the low income people who are least able to avoid the impact of the price shift. (In considering the conversion from declining block rates to some other form of rate design, the impact of cost changes must be carefully analyzed.) The impact of price shift upon low income people could be dampened by implementation of conservation programs for these people.

6. End User Rate Schedule

This was in part discussed under classification of customers. In Michigan some low priority end users are served under special contract and are incrementally priced.

7. Interruptible Service

Interruptible service has provided a method to serve all firm customers when supplies are not available to meet the system demand. The utility that doesn't have the luxury of storage to draw upon to meet winter demand must depend upon having a large load that can be interrupted to meet the demand of high priority firm customers. Even with storage facilities the utility may require interruptible loads. The rate design applied to interruptible loads must consider the customer's ability to use alternative fuels and a rate level so that the customer will not switch wholly to alternate fuels.

8. Oil Displacement Rate

The nation is attempting to reduce the importation of oil. To effectively reduce the importation of oil would require current users of oil to reduce their usage by limiting production or changing processing methods or use an alternate fuel.

To reduce production would reduce the profit margin of the company, thereby reducing the labor force which is not in the nation's best interest. To change processing methods may be impossible or take months or years to accomplish and requires a large investment. For the short term an effective method to help reduce the need for imported oil would be to make natural gas available to current users of oil for processing by an Oil Displacement Rate, such as recently proposed by the MPSC Staff.

The Oil Displacement Rate is only a short term aid to reduce oil imports and should be in effect for only three to five years. During this period of time, the customer can obtain other fuels or, preferably, change processing methodology to reduce energy requirements.

III. Potential Impact to Distribution Utility

Several programs are available for gas users to implement gas conservation. These programs hopefully, will reduce the requirements for gas and provide more efficient use of natural gas. The implementation of incremental pricing and other rate designs will cause some customers to switch to alternate fuels. As the utilities' gas loads decline, the fixed or increasing operating cost of the utility will have to be carried by lesser sales volumes thus increasing unit costs.

As the price of gas increases to consumers, more will switch to other energy sources. In time, the only customers being served by a distribution utility will be those who are not capable of seeking other energy sources. These customers may be the low and fixed income families and some small businesses. Regulatory agencies must be able to have available utility service to natural gas users at a reasonable cost and in turn have distribution utilities provide that service safely at a reasonable profit. Also, regulatory agencies must control pricing so that the switching to alternate fuels will not cause undue shortages of those alternate fuels.

IV. Other Rate Studies

During 1978, the Department of Energy conducted a technical, economic and institutional study of key rate design concepts that might affect gas distribution companies. This study has been completed and presented to the Department of Energy but not released to the public. This report should be of value and of use in this rate study. The investment of effort and cost to develop this report should not be wasted by shelving the report. If the 1978 DOE Rate Design report is used as part of this study, the report should be made public for our review and comments.

Sincerely,

Daniel J. Demlow
Chairperson

UNITED STATES OF AMERICA
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

792231

In the Matter of

Gas Utility Rate Design Study:)
Responsibilities Under Public) Docket No. ERA-R-79-22
Utility Regulatory Policies)
Act of 1979)

AMENDMENT TO
PRELIMINARY COMMENTS OF
THE PROCESS GAS CONSUMERS GROUP
AND THE GEORGIA INDUSTRIAL GAS GROUP

On July 9, 1979, the Process Gas Consumers Group ("PGC") and the Georgia Industrial Gas Group filed with the Economic Regulatory Administration their preliminary comments in the above-captioned matter. Those comments are hereby amended for the sole purpose of adding the names of Bethlehem Steel Corporation and Owens-Illinois, Inc. as members of PGC participating in this proceeding.

Therefore, the members of PGC participating in this proceeding, all of whom are high-priority process gas users, include: American Can Company, Armco, Inc., Bethlehem Steel Corporation, Cone Mills Corporation, General Motors Corporation, Libbey-Owens-Ford Company, Owens-Corning Fiberglas Corporation, Owens-Illinois, Inc., and United States Steel Corporation. The list of Georgia Industrial Gas Group members contained in the July 9 comments remains unchanged.

Respectfully submitted,

Edward J. Grenier, Jr.
Glen S. Howard
Sutherland, Asbill & Brennan
1666 K Street, N.W., Suite 800
Washington, D.C. 20006
(202) 872-7800

Attorneys for
The Process Gas Consumers Group
and
The Georgia Industrial Gas Group

July 11, 1979

79-2231-44

79-2231-44

WISCONSIN GAS
July 3, 1979

80-800

792232

9 3:02

Mr. David J. Bardin, Administrator
Economic Regulatory Administration
2000 M. Street, N.W.
Washington, D.C. 20461

Re: Docket No. ERA-R-79-22
Notice of Inquiry, Gas Utility Rate Design Study;
Responsibilities under Public Utility Regulatory
Policies Act of 1978

Dear Mr. Bardin:

Wisconsin Gas Company is participating in this proceeding both as a member of United Distribution Companies (UDC) and individually. UDC and the Company filed comments on July 2, 1979. The purpose of this separate letter is not to address the issues raised in the Notice of Inquiry, but rather to re-emphasize suggestions concerning the approach ERA should use in this proceeding. The prospects of nationally legislated retail gas utility rates is frightening. Ratemaking is a complicated, sophisticated procedure and the techniques used and objectives to be met vary considerably from region to region, state to state, and among areas within the same state. Factors such as differences in supply contracts, storage and peak in gas supplies, numbers of interruptible customers, local regulations, weather conditions, types of customers, population and income patterns, and many other factors influence the rate design arrived at by a state regulatory commission. Formulation of public policy through retail gas rate design is a matter which belongs to the states and of practical necessity must remain with the states.

We recognize that the Congress has mandated the study which is the subject of this proceeding. We believe retail gas rate design is so complex and of such vital importance that ERA should not rely solely on written comments of interested parties and the analysis of its independent consultant. The Congress apparently foresaw the pervasiveness and complexity of retail gas rate design, for it provided in Section 306(a)(1) of the Public Utility Regulatory Policies Act that the Department of Energy should make its study

and report only "after affording an opportunity for consultation and comment by representatives of State regulatory commissions, gas utilities, and gas consumers, . . ." This statutory language clearly contemplates something more than affording opportunity for comment by interested parties; it requires consultation by DOE with interested parties in formulating and carrying out the study. We have recommended, and reiterate here, that ERA hold informal conferences at several stages of this proceeding so that informed input can be obtained at appropriate points.

Retail gas rate design has not been a subject of federal involvement until now. Consequently, the federal government has acquired little knowledge, experience or expertise in the art of rate design. On the other hand, the state regulatory commissions and the gas distribution utilities have been extensively involved in rate design since about the turn of the century. We cannot over-emphasize the importance of ERA consulting with these experts in informal conferences throughout this proceeding.

The informal conferences should be open to the public, but special invitations should be extended to selected state regulatory commissions, such as the Public Service Commission of Wisconsin, selected gas distribution utilities, and organizations such as the National Association of Regulatory Commissioners and UDC. These conferences should be of great assistance to ERA in acquainting it with retail gas rate design theory and methodology and in formulating and directing the scope and content of the ERA study.

The Federal Energy Regulatory Commission has utilized the informal conference approach very successfully in its rule-makings concerning implementation of incremental pricing.

In short, we believe the Congress intended and the complexity of the subject matter requires that ERA meet with the parties which we have identified and others at the very outset of this proceeding and at various stages throughout in formulating the scope and content of the rate design study. When proposals emerge after the consultation process, the public should be afforded the opportunity to comment on the detailed work plan for the study, including the evaluation criteria and definitions, developed. The public should also be afforded the opportunity to submit independent analysis of the specific rate designs which will be considered by ERA.

Very truly yours,

WISCONSIN GAS COMPANY

By

N. J. Lesse-Young
Vice President,
General Counsel and
Secretary

CALIFORNIA ENERGY COMMISSION

1111 HOWE AVENUE

SACRAMENTO, CALIFORNIA 95825

(916) 920-6103

June 29, 1979

Department of Energy
Office of Public Hearing Management
Room 2313
2000 M Street, N.W.
Docket ERA-R-79-22
Washington, D.C. 20461

RE: GAS UTILITY RATE DESIGN STUDY; RESPONSIBILITIES
UNDER PUBLIC UTILITY REGULATORY POLICIES ACT OF
1978, DOCKET ERA-R-79-22

67:667000

600-100-1000

Dear Sir:

Enclosed please find ten copies of the comments of the California Energy Commission for the docket named above.

The technical content of these comments was prepared by John Wilson, Economist, California Energy Commission, 1111 Howe Avenue, Sacramento, California, 95825. If you have any questions concerning these comments, please call him at (916) 920-6081.

Sincerely,

James A. Walker
Executive Director

Enclosure

COMMENTS ON ECONOMIC REGULATORY ADMINISTRATION
NOTICE OF INQUIRY ON GAS RATE DESIGN STUDY

792233

The Economic Regulatory Administration's Notice of Inquiry (Federal Register, May 3, 1979) sought comments on the U.S. Department of Energy's "duties, responsibilities, and authorities" under Title III, Section 306 of the Public Utility Regulatory Policies Act. Specifically, ERA is seeking comments on the rate designs to be considered and criteria to be used in the gas rate design study that will be the basis of legislative recommendations to Congress. The staff of the California Energy Commission (CEC) has reviewed the background information in the Notice, and wishes to express its interest and concern in the "evaluative criteria" used in the proposed gas rate design study. The staff of the CEC finds the criteria listed in the Notice not useful for evaluating gas rate alternatives with respect to the purposes specified in PURPA, and proposes additional or alternative criteria that the CEC has used in developing electricity pricing policies for California. With respect to alternative rate designs to be considered in the gas study, the CEC has generally endorsed the principle of marginal cost pricing, which is listed in PURPA (Section 306) and the Notice, as one of the alternatives to be considered. The Commission has no comments on marginal cost pricing to present at this preliminary stage.

I. DISCUSSION OF ERA "EVALUATIVE CRITERIA"

The Notice of Inquiry lists six criteria to be used with respect to the rate designs and related issues:

1. Pipelines and distribution load factors,
2. Rates to each class of user, including residential, commercial, and industrial users,
3. Change in total costs resulting from gas utility designs (including capital and operating costs) to gas customers and classes thereof,
4. Demand for and consumption of natural gas,
5. End use profiles of natural gas pipelines and distribution companies, and
6. Competition with alternative fuels.

This list was taken from PURPA, Section 306(a)(2), which Congress specified as a list of "factors" which the gas study should address (Section 306(a)(1)). It is not clear in the Act or the Conference Report that Congress intended the factors to be the criteria per se. In fact, the individual items probably are quite unsuited to be used as evaluative criteria.

Examination of the six factors reveals each to be either too vague, or not satisfactory goals given the purposes of the Act. Factors 2, 3, 4, and 6 are simply elements that describe gas price and demand, and are not in themselves usable as "criteria." That is, Factor 2 is customer rates, which without qualification as to what are good or bad rates provides no guidance on how to evaluate the alternatives.

Factors 1 and 5 have no clear relation to the purpose of the Act. Factor 1, pipeline load factor, is a statistic that describes the capacity utilization of an existing facility, but does not clearly describe the efficient use of pipeline facilities and definitely does not reflect the efficient use of gas resources themselves. Hence, maximizing load factor is too vague to be a useful criteria for rate design. Similarly, the end use profile (Factor 5) by company has no qualitative description that would yield an unambiguous evaluation.

II. CEC EVALUATION CRITERIA FOR PRICING POLICY

The California Energy Commission adopted a report, "Electricity Pricing Policies for California" (attached), that evaluated alternative cost and rate design policies. The evaluation criteria used was threefold:

1. Satisfying the Revenue Requirement

The Commission established that the basic priority of ratemaking is to meet the revenue requirement for the utility. The utility must earn a rate of return on investment which will maintain the financial health and stability of the company. However, the Commission also concluded that a wide choice of rate structures will provide revenues and earnings that will be neither too high nor too low.

2. Efficient Resource Allocation

The Commission recognized the important role of prices in promoting efficient use of resources in a market-based economy. By definition, prices based on marginal costs encourage customers to use energy which is worth the cost of production, and discourages energy use which is not worth the cost of the energy.

3. Fair Distribution of Cost

The accepted definition of fairness and equity in regulatory decisions (and other public policy decisions) is that the customer compensate the producer for cost incurred in relation to the benefits received. This concept of fairness parallels the objectives of obtaining adequate revenues and setting prices that encourage efficient use of energy. However, changes in rate structures and levels should consider customer expectations so that investments in durable goods in expectation of continuation of existing rates and rate forms are not lost.

The Commission found this criteria to adequately describe the rate design policy concerns in California, and to be successful in evaluating alternative rate design options for electricity. This framework is offered to ERA to supplement or replace the proposed "evaluative criteria" in the Notice of Inquiry.

III. FUTURE CONSULTATION

The Energy Commission supports the purposes of the Public Utilities Regulatory Policy Act and the intent of the gas utility rate design study. As such, the CEC appreciates the opportunity to comment on the ERA study as it progresses, and recommends that public workshops be conducted by ERA on the West Coast to facilitate involvement of interested parties.

COMMENTS

ON

"ICF GAS UTILITY MODEL"

"GAS UTILITY MODEL DATA OUTPUTS"

"SCENARIO DESIGN"

WISCONSIN PUBLIC SERVICE CORPORATION

P.O. Box 700, Green Bay, Wisconsin 54305

October 23, 1979

792237

Mr. Stephen S. Skjci
Chief, Regulatory Support and
Analysis Branch
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

Dear Mr. Skjci:

The simulation model which will be used to evaluate alternative retail gas rate structures appears to be limited in its ability to adequately evaluate alternative retail gas rate structures. Wisconsin Public Service Corporation presently utilizes a gas environmental impact study model to analyze alternative rate designs. However, it is severely limited in the reliability of the output due to lack of customer load data. It appears that the ICF Model will suffer from the same shortcomings.

Specifically, the following key data is not available for Wisconsin Public Service Corporation customers:

1. Load variation over time for the classes of customers and the system.
2. Price and income elasticities for the customer classes and for specific rate blocks.
3. Detailed cost estimates that can evaluate at what natural gas price will the industrial customer switch to an alternative fuel.

The lack of reliable data does not allow an accurate evaluation of alternative rate designs and we would not rely on quantitative results. At best it will allow a comparison of the effects of alternative rates based on the best guess of the underlying load data.

If you have any questions, please contact Mr. Bernie Vigue at (414) 433-1488.

Sincerely,

A. E. Pearson
Assistant Vice President-
Rates and Budgets

AEP/kv

199
STATE OF CONNECTICUT
DEPARTMENT OF BUSINESS REGULATION
DIV. OF PUBLIC UTILITY CONTROL

October 25, 1979

792238

Mr. Stephen S. Skjei
Chief, Regulatory Support and Analysis Branch
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Skjei:

Thank you for your letter of September 20, 1979 forwarding three draft documents submitted by ICF, Inc. to DOE for the development of the gas utility rate design study required by Section 306 of the Public Utility Regulatory Policies Act of 1978. We have reviewed this material and have a number of observations concerning the material contained in these three documents. The remainder of this letter serves to summarize our more pertinent observations concerning the material supplied to us.

As noted by ICF, "the ICF Gas Utility Model is being developed to evaluate the impacts of a variety of policy options on natural gas customers, distribution companies, transmission companies and producers." Our fundamental concern with the ICF model pertains to the ability of the model to accurately and realistically predict impacts. Based on the documentation enclosed in your letter of September 20, 1979, we have serious reservations.

One of our primary concerns relates to the estimates of class demands under a set of rates. Since the documentation enclosed in your September 20 letter does not present any detail pertaining to how class demands will be estimated, this area cannot be fully explored. Since the estimation of class demands is the touchstone upon which impacts of alternative policy options are determined, complete documentation and support should be presented pertaining to this area of the model. Until such time as documentation is available, evaluation of the model cannot be completed.

As set forth in the overview and preliminary model documentation, the ICF gas utility model suffers from what we consider to be the fatal assumption that perfect knowledge exists. This is not the case. Neither consumers, distributors, pipelines, nor producers have the ability to predict or react to events as contemplated by the model. The model suggests that consumer consumption decisions will be determined as a function of rate structure and unit charges under which gas service is pro-

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vided. As a result of these consumption decisions, distributor and pipeline company rates are established to recover their total costs of providing service. The model assumes that at any point in time supply and demand, and pipeline and distributor rates are in equilibrium. This assumption does not recognize the time required to change rates under existing regulatory policies. For example, if the implementation of a new rate structure were to reduce consumer demand, it would probably take at least six months for consumers to fully react to the new rate structure. Once consumers fully react, it would take at least 13 months for distribution and pipeline companies to determine the actual impact on sales due to the new rate structure. Once the actual impact on sales is determined, it will normally require in the minimum 7 to 14 months (depending upon jurisdiction) before revised rate schedules reflecting the change in sales can be made effective. During this entire period of at least 20 to 27 months, the rate structure in effect does not produce revenues equal to the distributor and pipeline companies' total costs. The ICF model assumes that at all times the rate structures in effect will produce revenues equal to total costs. Of course once the rate structure is adjusted to reflect the impacts on customer demands of the "original new rate structure", this process would be repeated. In our opinion, it is imperative that any utility model recognize to the maximum extent possible that perfect knowledge is not available and in the minimum provide realistic estimates of the full impacts associated with regulatory lag and reaction times.

Another of our primary concerns relates to the development of gas supply sources especially for pipeline companies. The ICF model selects sources of supply so that the indicated gas supply costs are minimized without regard to other factors which maximize the total long-term production of natural gas reserves while meeting system requirements. In order that the ICF model consider the maximization of producing gas resources, it will require in the minimum, consideration of deliverability and production maximization functions, allowables, and consideration of take or pay obligations by pipeline and distributor companies.

In addition, we find no evidence in the discussion of the model that consideration is given to the ability or capability of existing or future pipeline systems to transport the gas from the sources of supply to the market areas. Since the addition of new supply sources or a change in mix of existing sources may require additional investment and increased operating expenses, these factors should be explicitly considered by a model which attempts to evaluate impacts for as long as a fifteen-year time horizon.

As set forth in the preliminary model documentation, the ICF model of transmission companies does not recognize new investment, other than the "replacement" of depreciated assets. Based on our review of the equations contained in the documentation, it appears that the model does not permit the replacement of depreciated assets with plant constructed at today's much higher cost levels. Even if we accept ICF's assumption that excess capacity in the natural gas industry exists, we feel that new

facilities and plant investment will be required to meet new loads, offset declining wellhead deliverability, serve new markets, and attach new supplies. We feel the model should reflect these factors.

We are also concerned that even though ICF specified that the model is being developed to evaluate impacts on pipelines and producers, there is no reference in the material to indicate how impacts on these two sectors will be evaluated. We are especially concerned regarding the impacts on producers associated with the policy options to be investigated. It would be of little benefit to adopt policies in the anticipation of meeting specified goals if the goals cannot be achieved due to the inability or failure of a segment of the industry to produce the required gas volumes.

In the development of demand/commodity rates for pipeline companies, there appears to be at least two problems. The first relates to the classification of all costs as either demand or commodity and developing a schedule of rates on this basis. The restriction of the model to compute only demand/commodity cost and rates does not recognize the full range of the various rate forms that are in effect by pipeline companies. The second area of concern relates to the allocation of costs in the model for gas pipeline companies wherein according to the equations supplied with the preliminary model documentation, all costs, excluding purchased gas costs, are allocated on an all-mile basis by FEHC are those costs related to transmission system facilities and then only on those pipeline systems where FEHC has determined that distances of haul should be recognized. Other system costs are normally allocated on a number of bases including average three day coincidental peak demands, winter requirements, and annual sales.

In the allocation of costs on the distribution companies, the overview and preliminary model documentation states that "all rate base expense and return on investment items are allocated to the six rate classes using a variety of allocation factors. These factors reflect utility practices and are derived in each iteration of the distribution model from the demand schedule data." We do not feel that the basic allocation factors as specified on Page 18, Section 4.4.2 and 4.4.3 reflect normal utility practices. In addition, we feel that in some cases the basic factors to be used are contrary to sound engineering and economic theory. In addition, we would take exception with the allocation of return on investment, especially the assumption that return on investment by class in the base year are representative of regulatory policy concerning relative burdens of investment return that should be borne by each rate class. This statement presumes that all factors in the base year conditions may not be in equilibrium, we would suggest that relative rate of return relationships be determined based on a comprehensive review of state regulatory policies.

In reviewing the memorandum dated June 22, 1979 pertaining to

gas utility model data outputs, we note that some of the data required in this particular model may be either unavailable or available only at extremely high costs to gas distribution companies. In addition, throughout this discussion, reference is made to marginal costs. We find no definition in the body of this particular memorandum concerning the definition of marginal cost. Before full evaluation of the ICF suggested model can be completed, a full and complete working definition of marginal cost must be developed. We would also take exception with the statement on Page 5 that load factor for gas pipelines and distributors does not have the same importance that it has for electric utilities. This statement illustrates a complete lack of understanding concerning the nature and operation of the gas utility industry. While the load factor question is certainly critical from the standpoint of the electric utilities, load factor may be even more important in the natural gas industry.

We feel that the ICF gas utility model needs a great deal of work if it is to properly evaluate the impacts of policy options on natural gas customers, distribution companies, transmission companies and producers. In our opinion, it is overly simplistic and needs to more fully recognize the dynamic and complex structure of the industry.

We appreciate the opportunity to respond in this matter and would be pleased to answer any questions you may have. This review has been provided by our staff consultant, Black & Veatch.

Sincerely,

Charles T. Caprino
Director, Rate Analysis,
Statistics and Research

CTC:jh

One of the NICOR
Basic Energy Companies

NORTHERN ILLINOIS GAS

203

P.O. Box 190 Aurora Illinois 60507 Phone 312 355 8000

August 16, 1979

Mr. Stephen S. Skjei
Chief, Regulatory Support
and Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
2000 M Street, NW
Washington, D. C. 20461

79224D

Mr. Colin C. Blaydon
ICF Incorporated
1850 K Street, NW
Suite 950
Washington, D. C. 20006

Dear Steve and Colin:

Let me set down in writing, with some minor amplifications, the comments which I made at the conference last Thursday with respect to the gas rate design study.

A. With respect to the memorandum of July 16 on scenario design,

1. The combination of high production and demand, or of low production and demand may not be reasonable. We should surely examine combinations of high production with low demand where incentive prices stimulate the former and retard the latter, and a combination of low production and high demand where inadequate wellhead prices limit the former and stimulate the latter.
2. With respect to the sensitivity variables affecting new demand the question of hookup moratoria may (at least temporarily) be academic as the gas supply situation brightens. In any event other factors that should be considered as variables are the cost of alternatives for various classes of users, changes in the level of business and industrial activity, and the impact of EPA regulations on industrial alternative forms of energy.

3. Under demand considerations a statement is made that "only the retrofit conservation programs will have an impact on preexisting demand levels". I can anticipate situations where the economics of installing new equipment, sometimes involving a conversion to an alternate form of energy, may be better than the economics of retrofit on existing equipment.
4. It should be recognized that certain types of large commercial customers are more closely comparable to industrial uses than to residential.
5. In analyzing alternative fuel prices as they impact industrial demand for gas, attention should also be paid to coal as well as fuel oils.

B. With respect to the June 14 memorandum on utility data sets,

1. There are a few other characteristics which may be significant such as the percentage of total supply represented by purchases from pipelines, other operating and maintenance expenses per customer, the ratio between industrial rates and prices of alternative energy forms.
2. As was expressed by numerous participants at the conference I share the concern about the adequacy of using only 5 companies (or models) for the study, which in my opinion will not adequately represent the major variations in the gas utility industry.
3. It is clear that in analyzing seasonal temperatures for the selected companies, that actual degree days for some recent year (probably 1978) were used; it may be more logical to use normal degree days to avoid fluctuations which differ between regions for a specific year.
4. The statement is made that "we have not found any significant difference that appear to correlate directly with size within the ranges we have reviewed". It is apparent that the ranges have not been wide enough; I am convinced that economies of scale exist particularly with respect to other operating and maintenance expense per customer.

5. I should point out that in the list of "candidates" to examine shown on Table 5, that 9 of the 18 companies are combination gas and electric companies which is an abnormal distribution. There can be significant differences of philosophy between combination and straight gas companies which will have an impact.

C. With respect to the memorandum of June 22 on model data outputs,

1. I recognize the desirability of providing in advance some indication of the nature of the outputs, but I hope that this remains flexible so that it can properly reflect logical implications as the study proceeds.
2. I am sure you recognize some of the interrelationships between the various measures listed on the first page. Clearly rates and revenues are interrelated, rates and typical bills and volume of sales are interrelated, and revenues and rate of return will correlate in some cases. It also seems likely that cost responsibility or causation should receive some consideration.
3. I should point out that revenue stability alone is not a major criterion, unless combined with income stability.
4. Utility capital costs are incurred not only to replace depreciated plant and to add new customers, but also enlarge gas supply.

D. With respect to the overview and preliminary documentation of the model,

1. The so-called distribution loop does not seem to provide for analysis of storage owned and operated by distribution companies, does not seem to make provision for supplemental supplies produced by distributors, and implies the use of price elasticity measures which, for local distribution company service areas, are extremely difficult to measure with any degree of reliability.
2. With respect to output data I am sure you are aware of the numerous ways in which rate base, revenue deductions and class rates of return can be measured for different classes of service.

3. At least one of your models should include a situation in which there are no interruptible sales; there are companies, like ours, for which this is presently true.
4. The treatment of working capital in rate base differs significantly among various state jurisdictions and alternative procedures should be allowed for.
5. In measuring demand costs the possibility of using some time frame other than the single peak day should be recognized.

As I pointed out at the conference I would be most happy to participate actively in offering comments and suggestions on this study as it progresses. Feel free to call me anytime that my input may be desirable.

Sincerely,

A handwritten signature in dark ink, appearing to read "D. Parson", with a long horizontal flourish extending to the right.

Daniel Parson
Assistant Vice President

DP/dsk

cc: Mr. Charles R. Montgomery
Mr. Robert W. Kearby
Mr. Steve Rodgers

COMMENTS
ON
"INTERIM MODEL DEVELOPMENT REPORT WITH
EXAMPLE CASE ILLUSTRATIONS"

National Food Processors Association
1133 Twentieth Street N.W., Washington, D.C. 20036
Telephone 202/331-5900

November 13, 1979

Department of Energy
Office of Public Hearings Management
Room 2313
2000 M Street, N. W.
Washington, D. C. 20461

797231

Re: Docket No. ERA-R-79-22/Gas Utility Rate Design Study

COMMENTS OF NATIONAL FOOD PROCESSORS
ASSOCIATION ON INTERIM MODEL
DEVELOPMENT REPORT

The National Food Processors Association (NFPA) submits these written comments in response to the ERA's October 16 letter inviting comments on the Interim Model Development Report and the underlying Gas Utility Rate Design Study.

The NFPA is a nonprofit trade association whose members account for 90 percent of the United States' production of canned foods. Canning converts perishable foods, in most cases harvested on a seasonal basis, into nonperishable form. Food processors have no choice but to use energy to convert unstable and unstorable foods into nonperishable form at the time that the foods are harvested.

As set forth more fully below, NFPA believes that the proposed rate model is inequitable if applied to food processors because food processors cannot modify their energy-use pattern. Aside from its fairness, the proposed rate model is contrary to the PURPA and to other federal legislation enacted along with, and intended to be complementary to, the PURPA.

This rate model formulation effort is being undertaken pursuant to Section 306 of the Public Utility Regulatory Policies Act of 1978 (PURPA), which requires the Department of Energy to submit to Congress a retail utility rate design study by May 1, 1980. The PURPA requires that any natural gas rate design formulated must be "equitable," PURPA Sections 2, 301, and must consider the effects of incremental pricing contemplated under the Natural Gas Policy Act of 1978 (NGPA) upon classes of users. PURPA Section 306. Thus the PURPA is not intended to be understood or enforced in the void, absent consideration of its companion legislation, the NGPA. The agencies of the Department of Energy have thus far worked in collaboration in discharging the responsibilities under the two Acts.

The use of natural gas for the processing of food has been certified as an essential agricultural use in the final rule issued by the Secretary of Agriculture under Section 401 of the NGPA (44 Fed. Reg. 28782, May 17, 1979). The conference report on the legislation explains that one of the reasons for the priority on this relatively low-cost fuel is "to prevent unnecessary increases in the cost of food in this country." H.R. Rept. No. 95-1752, 95th Cong. 2d Sess. 114 (1978). Under Section 206 of the NGPA, the use of natural gas to produce and process food is also exempted from the incremental pricing provisions of the NGPA. Food producers thus have a special status as a class of users who should be insulated from soaring energy costs.

The PURPA's provisions recognize that among the problems contributing to our nation's energy difficulties is the often needless concentration of energy use into particular time periods of the day and of the year. Such use requires energy production facilities larger than are necessary to meet average daily energy needs.

This excess energy production capacity contributes to the high cost of energy. The high cost of energy in turn contributes to the nation's inflation both directly, when energy is "spent" by users, and indirectly -- by adding to the cost of the necessities of life, such as food, which require energy use to be rendered to a storable form.

The PURPA therefore looks to rate designs that incorporate incentives for the reallocation of energy use to times of the day or year when full energy production capacity is under-utilized. But such designs are sensible only if, and will be successful only to the extent that, the users of energy are in fact elastic with respect to the time of use. If they are inelastic then no incentive will serve its purpose. Rather, with respect to the inelastic user, so-called incentives are in fact simply penalties that impose added costs upon the activity in question. The Conference Report accompanying the PURPA, S. Rep. No. 95-1292, 95th Cong. 2d Sess. 79 (1978) recognizes this distinction and suggests a solution:

" . . . A less than proportionate increase in rates at the peak may be appropriate to send the signal to the consumer to reduce elastic demand for peak energy without causing unnecessarily high rates which have no effect on inelastic demand at the peak. "

The use of rate formulas that penalize energy users forced to consume energy at certain times by the nature of their enterprise is not "equitable." In the case of food processors, operating on a high-volume low-profit-margin basis, the indiscriminate application of rate formulas that cause unnecessarily high rates also serves to increase unnecessarily the cost of food in this country. The rate design study model offered for comment in this Docket thus fails to account adequately for the national policy objectives expressed in PURPA - to establish

equitable rates - and in the NGPA - to prevent unnecessary increases in the cost of food in this country.

The rate design model should account for classes of users unable to take advantage of incentives to shift use of energy to different time periods. See PURPA, Section 306(a). When the class of user is affected with a national interest explicitly stated to be the prevention of unnecessary cost increases to their product, such as is the case with food processors, a rate design model that fails to take account of the inflexibility of energy use and that thereby unnecessarily increases costs would defeat the stated Congressional intent.

Respectfully submitted,

A handwritten signature in dark ink, appearing to read "Leonard K. Lobred". The signature is fluid and cursive, with a large initial "L".

Leonard K. Lobred, Director
Industry and Trade Regulations

COLUMBIA GAS DISTRIBUTION COMPANIES

89 NORTH FRONT STREET

COLUMBUS, OHIO 43215

THOMAS E. MORRIS
SECRETARY AND GENERAL COUNSEL

November 26, 1979

Mr. Stephen S. Skjei
Chief, Regulatory Support and Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
United States Department of Energy
Washington, D.C. 20461

792235

Re: Fourth "Interim Model Development Report With Example Case
Illustrations" (ICF Incorporated, October 10, 1979)

Dear Mr. Skjei:

By memorandum dated October 16, 1979 under your signature, a copy of the above-referenced document was forwarded to the undersigned, Secretary and General Counsel, Columbia Gas Distribution Companies, (hereinafter, "Columbia") with a request for comments on the fourth report, and preceding reports, "by the end of November". Columbia welcomes the opportunity to comment.

As a point of departure, Columbia notes that the gas utility rate design study of which this computer model development is a part, is being undertaken by ERA pursuant to Section 306(a) of the Public Utility Regulatory Policy Act of 1978, in order to submit proposals to Congress to "improve gas utility rate design and to encourage conservation of natural gas", Section 306(b).

If the gas utility rate design study is intended to result in a recommendation for a uniform rate design mandated by Federal statute, Columbia submits that ERA should reconsider the efficacy of such a goal. In this regard, please consider the conclusion reached by H. Zinder & Associates in their "Final Report on Contract EC77-C-01-8680" (March 12, 1979) at page 11:

The design of gas rates has evolved over the years to meet changing conditions; generally new rate forms have been developed and put into effect when the time was ripe for them. In view of this history, it might be wise to allow rate design to continue to develop to meet changing conditions, rather than to adopt an economic basis for rates and require all State regulators to adhere to them . . .

And at page 15 of the Zinder report appears the following expansion of this thesis:

Because of the fragmented nature of the gas industry -- separate production, transmission and distribution components -- and the various conditions that may prevail in separate utility service territories, the Federal government should refrain from seeking uniform adoption of any of the proposed reforms . . .

Columbia subscribes to this philosophy.

General Comments

The rate forms which have been addressed by ICF, Incorporated to date, the basic logic of the transmission and distribution loops and the detailed specifications evidence a good deal of thoughtful preparation. Columbia encourages the development of computer models for gas utility rate structures.

Columbia submits that the present documentation furnished to it concerning the ICF model is too sketchy to permit a detailed critique. One thing is clear. The best models evolve through continuing development efforts. Imponderables, such as technological advances, political climate and changes in world economic conditions will in all likelihood render long term conclusions meaningless. Therefore, great care should be taken in applying the results of the model derived from application to synthetic utilities, to "real world" applications.

Specific Comments

1. In Sections 1.1 (Transmission Loop - Well Utilization) and 3.1.1 (Optimal Distribution Supply Routine - Supply Specification) the variables considered are maximum and minimum volumes, demand and unit cost. Various supply tiers (cheapest first) are utilized until gas requirements are met. The last tier utilized would be only partially used; no apparent method to reallocate the fixed costs of the last supply tier has been considered.

2. In Section 3.1.3 (Interruptible Sales) and in other areas where demand is price-related, the demand module apparently assumes that a "cap" price exists, above which fuel switching will occur, but below which it will not occur. This is an incorrect assumption, even in a "firm load" situation. Customers have options in addition to fuel switching and conservation which will affect the demand of that class for gas service. Factors such as self-help gas and customers profitability considerations make the demand-price relationship a continuous rather than step type function. Columbia submits that fuel switching and resultant loss of load will inevitably occur at levels well below the "cap" or alternate fuel price.

3. As presently constituted, the model incorporates storage in the distribution loop. Columbia notes that the storage function is sometimes lodged with the transmission operation. Provision should be made in the model to deal with this fact.

4. The use of synthetic utilities seems a reasonable approach in giving examples of model output, but Columbia is concerned that rates suitable for a hybrid would not necessarily fit the wide variations in market area characteristics and corporate structure. More specifically, the model must consider the special circumstances of holding companies. Another concern under this ambit is the ability of the model to deal with strictly cost of service pipeline companies, and inter-woven as contrasted to "straight line" (Mcf - miles) pipelines. Nor is it clear that the model is designed to deal with distribution utilities having synthetic gas or propane facilities.

5. The rate Module, which should contain the utmost degree of flexibility and sophistication, is not sufficiently explained and documented to inspire confidence. For instance, working capital is reduced to a 1/8 formula not necessarily recognized in all states, nor necessarily adequate for all utilities.

6. The model appears to give no consideration to diversity of supply. The conclusion which might be drawn, that rates for firm load are minimized in the absence of interruptible load, could prove dangerous during a colder-than-normal winter or period of supply disruption. Columbia notes that interruptible load offers a distribution company some degree of protection for its firm load supply.

In closing, Columbia notes that its ability to test the validity of the model ultimately rests on the opportunity for it to use the model and observe its response to various input conditions. Therefore, Columbia requests that utilities be afforded access to the model, perhaps on a time-sharing basis, so that each utility can input its own data rather than rely on the input of a synthetic utility. Columbia also takes this opportunity to indicate its willingness to meet with representatives of DOE and/or ICF, Inc. to further detail its concerns about the computer model, and work with you in any area where we can be of assistance.

Very truly yours,

Thomas E. Morgan

COMMONWEALTH OF VIRGINIA

JUNIL L. BRADSHAW
CHAIRMAN
PRESTON C. SHANNON
COMMISSIONER
THOMAS F. HAWKINS, JR.
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CLERK OF THE COMMISSION
BOX 1197
RICHMOND, VIRGINIA 23201

STATE CORPORATION COMMISSION

December 4, 1979

Dr. Stephen S. Skjei
Chief, Regulatory Support and
Analysis Branch
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

792236

Dear Dr. Skjei:

This will acknowledge receipt of: (1) your letter dated September 20, 1979 enclosing 3 draft documents submitted by ICF for development of the gas utility rate design study as required by section 306 of PURPA, and (2) your letter dated October 16, 1979 submitting a copy of the fourth interim report for this study.

After reviewing these materials, it is obvious that considerable time and effort has been expended in their development. The model appears to be a useful tool for those gas utilities and regulatory Commissions who may choose to use it in making determinations regarding the necessity for major revisions in existing rate structure.

I have no suggestions for improving the effort or the goals and objectives of the study; however, an issue which I think the study should address is whether or not there is a real need for such a study with respect to the rates of gas distribution companies under the jurisdiction of state regulatory authorities. While I realize that your agency is responding to a mandate from Congress, I question the need for developing a model intended for use by gas distribution companies which have been operating for years under state regulatory jurisdiction.

As a Commission Staff Member and as a citizen of the U.S.A., I feel significant concern that Congress has directed that Federal agencies become so deeply involved in regulatory matters which traditionally have been handled at the state level.

From reading certain provisions of PURPA and certain portions of the materials submitted for comment it seems that the authors either are not fully aware of, or have ignored the rate making responsibilities of the State Regulatory Commission with respect to establishing appropriate rates for natural gas distribution companies under their jurisdiction. The Virginia State Corporation Commission is one of the older regulatory Commissions in the nation.

Dr. Stephen S. Skjei
 December 3, 1979
 Page 2

It has been empowered to establish rates for public utility companies in Virginia since it was created under the Constitution of Virginia adopted in 1902. The ratemaking responsibilities and other powers of the Commission were reaffirmed when the people of Virginia adopted a new constitution in 1970.

Many gas companies in Virginia have been providing gas service for more than 100 years. Their rates for gas utility service have been regulated by this Commission for decades. I am sure other states have similar experience. Therefore I honestly do not believe there is a need for the Federal Government to become involved in rate design or basic rate structure or other aspects of natural gas service provided by distribution companies operating under the jurisdiction of their respective state regulatory authorities.

The process of establishing appropriate rates is a continuing process. Utility rates in Virginia are constantly under review either on a formal or informal basis. Revisions of varying magnitude are frequently required in formal proceedings before the Commission. However, the Commission is aware that sudden or drastic rate changes may create problems rather than solve problems. From decades of regulatory experience this Commission has knowledge of the characteristics of individual companies under its jurisdiction. It knows that there are similarities between gas companies, and that there are significant differences regarding various aspects of gas company operations as the model recognizes. However, from its experience and its intimate knowledge of each company the Commission also recognizes that quite often there are certain unique factors characteristic of individual companies, and difficult to include in a purely analytical process, which must also be considered before a particular rate structure is approved and rates finally established for a company.

While the Virginia Commission does not always follow the advice and recommendations of its staff, should the occasion arise, I would recommend to the Commission that it strongly oppose any mandatory requirement that the model in question be used in analyzing the rates of gas companies in Virginia with a view toward requiring at the federal level, major changes in rate design for the Virginia gas companies. As previously stated, this Commission already is requiring or authorizing changes in rate structure and rate design when necessary.

Also, for the past several years the Commission has stressed the importance of conservation of energy and has required gas companies under its jurisdiction to maintain active conservation programs to benefit their customers stressing methods of conserving energy and economy of usage.

Thank you for the opportunity to comment regarding these proceedings.

Very truly yours,

Ryland Y. Bailey, Senior Engineer
 Division of Energy Regulation

PREPARED REMARKS

OF

CHARLES R. MONTGOMERY

PRESIDENT OF MICHIGAN CONSOLIDATED GAS COMPANY

ON BEHALF OF THE

AMERICAN GAS ASSOCIATION

BEFORE THE

DEPARTMENT OF ENERGY

January 15, 1980

The American Gas Association (A.G.A.) is a national trade association comprised of over 300 natural gas transmission and distribution companies. A.G.A. member companies serve approximately 160 million customers in all 50 states. These sales amount to about 85% of all gas utility sales in our nation.

We welcome this opportunity to discuss the interim reports relating to the gas utility rate design study required to be undertaken by DOE pursuant to Section 306 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Let me reiterate that, in our ongoing discussions regarding the study, the members of the A.G.A. Rate Reform Task Force are available for consultation. Moreover, we welcome and appreciate the opportunity to work with ERA and ICF personnel involved in this endeavor.

The primary purpose of our appearance this morning is to offer a detailed and constructive analytical critique of ICF's "Interim Model Development Reports" regarding the natural gas rate design study. A summary of the conclusions in this critique

follows these general remarks. The critique in its entirety appears as an attachment in Appendix A.

The A.G.A. firmly believes, and our analysis of the ICF model clearly supports, that even the best efforts of highly skilled men and extremely complex technology cannot achieve the objective of a national model that will properly produce a rate design for application to any particular utility. Gas utility companies are highly unique in character and have uniformly individual rate requirements.

Furthermore, the specific goals of PURPA, (viz., conservation, efficient utilization of resources, and equitable rates for consumers) cannot be accomplished by standardized rate design criteria imposed on a nationwide basis. These goals can only be accomplished at the individual gas utility company level through review and analysis performed working with the particular local regulatory authority. This is true because, although we are a national industry, there is an extensive amount of diversity from company to company and state by state. Specific identifiable factors which account for this diversity include differences in: demographics in market mix in the service areas; the number, kind, price and availability of competitive fuels in each market area; environmental and economic factors; varied appliance uses; geographical and climatological conditions; social conditions; and a variety of political considerations. Extremely significant to this divergence is the fact that not all gas utility companies are supplied entirely by interstate pipeline companies. Many have a mix of supplies including produced and purchased production, SNG, LNG, as well as storage capability. All of these differences must be considered and addressed at the local level.

With respect to the imposition of standards such as those included in Title I for the electric industry, it is also important to recognize the tremendous differences between these two industries. First, one of the vital differences is that the gas industry does not have the discretionary uses of its product that the electric industry does, i.e., there are not a great number and variety of appliances using natural gas. In fact, most state regulatory commissions impose restrictions on the uses of gas. Second, whereas electricity is a must in homes, and gas is not, the competitive posture of the fuels differs. Third, notwithstanding some degree of integration in our industry, we are for the most part a fragmented industry unlike the electric industry in which generally one company is the generator, transmitter and distributor of its energy. This is usually not the case in the gas industry because the producer, transmitter and distributor are by and large separate entities, and as such are subject to different regulatory bodies.

Perhaps the most significant difference however, lies in the infeasibility of storing large quantities of electrical energy and hence, the electric utilities need to have sufficient generating and distribution capacity to meet instantaneous demands of their customers. A gas utility, on the other hand, because it can store large quantities of energy, is concerned with customer peak day, seasonal and annual demands and the storage and other supplemental facilities necessary to meet these requirements.

This basic difference in storage, as well as the different use characteristics of gas and electric appliances, of necessity generate different cost considerations which appropriately result in differing types of service classifications and rate forms between the two types of utilities. Each utility and the market it serves is unique and the most effective regulatory response to any

specific local conditions at any given time can best be made at the state or local level.

Therefore, it is our position that it would be imprudent and ill-advised for DOE to recommend any standardized rate design to be imposed industry-wide on a national basis. Moreover, we do not believe there is any reason for DOE to recommend legislation to impose upon the gas utility industry requirements similar to those included in Title I of PURPA and applicable to the electric utility industry. At the time the PURPA legislation was being considered by Congress, A.G.A. opposed any such requirements for the gas industry because of the essential differences which then existed, and continue to exist, between the gas and electric industries.

Further, supporting our position that Title I type requirements should not be recommended for the gas utility industry is a DOE contracted study completed in 1979. That study stated that:

"[b]ecause of the fragmented nature of the gas industry--separate production, transmission and distribution components--and the various conditions that may prevail in separate utility service territories, the Federal government should refrain from seeking uniform adoption of any of the proposed reforms."*/

Moreover, in light of the apparent difficulties which will inevitably arise in the modeling efforts by ICF, we hope that DOE/ERA recognizes, as we do, the complexity of our industry and the inherent impossibility of constructing a general model with recommendations flowing therefrom which accurately assesses each utility on an individual basis.

*/ "Final Report to the Department of Energy on Natural Gas Rate Design," summary at p. 15, H. Zinder & Associates, Washington, D.C., March 12, 1979.

The natural gas industry is a growing and viable national industry. Indeed, in terms of capital investment, it is the fifth largest industry in the country. This is attributable primarily to vigorous retail level activity under existing state and local regulation. State and local regulators are capable of assuming a responsive posture in dealing with individual utility needs which are set forth above. Local regulators can react to these needs in a timely and effective fashion.

In addition, the task facing local regulators in determining gas utility rate design is not one which is reducible to a mathematical formulae. Cost of service, although not the sole criterion for establishing rates, provides an excellent guideline and starting point in all rate determinations. However, there are many other factors relevant in rate design assessment including: (1) the efficient utilization of resources; (2) the value of service provided; (3) the customer's ability to understand the rate design; (4) various socio-political and environmental factors; (5) historical demand assumptions and patterns; and, (6) gradualism in implementation of changes in existing rate structures. These are all factors which are more readily accessible and assessable at the local level by regulators "in tune" with a particular market's and utility's needs.

For these reasons, there is no particular rate form, or combination of rate forms, which is equally appropriate at all times and under all conditions. Changing circumstances require individualized and prompt responses by the regulatory authority if a utility is to remain economically viable.

A.G.A. wishes to emphasize the utmost importance of the Federal government exercising restraint in any recommendations it may make regarding the rate standards to be considered by state regulatory authorities which currently ensure that gas distribution utility rates are just, reasonable, and nondiscriminatory.

The full panoply of A.G.A.'s general concerns regarding the parameters and use of a gas utility rate design study are contained in our written comments on Docket No. ERA-R-79-22, filed on July 2, 1979 before ERA. I wish to incorporate by reference those comments in the record of these proceedings here today.

Let me now turn to the specific ICF Model results. Inasmuch as the most recent clarification of the ICF model was released late Friday, January 11, 1980, we have had an opportunity to make only a cursory inspection of that document. A more in depth review will be forthcoming and, contingent upon the need to file a written statement on this January 11 document, I now wish to reserve the right to do so in the future.

Regarding A.G.A.'s specific concerns with the "Interim Model Development Reports" released by ICF through October 10, 1979, I offer the following summary of A.G.A.'s comments and recommendations. These comments were prepared principally by Ronald D. Rudkin of the Southern California Gas Company and have been adopted by the A.G.A. Rate Reform Task Force.

I would first like to say however, that ICF's efforts to construct a model to accurately represent the impact of various rate designs on individual utilities is laudable but laden with tremendous difficulties which make such modeling efforts practically impossible. By necessity, such a model must oversimplify and incorporate assumptions on an industry-wide basis which simply do not hold true for individual gas distribution companies. Oversimplification is necessary to reduce the task of a rate design study to manageable proportions. Because of these necessary assumptions and oversimplifications, the usefulness of any model assessing a synthetic utility response to various rate designs is obviously limited. We believe the work done by ICF in the development of a model to test various rate designs and the individual and cumulative impact on the goals set forth in PURPA, was necessary in order to fulfill the mandates of the legislation. We firmly believe the work positively supports our conclusions heretofore stated.

SOME MAJOR DEFICIENCIES WITH THE ICF MODEL

- The static formulation used for the supply model fails to capture the consequences of prior period decisions.
- The supply model fails to adequately constrain many of the storage decisions.
- Use of the load duration curve distorts the true demand pattern and can adversely affect supply decisions.
- The demand model provides inadequate detail to accurately forecast consumption for the residential and commercial sectors.
- The price variable used in the model fails to provide an accurate assessment of the full impact of rate increases for most rate designs.
- The use of a constant price elasticity is difficult to justify when factors determining its value are expected to change in the future.

- The model fails to adequately capture the long-term consequences of price increases on gas consumption.
- The use of national conservation estimates to determine the reduction in consumption due to conservation for a specific utility is difficult to justify.
- With utilities being exposed to added financial risks, the assumption of a constant rate of return on rate base from year to year is unrealistic.

This completes the summary of specific comments on the model as prepared by Ron Rudkin of the Southern California Gas Company. However, to incorporate the full panoply of A.G.A.'s specific comments and recommendations on the interim model report, I offer the following comments taken from a letter dated November 30, 1979 addressed to Steve Skjei from Daniel Parson of Northern Illinois Gas Company. This letter is attached as Appendix B and is summarized as follows:

- In the generalized description of the transmission loop, there is no apparent recognition of the fact that state regulatory agencies could establish rates equivalent to the alternate price ceilings for incrementally priced customers. This would eliminate any MSAC reporting or surcharge passthrough to pipelines.
- In the supply sub-model of the distribution loop, is there any recognition of such factors as: (1) the influence of take-or-pay contracts; (2) the effect of securing long-term supply by pipeline supplier contracts as opposed to short-term interim purchases and, (3) the use of storage facilities as a substitute for interruptible service?
- In describing three primary methods of allocating costs, ICF must recognize that neither the number of customers nor customer costs is constant and that both will vary depending on the circumstances.
- With respect to assumed values used in the "constant elasticity demand curves" (Appendix A of the Interim Report), we are concerned that, lacking sufficient detailed analysis for support, these values are assumed to be based upon constant factors.

- In analysis of the residential heating market, the factor of replacing an old gas furnace with a new one does not necessarily affect demand.
- In all the rate forms utilized, there is apparently no recognition of the two-part rates which are in fact used in some areas for commercial and industrial loads.
- In the discussion of "declining block rates", commercial rates are set to have only one block. Inasmuch as declining blocks are applicable to both industrial and commercialized customers, setting commercial rates in only one block is a major oversimplification.

In conclusion, I would like to reemphasize the basic tenets of the gas utility industry position on the matter of the Gas Utility Rate Design Study.

- We believe that it is unnecessary and ill-advised to impose on the gas utility industry requirements similar to those contained in Title I of PURPA for the reasons set forth above.
- We believe further that specific rate designs should be left to the local and state regulatory commissions without the imposition of any federally-mandated guidelines or recommendations.
- However, in the event that federal guidelines and recommendations are set forth, we believe that DOE/ERA's sole responsibility is to evaluate the defined rate design standards in terms of (1) efficiency, (2) conservation, and (3) equity. Further, DOE/ERA must make a recommendation to Congress as to whether the PURPA-required study has identified certain standards that Congress should, as a matter of national policy and public interest, mandate the State and local regulatory agencies to consider for implementation. The vehicle for such consideration may be generic hearings to be held within their respective jurisdictions resulting in the adoption of such recommendations if found reasonable and applicable.

I believe that this fairly summarizes A.G.A.'s specific comments and recommendations. I thank you once again for the opportunity to set forth our views on this matter of extreme importance to the natural gas industry. If you have any questions, please feel free to ask me or any of the other panel members here today.

Dated: January 15, 1980

APPENDIX A

ERA Docket No. ERA-R-79-22A

CRITIQUE OF THE ICF GAS UTILITY MODEL

prepared by

Ronald D. Rudkin
Gas Requirements Forecasting Manager

Southern California Gas Company

on behalf of the

American Gas Association

January 10, 1980

CRITIQUE OF THE ICF GAS UTILITY MODEL1. Introductory Comments

This appendix provides a more detailed review and critique of the ICF Gas Utility Model. It is based upon documents mailed out by Dr. Stephen S. Skjei through October 16, 1979 to all participants in the Public Conference on August 8 and 9, 1979 regarding the Gas Utility Rate Design Study. A follow-up clarification report which was to be provided by ICF, Inc. was not available in time to consider it when preparing these comments. As a consequence, some of the points raised may not apply to what we understand is a more current version of the model.

In forming these comments, an attempt was made to assess whether the model could be used to accurately and completely assess the consequences of alternative rate designs for a specific utility. In our opinion, the ICF Model represents a good piece of research and may contribute to meeting the requirements of the PURPA legislation. In modeling something this complex, we recognize the necessity to make many simplifying assumptions. While these assumptions probably will not affect conclusions reached at the industry level, for reasons discussed in the third section, they will affect the accuracy of conclusions reached for a particular utility.

Moreover, we do not believe that that it is possible to draw any general conclusions from the study. Utilities are too diverse to attempt to characterize them by a set of prototypical or synthetic utility companies. Since many utilities already have more detailed versions of the ICF Models, the interest of all parties can best be served if each utility works with its state regulatory agency to analyze the consequences of alternative rate designs.

The remainder of the appendix is organized as follows. The next section provides an overview of the ICF Model. The third

section discusses specific criticisms of the model. The final section provides a summary and conclusions.

II. Overview of ICF Model

The ICF Model has two main sub-models:

- A. Transmission Model
- B. Distribution Model

A. Transmission Model

The Transmission Model determines purchased gas costs and surcharge amounts which reflect the incremental pricing provision of the NGPA. These costs are assigned to transmission and distribution companies respectively. The natural gas well data is divided into groups called tiers. Beginning with the tier with the smallest unit price, the various tiers are accumulated until the transmission company gas demand is satisfied. The cost of gas is calculated and assigned to general and surcharge accounts. All tiers priced above the threshold are included in the surcharge account. The surcharge account is assigned to distribution companies based on their non-exempt industrial load.

B. Distribution Model

1. Supply Model

The Supply Model is a static linear program (LP) which determines the least cost purchase, allocation, and storage policy. The supply model dispatches existing supplies, new supplies, and gas from storage to meet an annual load duration curve for firm customers. Supplies are selected to minimize costs with interruptible sales treated as a cost minimizing activity.

2. Rate Model

The Rate Model performs two functions. First, it determines aggregate revenue requirements in much the same way done in an actual rate proceeding. Second, it allocates revenue requirements to customer classes and rate blocks.

3. Demand Model

The Demand Model breaks consumption into four broad classes: Residential, Commercial, Firm Industrial, and Interruptible Industrial.

a) Residential Heating Demand

The number of gas heating customers is a function of gas heating customers from the previous year, plus new houses and houses replacing furnaces with gas. The fraction choosing gas is specified by a penetration equation which is a function of relative energy prices. The number of gas heating customers are then assigned to consumption blocks and to load segments (consumption periods throughout the year). Each load segment and consumption block has an average use per customer which is exogenously specified. For each forecast year, average use per customer for each block is modified by a constant marginal price elasticity.

b) Residential Non-Heating Demand

The number of customers is forecast yearly based on a time trend. Non-heating use per customer is determined by a marginal price elasticity.

c) Commercial Demand Model

The number of customers is forecast using a time trend. Use per customer is determined by a marginal price elasticity. The initial use per customer is exogenously specified. Annual demand is determined by multiplying the number of customers by use per customer.

d) Industrial Demand Model

The aggregate demand is separated into groups by alternate fuel. For each group, a step function is developed which expresses the number of customers on the system as a function of average gas price. An exogenously specified use per customer is then modi-

fied by a constant elasticity response function. Industrial demand is the product of the number of customers on the system and use per customer.

III. Major Deficiencies of the ICF Model

In the outline that follows, we've tried to highlight what is believed to be major deficiencies in the ICF Model. Because of its importance, most of the comments are focused on the distribution sub-model.

A. Supply Sub-Model

As previously mentioned, the Supply Sub-model uses a static, linear programming (LP) model which dispatches gas supplies to meet demand as defined by an annual load duration curve. The load duration curve is obtained by arranging the daily demand pattern into decending order of magnitude. Demands described by the load duration curve are then assumed to occur sequentially. There are several problems with this approach.

1. The optimization is done on a year by year basis. If demand and supply are not constant, a situation likely to be faced by most utilities in the future, this approach will produce incorrect (sub-optimal) decisions. Incorrect decisions result from the model's failure to reflect the effect of decisions made in one year (principally storage decisions) on supply availability in future years. This problem can be overcome by using a dynamic multi-year formulation with an explicit inventory equation to reflect year-to-year linkages as is usually done in traditional gas balance models.
2. A related problem with the period-by-period approach is that it does not provide a mechanism for determining the timing and need for additional storage facilities and/or the timing and need for supplemental supplies. Since rates affect current and future demands and thus the timing and need for storage and supplemental supplies it is clear that this deficiency must be rectified if the

model is to completely and accurately reflect the impact of rate designs on utility operations. This deficiency can be overcome by making these decisions part of the formulation.

3. The model does not properly constrain the amount withdrawn from storage. The model constrains the amount injected to be at least the amount extracted on an annual basis. It does not provide a similar constraint to insure that the amount extracted will not exceed the amount of gas in inventory for each period during the year as is done in traditional gas balance formulations. This defect can be rectified by imposing a constraint similar to the current annual constraint on a period-by-period basis.
4. The model does not include a constraint to guarantee that the amount injected will not exceed the storage capacity. This constraint may have been inadvertently omitted from the documentation.
5. If demands fluctuate greatly within the year and/or if the planning horizon is more than one year, use of a load duration curve will distort the timing of demand and thus adversely affect the storage, supply, and allocation decisions. This defect can be easily overcome by using the load curve as is done in most gas balance models.
6. Inventory holding cost for gas carried in storage from one period to the next is not considered in the linear program. This is probably because the ICF Model does not have explicit inventory equations. Failure to include inventory carrying costs will understate the total cost of storage as a source of future supply. This deficiency can be overcome by using a more traditional gas balance formulation which includes inventory balance equations in the constraint set and inventory holding cost terms in the objective function of the linear program.

B. Demand Sub-Model

It is clear the Demand Sub-model plays a crucial role in the analysis, since it determines the impact of rates on gas consumption. Unfortunately, this is probably the weakest part of the LCF analysis.

1. Residential Demand

The number of non-heating customers is based on a simple time trend. The number of non-heating customers depends on the number of existing non-heating customers, new construction, and factors which influence the saturation of gas appliances such as fuel costs, appliance costs, and income. To the extent that these factors differ from their historical trends, the non-heating forecast will be biased. This problem can be rectified by estimating a new equation which explicitly includes the above mentioned factors.

2. The same equation and thus the same penetration is used for houses replacing a non-gas furnace and for houses replacing a gas furnace. Obviously there are additional capital costs incurred when one replaces a non-gas furnace with a gas furnace. The model will tend to overestimate new customer growth from conversion to gas. This defect can be remedied by estimating separate equations.

3. The penetration equation is a linear function of fuel prices. Unless properly constrained, it can produce implausible results. That is, penetrations greater than one or less than zero. This defect can be overcome by using a more traditional multinomial logit formulation. This would give the equations a firm theoretical basis and would insure penetrations between zero and one.

4. Residential use per customer is given by an equation of the form:

$$D_j = \beta_j P_j^{-\alpha}$$

where:

D_j is the average consumption per customer in load segment j .

α is the constant price elasticity.

P_j is the real marginal rate in load segment j .

β_j is an exogenously specified constant for load segment j .

The equation fails to include income, number of people in the household, and other variables which economic theory and most empirical research have found to be significant factors in explaining consumption per customer. Failure to include these variables will have two consequences: First, price elasticities estimated from such an equation will be biased (most likely upward) because of the correlation between price and the omitted variables. Second, the price response will be overstated because price increases tend to be offset by increases in real income. This defect can be overcome by making this equation a function of the above mentioned variables.

5. The assumption of constant price elasticity is difficult to justify. The price elasticity for use per customer depends on appliance specific price elasticities (market share and utilization rate), market shares, and consumption rates. The constant price elasticity in the ICF use per customer equation implicitly incorporates these variables. To the extent that these variables change in the future the forecast will be biased. To overcome this deficiency, many utilities have developed detailed end-use models which forecast gas consumption at the appliance level.

These models include appliance utilization equations which are functions of such variables as price, income, number in the household, etc.

6. The model is too highly aggregated to correctly reflect residential consumption. The model makes no distinction between gas consumption for single-family dwellings, multi-family dwellings, and mobile homes. Gas consumption differs significantly between single-family dwellings, multi-family dwellings, and mobile homes. Further, appliance stock holdings, conservation retrofit potential, and price elasticities vary considerably by housing type. The model is incapable of reflecting changes in consumption due to changing housing patterns and can therefore be expected to give biased forecasts. To overcome this problem, many utilities have developed highly disaggregated models which forecast consumption by housing type and by appliance.
7. The use per customer equation is based solely on the real marginal block rate. As a consequence, customers are not responsive to changes in the customer charge and/or to changes in commodity charges for prior blocks. The ICF formulation will therefore inaccurately reflect the consequences of some of the alternative rate designs. This defect can be overcome by also including the cost of gas (fixed charge and commodity) for consumption up to, but not including, the marginal block in the estimation equation.
8. The treatment of conservation is too simplistic. Reduction in consumption due to conservation is gotten by "sharing down" national conservation estimates. These estimates are based on the estimated effect of federal building and appliance efficiency standards. Because significant differences exist between utilities concerning appliance saturations, current and future mix of

residential housing, current and future mix of commercial buildings, the age distribution of residential housing and commercial buildings, and the existence of more stringent state standards, such an approach will give biased results. To adequately model the impact of mandated standards, many utilities have developed detailed end-use models. These models describe gas consumption at the appliance and equipment stock level. This kind of detail is required to reflect the effect of efficiency standards for new and replacement equipment.

9. The demand models for the residential and commercial sectors fail to consider the full impact of price increases. Price increases have three effects. In the short-run, price increases decrease the utilization of gas consuming appliances (utilization response). In the long-run, price increases cause a switching to appliances and equipment using other fuels (market share response) and the manufacture of more efficient appliances and equipment (efficiency response). Only the utilization response and the market share response are considered in the residential heating sub-model. For the residential non-heating sub-model and the commercial sub-model, only the short-term utilization response is modeled. As a result, the long-term consequences of rate designs are not adequately captured. Many utilities are currently using dynamic econometric models to capture both the long-term and short-term responses to price increases. Some utilities use end-use models (appliance stock level models) with marginal saturation rate equations which depend on equipment costs, equipment efficiencies, and fuel costs to model market share responses.
10. The single equation used in the ICF Model to describe use per customer in the commercial sector is not capable of representing changes in the mix of commercial establishments. Restaurants and warehouses have very different energy intensities. If building

types grow at different rates in the future than in the past, the ICF forecast will be biased. To provide sufficient detail for accurate forecasting, many utilities and some state agencies are using end-use commercial models which forecast by building type and end-use.

C. Rate Design Sub-Model

The model assumes a constant return on rate base. Utilities may have different equity structures over time. Further, utilities are developing into energy companies, undertaking their own supply exploration programs and incurring the associated additional financial risks. It is highly unrealistic to assume that rate of return is constant from year to year. This assumption will tend to understate revenue requirements.

IV. Summary and Conclusions

We believe that the ICF study is a good piece of research concerning the impact of alternative rate design policies on natural gas transmission and distribution companies and may contribute to meeting the requirements of the PURPA legislation. While conclusions reached by the model may be valid at the industry level, because of the deficiencies discussed in the third section of the paper and summarized below, the capabilities of the model are not such that it can be used to determine the consequences of alternative rate designs for a specific utility.

Some Major Deficiencies of the ICF Model include:

1. The static formulation used for the supply model fails to capture the consequences of prior period decisions.
2. The supply model fails to adequately constrain many of the storage decisions.
3. Use of the load duration curve distorts the true demand pattern and can adversely affect supply decisions.
4. The demand model provides inadequate detail to accurately forecast consumption for the residential and commercial sectors.
5. The price variable used in the model fails to provide an accurate assessment of the full impact of rate increases for most rate designs.
6. The use of a constant price elasticity is difficult to justify when factors determining its value are expected to change in the future.

7. The model fails to adequately capture the long-term consequences of price increases on gas consumption.
8. The use of National conservation estimates to determine the reduction in consumption due to conservation for a specific utility is difficult to justify.
9. With utilities being exposed to added financial risks, the assumption of a constant rate of return on rate base from year to year is unrealistic.

The individual utility and its state regulatory agency are best equipped to determine the consequences of alternative rate designs and the most appropriate rate design for a given customer class and within a specific service area.

NORTHERN ILLINOIS GAS

One of the NICOR
Basic Energy Companies

P.O. Box 190 Aurora, Illinois 60507 Phone 312 355 8000

November 30, 1979

794239

Mr. Stephen S. Skjei
Chief, Regulatory Support
and Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Skjei:

I have your letter of October 16 enclosing the fourth interim report on the gas utility rate design study prepared by ICF Incorporated. I believe I have previously sent you my comments with respect to the first three reports. Let me offer the following thoughts and ideas with respect to the fourth report.

- A. On pages 3 and 5 a generalized description of the transmission loop is provided. It apparently assumes that distribution companies will report to their pipeline suppliers MSAC's attributable to incremental pricing which will impact pipeline PGA's affecting exempt customers. I fail to see any recognition, which is essential, of situations in which state regulatory agencies establish rates for non-exempt customers served by distribution utilities, equivalent to the alternate price ceilings, thereby eliminating any MSAC reporting or surcharges flowing to the pipelines.
- B. I assume that in a distribution company loop that the supply module will recognize a number of complexities, such as the influence of take or pay conditions in supplier contracts, the relative long-term advantages or disadvantages of increasing takes under contracts with pipeline suppliers as opposed to short-term emergency or interim purchases,

the flexibility of taking additional gas over and above immediate customer requirements to improve supply conditions in the future where adequate storage capacity exists, and the use of storage facilities as a substitute for interruptible service.

- C. On page 8 the three primary methods of allocating costs are briefly described; it must be recognized that number of customers is not a constant value, but that customer costs will differ between different classes of service because of different sizes of service, meters and other facilities. In addition, for companies with substantial storage facilities the peak month (or some major portion) may be equally valid as is the peak day as an allocation method for demand costs.
- D. In Appendix A certain values are assumed for different classes of service with respect to "constant elasticity demand curves". Measurement of elasticity of demand is extraordinarily complex as we have discovered in studies which we have been conducting for our own service area. Furthermore such measurements have significant impact upon customer usage and the extent to which customer conservation occurs. In the residential area particularly there may well be qualitative (psychological) factors involved in addition to quantitative. I am somewhat concerned about using assumed constant factors without sufficient detailed analysis to determine the validity or reasonableness of such factors, because of the significant impact on demand which results.
- E. In the residential heating market (page 9) one of the factors mentioned is "replace an old gas heated furnace with a new gas furnace". Except to the extent that the replacement is a more efficient furnace, thereby reducing demand, this factor should not measurably influence demand for gas.
- F. With respect to rate forms I see no recognition of two-part rates which are used in some areas for commercial and industrial loads and which may have future applicability to residential loads. Furthermore table III-1 assumes that only some portion of the customer cost should be recovered.

from the customer charge; we are currently experimenting, and perhaps some other companies are also evaluating, the desirability and feasibility of recovering not only customer costs but also demand costs through some form of fixed monthly charge. Clearly the advantage of such an approach is that the residual (commodity) cost represents almost exclusively the cost of gas and the need for blocks in the rate schedule is thereby eliminated because the commodity charge is a constant unit cost.

- G. On page 13 (declining block rates) the assumption is made that commercial rates will have only one block. This is a major oversimplification; if blocking is reasonable for industrial it is equally reasonable for commercial. It also appears in this same section that the assumption is made that demand costs are imposed by heating loads and that the first residential block is established "to capture most of the non-heating load". It must be recognized that non-heating load in the wintertime is superimposed on heating requirements and does indeed contribute to demand cost components. I would further hope that submodels might be available under which the number of blocks, and the method of designing them, could be varied from the philosophy set forth on page 13.

To the extent that the entire study attempts to evaluate alternative rate designs based solely on quantifiable data in a model, the effort may well be subject to significant shortcomings. There are substantial differences between states or regions of the country in terms of economic activity, types of industries, political considerations, and other factors which may at least partially override results from quantifiable and objective facts. I have no suggestions for how this problem can be handled other than to recognize its existence and provide words of caution in any reports which issue based on this study.

I appreciate the opportunity of commenting. Please continue to keep me informed of progress on this job, and feel free to raise any additional questions or request additional assistance.

Sincerely yours,

Daniel Parson
Assistant Vice President

DP/dak

COMMENTS
ON
"INTERIM REPORT ON SIMULATION OF
SEVEN RATE FORMS"

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

ECONOMIC REGULATORY ADMINISTRATION

792201A

Gas Utility Rate)
Design Study)

Docket No. ERA-R-79-22

WRITTEN COMMENTS OF THE AMERICAN GAS ASSOCIATION ON THE
FIFTH INTERIM REPORT FOR THE GAS UTILITY RATE DESIGN STUDY

The following written comments are provided by the American Gas Association on behalf of its 300 member natural gas transmission and distribution companies on the fifth interim report for the gas utility rate design study. The Economic Regulatory Administration (ERA) distributed the fifth interim report for this study on January 11, 1980. Written comments were requested by January 30, 1980. A.G.A. respectfully requests the opportunity to file these written comments out of time because of the exigencies associated with completing review of the report by interested member companies within the initial time constraints imposed by ERA.

Introduction

The written comments of the American Gas Association are divided into three parts: one, dealing with the need for full public review of the draft final report on this study; second, formal responses to the five major policy questions posed by ERA regarding the fifth interim report; and third, detailed technical comments on the fifth interim report provided as an appendix to these comments.

There is a Need for Full Public Review of the Draft Gas Rate Design Study

The formal public comment process regarding the development of the gas rate design study has so far solely focused on the

computer model being prepared by ICF Incorporated which will serve as the basis for developing the documentation for the final study results. At the most recent public conference on the study, ERA distributed for review an outline of the gas rate design report to Congress pursuant to Section 306 of PURPA. However, there have been limited opportunities for review and comment on many of the issues raised in the draft outline.

In light of these developments and in full recognition of the Section 306 (d) public comment and participation requirement, A.G.A. strongly supports the establishment of an early opportunity for public review and comment of the completed draft study and supporting documentation before it is ultimately submitted to the Congress. It is at this stage in the process that valuable contributions can be made regarding the complete draft study, rather than just the narrow ICF model documentation, which is a small portion of the total study project. Otherwise, full public participation in the conducting of the study cannot be achieved unless full disclosure of all operative features and components of the study are made available prior to finalization by May 9, 1980. It is only this type of approach that would satisfy the Section 306(d) public participation requirements under the Act.

Formal Responses to ERA Questions

A.G.A. respectfully submits the following responses to the five questions posed in the memorandum to all interested parties on issues in the ICF Report.

1. Are the rate structures and levels for each rate form as simulated appropriate and reasonable?

It is extremely difficult to provide a positive response to this question when fully recognizing that none of the simu-

lated distribution company runs specifically match the operational characteristics of individual A.G.A. distribution company members. Further, the restrictive method of calculating differential rate levels between blocks, for those rates which are blocked, provides problems which are addressed in the comments contained in the Appendix. While we recognize that some assumptions are necessary regarding cost components to be recovered in each block, greater flexibility should be provided and would be more desirable.

2. Do the supply scenarios capture an appropriate range of future supply costs?

The alternative supply scenarios appear to cover an appropriate range of circumstances. However, their impact is constrained by assumptions regarding future oil prices, and by a lack of information regarding pipeline rate design, curtailments, and other associated factors which preclude making a formal final judgment on this question.

3. Are customer class price responses reasonable?

A.G.A. member companies have significant problems in responding to whether customer price responses are reasonable, particularly in view of the acknowledgement on I-1 that further work will be undertaken concerning industrial conservation and fuel switching decisions and residential demand response to price changes. However, with respect to industrial response, it appears that EEP has assumed that this would be triggered when gas costs exceed the level of alternate fuel prices. We would respectfully note that with respect to this incremental pricing assumption, there is a strong likelihood that fuel switching would occur at a lesser level of gas costs because of the desire of industrial customers to avoid the substantial regulatory burdens and uncertainty imposed by the incremental pricing requirements of the NGPA.

4. Are the characteristics of the simulated distribution companies reasonable and appropriate?

A.G.A. strongly believes that three simulated distribution companies cannot cover anything like the range of conditions and characteristics which exist throughout the nation. If the study is to evaluate alternative rate designs on a national basis, then substantially more cases are required. This is exemplified by the magnitude of divergence between case A results compared to cases B and C. In this regard, the gas rate design study should specifically recognize the inherent limitations fostered by use of three simulated distribution company circumstances as the basis for conducting the gas rate design study itself. The ultimate report and its conclusions could not incorporate the unique factors associated with all gas distribution systems. A.G.A. respectfully suggests that a disclaimer should be included prominently in the final report to effectively recognize this concern.

5. Which additional rate forms should be examined?

While A.G.A. believes that a sufficient number of rate forms has been examined in the study, some variations in the philosophy of determining block differential charges would be appropriate.

Conclusion

For the foregoing reasons, A.G.A. respectfully requests that the recommendations in these comments be considered for incorporation in the substantive and procedural development of the final gas rate design study under Section 306 of PURPA. A.G.A. member companies, and specifically the members of the A.G.A. Rate Reform

Task Force, stand ready to assist the ERA during the process of developing this final study.

Respectfully submitted,

AMERICAN GAS ASSOCIATION

by

George H. Lawrence
President

Michael J. Zimmer
Staff Vice President
Government Relations

Communications with respect to these comments should be addressed to:

Thomas C. Martin
Research Assistant
Legislative & Regulatory
Affairs Division
American Gas Association
1515 Wilson Boulevard
Arlington, VA 22209
(703/841-8465)

Dated: February 8, 1980

APPENDIX

TECHNICAL COMMENTS OF THE AMERICAN GAS ASSOCIATIONGeneral Comments

- a. It is apparent that much of the information in the report may well be modified subsequently because of further research on the items specified on page I-1 (better information about industrial conservation and fuel switching, assumptions concerning residential demand response to price changes, and alternative assumptions about the price and availability of supplies). In spite of tight time schedules, we would appreciate receiving another version of this at such time as modifications are completed to reflect these and other inputs.
- b. It is not clear whether, where a particular rate form implies industrial load losses, an iterative procedure has been used to reassign the fixed cost recovery previously achieved by those industrial sales to the remaining sales to other categories of users. In some cases this may require more than one reevaluation, and without such a procedure the rate levels for residential, commercial and remaining industrial (if any) will be understated.
- c. There is implicit throughout the entire report an assumption that customer reactions are highly influenced by the charge in the last block of their usage (where blocked rates are employed). It is our firm belief, particularly in the residential and small commercial area, that the overwhelming preponderance of customers are influenced solely by the size of their total bill (rather than the terminal block charge applicable to them) to either conserve or switch.
- d. All of the cases studied reflect some industrial interruptible load as a characteristic of the utility analyzed. There are some companies, with substantial underground storage capabilities, where interruptible sales are not made to any customer and where storage serves as a load balancing alternative.

Specific Comments

1. In both Tables II-2 and II-3 declines are shown for customer charges between 1979 and 1990. We do not believe it is possible in the real world for customer charges (defined in your study to cover the customer cost component) to decline in a world in which cost inflation at some level is implicit in the economy.

2. On page II-8 there is a discussion about a pool of potential industrial customers and about changes in number of industrial customers. With the improved gas supply picture in the last year or two, the magnitude of any pool of potential customers has declined very materially, and is probably nonexistent for many companies. Furthermore numbers of industrial customers are not a meaningful concept, only the total load served to industry.
3. On page II-14 (and page III-10) statements are made that residential load factor improves as large customers conserve more. This is absolutely wrong. Consider a situation where thermostats are set at 72°. At zero temperature the gain in heat required is 72, and at 40° temperature the gain is 32, a ratio of 2.25. If the thermostat is set at 66° the comparable gains are 66 and 26, a ratio of 2.54. Conservation worsens residential load factors which is consistent with industry knowledge that heating load factors are poorer in southern areas with fewer seasonal degree days than there are in northern areas.

In their comments on changes in load factor caused by the various rate designs, ICF assumes that conservation will improve load factors. This results by assuming that demand and energy price elasticities are equal. While there are few, if any, good studies that look at the peak demand price elasticity of gas use, we believe that this demand price elasticity is less than the energy price elasticity. While it is true that price increases may cause customers to turn back their thermostats and thus use less gas during a month, on that 100°F peak day, furnaces will be running pretty much full time regardless of the temperature setting. A needle peak could then develop that would actually lower the utility's load factor.

4. The last paragraph on page II-17 is extremely confusing. Clearly in situations where industrial load losses occur, the proportion of distribution costs absorbed by residential and commercial customers must increase any allocation method.
5. On page III-1 there is a description of the method of cost assignment to the various blocks of inverted rates. It is of course completely illogical to cover all volume costs in the first step since the amount of such volume costs will depend upon whether the customer uses the follow-on steps. Recovery of customer and demand costs in follow-on blocks is in complete violence with the principles of cost causation and recovery. These defects are sufficiently major to require a complete revision of all of the material related to inverted rates.
6. At various points in the report (for instance on page III-6) there are allusions to "reallocation of additional costs to the industrial class." Wherever such a procedure has been

followed it should be emphasized that such reallocations of costs may well be arbitrary and unjustified; while costs are not always precisely measurable the cost responsibilities imposed on a distribution system by various customer categories cannot be "reallocated" in the real world.

7. With respect to page III-13, the statement that cost allocations are all directly proportional to volumes served under volumetrical rates, is correct. It might be appropriate to emphasize that this is a basic defect of volumetric rates since they therefore ignore completely customer demand and cost components which differ between customer categories.
8. We agree with your assumptions regarding incremental pricing set forth on page IV-1 because these are the current conditions. We know you are fully aware of the possibilities of major changes in the ways in which incremental pricing is implemented in the near term future.
9. On page IV-13 there is a discussion of demand response differences under incremental pricing (as opposed to the base case). As industrial customers switch, more costs must be recovered from residential and commercial, this in turn causes some customers in those categories to terminate their use of gas placing an ever increasing burden on those who remain. The point is that the ability to market gas at a given price at the local distribution level is an essential input to pipeline decisions to purchase gas, and forms a constraint upon future supply levels and prices.
10. The future gas supply scenario used by ICF is still unclear. This will have a significant impact especially on their incremental pricing study. An earlier report stated that ICF was assuming a declining availability of gas. They indicated they were going to change this to a slightly increasing supply, but we have not seen anything to assure that they have changed this assumption.
11. Another problem that has not been adequately addressed is the effect of an Even Monthly Payment Plan (EMPP). Changes in rate design would not affect the monthly payments and therefore would probably have little effect on gas use. More and more customers are availing themselves of this plan in order to better budget their increasing gas bills and, eliminating the EMPP would cause a considerable stir.

2/8/80

UNITED STATES OF AMERICA
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

792202A

In the Matter of
Gas Utility Rate Design Study) Docket No. ERA-R-79-22A
Required By The Public Utility)
Regulatory Policies Act of 1978)

COMMENTS OF ALABAMA GAS CORPORATION

Pursuant to the Memorandum for All Interested Parties dated January 11, 1980, from Stephen S. Skjei, Chief, Regulatory Support and Analysis Branch, Division of Regulatory Assistance, Office of Utility Systems, Economic Regulatory Administration (ERA), in the above-captioned docket, Alabama Gas Corporation (Alabama Gas) shows as follows:

I.

Alabama Gas is a corporation organized and existing under the laws of the State of Alabama with its principal office in Birmingham, Alabama. Alabama Gas is a public utility subject to the jurisdiction of the Alabama Public Service Commission. It purchases most of its natural gas for resale from Southern Natural Gas Company (Southern) at various delivery points in the State of Alabama for distribution and resale in and in the vicinity of one hundred and forty-nine municipalities or communities in the State of Alabama, including Birmingham, Montgomery, Anniston, Tuscaloosa and Selma.

II.

All correspondence and communications regarding this position.

are to be addressed to the following:

A. S. Lacy, Vice President-Secretary
G. G. Turner, Manager, Rates & Regulations
Alabama Gas Corporation
1918 First Avenue North
Birmingham, Alabama 35295

III.

The Memorandum for All Interested Parties dated January 11, 1980, invites comments on the Fifth Interim Report for the Gas Utility Rate Design Study. Although the ERA Memorandum asks five specific questions for review or comment, Alabama Gas submits two basic comments concerning the overall report:

- (1) The results of the report must be heavily qualified as to its relevance to any single distribution company's rates
- and (2) The report must consider the full impact of both Phase I and Phase II of Incremental Pricing under Title II of the Natural Gas Policy Act of 1978.

The Final Report Must Be Heavily Qualified

The Fifth Interim Report for the Gas Utility Rate Design Study selects three hypothetical gas distribution companies in three different areas of the United States with three different supply scenarios and three different sales matrices. The results of the study can only represent impacts on the three models chosen. Because of the many variables involved in the model, the results of the study must necessarily be stated in impact ranges rather than specific effects. The model completely ignores two sections of the country, the Northwest and the Southeast. However, even if model companies for these two areas are studied, significant gaps in results would remain.

There are a multitude of variables which have varying effects

on each natural gas distributor in the country. The following is a list of some of the variables, each of which can have a wide range of impact on one company versus another:

- Take or Pay Balances
- Storage Capabilities & Usage
- Elasticity of Demand Curves
- Weather
- Budget Payment Plans
- Sales Matrix Sources
- Prices and Levels of Supply
- Incremental Pricing
- Peak Shaving Capabilities
- Alternate Fuel Prices
- Cost of Service Studies
- Load Factors

With so many variables and others not listed, it is doubtful that the study can accurately define the ranges of effects on all gas distributor systems of various rate design recommendations. The final study presented to Congress, therefore, should be heavily qualified and should state that optimum rate structures can not be recommended by ERA on a nation-wide basis.

The Report Must Consider Full Impact of Both Phase I and Phase II of Incremental Pricing

The Fifth Interim Report for the Gas Utility Rate Design Study does not demonstrate the effects of Incremental Pricing. A study of the effects of Incremental Pricing is, of course, required by Section 306 of the Public Utility Regulatory Policies Act of 1978. The impact of Phase I of Incremental Pricing will be relatively insignificant compared to that of Phase II.

Initial studies of Phase II Impacts by Alabama Gas Corporation show that shifts of thirty (30) percent of the company's revenues from exempt uses of natural gas to non-exempt uses may occur.

The aggregate effect to the Alabama Gas non-exempt industrial customers will be staggering. Rates to non-exempt customers will double rapidly. Exempt users will see their rates substantially reduced. The differential between exempt customer rates and non-exempt rates will be as much as \$4.60 per MMBtu.

Assuming the current local price of \$6.00 per MMBtu for No. 2 fuel oil and assuming that the total amount of acquisition costs that will be required to be passed through by Alabama Gas' pipeline supplier will increase Alabama Gas' rates to its non-exempt industrial customers up to the ceiling price of No. 2 fuel oil, Alabama Gas estimates that the Phase II incremental pricing regulations as promulgated would result in a gas cost increase to these industrial customers of Alabama Gas of over \$87 million per year, 30% of the Company's revenue. This increase in revenues to Alabama Gas of over \$87 million must be passed on to its exempt customers, primarily residential customers. The net effect of a reduction in rates of this magnitude will be to reduce the Alabama Gas rates to its exempt customers to a level much below its average cost of gas. Thus any incentive on the part of the exempt customer to conserve gas would largely disappear.

Extreme shifts in revenue responsibility will occur nation-wide as a result of Phase II of Incremental Pricing. The turmoil caused by incremental pricing is a perfect example of the result of the imposition of a nation-wide rate standard. Alabama Gas urges ERA to consider deeply and report thoroughly to Congress, the wide distortions in rate levels which will

occur if Phase II is allowed to go into effect. Because of these possible effects, the ERA study will be meaningless without an in depth study of incremental pricing!

Conclusions

Alabama Gas submits that: (1) the ERA report to Congress must be made in ranges of results and the conclusions must be heavily qualified to the extent that the full effect of the items directed by Congress to be studied cannot possibly be determined through nation-wide models; therefore, ERA should recommend to Congress that no nation-wide rate standard is appropriate for the gas industry; and, (2) the ERA report should point out that Congress needs to give particular attention to the drastic effects of Phase II of Incremental Pricing.

Respectfully submitted,

G. G. Turner, Manager
Rates & Regulations

ALABAMA GAS CORPORATION

ORIGINAL

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

before the

792203A

Economic Regulatory Administration

Gas Utility Rate Design Study) Docket No. ERA-R-79-22

COMMENTS OF
ASSOCIATED GAS DISTRIBUTORS
ON FIFTH INTERIM REPORT FOR THE
GAS UTILITY RATE DESIGN STUDY

On January 11, 1980, the Economic Regulatory Administration (ERA) distributed the fifth interim report for the gas utility rate design study. Written comments were requested on the report and study by January 30, 1980. Accordingly, the Associated Gas Distributors (AGD) */ respectfully submits the following comments:

The Section 306 Study

Throughout ERA's development of the gas utility rate design study required by Section 306 of the Public Utility Regulatory Policies Act of 1978 (PURPA), the focus of public participation has been on a computer econometric model being prepared by ICF Incorporated. Both public conferences held by ERA concerned interim

*/ A list of the AGD member companies is attached hereto as Appendix A.

status reports by ICF on its modelling efforts. Various documents were presented and comments solicited on them.

At the last public conference, ERA distributed a draft outline of the gas rate design report to Congress. It is clear that the ICF model is but a part of the ultimate study which ERA will produce pursuant to Section 306. Indeed, a very substantial portion of the draft outline concerns matters which have not been exposed to public scrutiny and comment. In fact, the only aspect of that outline upon which there has been general public review and comment has been the ICF report -- parts III. A, B and C of the outline at best. Further, it now appears that ERA intends to proceed rather quickly to complete its report to Congress. In view of these circumstances and the Section 306 public consultation and comment requirements, AGD submits that it is imperative for ERA to seek early public review and comment on the complete study and supporting documentation prior to its submission to Congress. Also, since the ERA report to Congress is intended to include material beyond the ICF analysis, it would be appropriate to discuss other available rate design studies, such as the Zinder Report.

If, as stated at the public conferences earlier this month, the study is circulated for "internal DOE" review on March 1, there is no sound reason for not also distributing it to the public at large at that same time. Obviously, the "draft" nature of the study would be apparent. But, this is precisely the stage at

which meaningful contributions can be made on methodologies used and conclusions reached in the study. Meaningful "public participation in the conduct of the study" */ simply cannot be achieved through something less than full disclosure of all aspects of it at a reasonable time prior to completion. In this regard, ERA would be well-advised to review the procedure used by the Federal Energy Regulatory Commission (FERC) to develop its regulations on incremental pricing. There, without a specific statutory directive for public consultation, the FERC employed a genuinely open process which provided substantive as well as procedural recognition of the views of all interested parties. AGD is prepared to assist in any similar effort here and to meet any reasonable schedule for comments which ERA provides.

Finally, at this time it is neither necessary nor appropriate for ERA to draw conclusions with respect to "implementation" of the section 306 study. There is, for instance, no basis to conclude from the materials presented to date that a PURPA Title I-type program for electric utilities is warranted for gas utilities. No congressional mandate requires such a program and to conclude so at this stage would frankly exhibit a predisposition fundamentally at odds with the bifurcated approach Congress designed into Section 306. It may well be that the highest and best use of

*/ § 306(d) Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat 3153.

the Section 306 study may ultimately be as simply another reference tool. The point is that the study should not constrict or prejudice the range of recommendations which may evolve as ERA proceeds to fulfill its complete Section 306 responsibilities.

The ICF Interim Report

Though the ICF modelling effort is improving, AGD remains seriously concerned with the very limited number of "prototype" distributors to which the several rate structures are applied. Apparently, this problem will not be resolved in the final ICF work product. The reasons given for not including a much larger sampling of distributors are essentially logistic -- the modeling effort becomes unmanageable and cannot be completed in a timely fashion. We are told, however, that numerous variables are utilized to permit a broad range of diversity among the chosen prototype companies. Unfortunately these reasons and rationales, as factual as they may be, do not resolve AGD's concern.

As a practical matter, the conclusions reached in the report will lend themselves to being adopted in some quarters as "gospel" -- the definitive "answer." That is, of course, not true. While ICF's model may have the capacity to exhibit a broad range of diversity among distributors, it is highly unlikely that the final report will in fact use all of these variables and combinations thereof in a readily understandable manner to describe

or predict the impact of a particular rate design on a particular gas distributor. Nonetheless, the tendency is to extrapolate what appears "good" for a prototype distributor in a computer model to what should be good for a specific distributor in the real world.

Since ICF and ERA are unwilling to substantially expand the number of prototype distributors, AGD strongly urges ERA to recognize and state candidly the limitations of the report. A caveat of the boldest type should be developed at the outset of the report. The limited scope of diversity should be forthrightly stated and any conclusions reached should be repeatedly accompanied by language to the effect that such conclusions are valid only to the extent that the variables and distributors assumed are in fact accurate and that the mechanics of the model reflect real world distribution company operations. The report and its conclusions simply cannot embody the uniqueness of all gas distribution systems and should so concede. In fact, the ICF model does not illustrate the actual operations of any particular gas distribution company. Accordingly, AGD respectfully suggests that a "disclaimer" to this effect be prominently affixed throughout the report. A reasonable disclaimer would state: "The conclusions reached herein are premised upon a multiplicity of assumed variables and do not necessarily reflect actual operating conditions of any particular natural gas distribution company."

The remaining comments herein are directed to specific points in the interim report which, in AGD's view, should be corrected or clarified in the subsequent report. These include:

1. The model's elasticity factors are among the most crucial information inputs. The elasticity factors directly affect quantity of gas consumed and, thereby, indirectly affect the number of customers, typical bills, and average rates -- all categories being used to evaluate the various rate forms. The model uses elasticity factors derived from nationwide data, though the precise methods used to determine them are not explained. The model also uses average rates and annual degree days in formulating a demand response and assumes customers respond to marginal price increases. In reality, elasticity factors vary by utility and are a function of rates charged, annual income per customer, what part of the customer's budget is being spent on gas usage, whether the customer reacts to marginal or average prices, etc. Elasticity adjustments for Distributors A, B, and C will be over- or under-stated depending upon how their elasticity factors compare to those used in the model. The elasticity factors in the model operate on increases in marginal prices which tends to maximize the amount of "conservation" for those rate structures where most

of the increase goes into the marginal block (such as inverted rates). This elasticity adjustment is based on the theory that customers react to the marginal price. Thus, if the study were done using average prices instead of marginal prices, it would show almost identical demands for all rate forms. This is due to the fact that the revenue requirement is the same for all rate forms and produce about the same average price. The point is that the importance of the elasticity adjustments is substantial. Accordingly, the report should explain with specificity the assumptions made in relation to elasticities as well as any limitations.

2. The 10 percent "swing" from warmest to coldest weather temperatures which was retained from the prior interim report should be revised. Ten percent is unrealistically low and, in any event, the weather variation should be based upon the probability of a given weather level occurring.
3. Gas supply assumptions should be described in detail. The last report was premised on a constrained supply scenario exhibiting supply decreases through the year 2000. That scenario is inconsistent with AGD member company projections as well as those of the Gas Research Institute, the Administration's National

Energy Plan II and the Stitt/Blaydon, Natural Gas Supply and Curtailment Report as presented to The Energy Bureau (1979). ICF advised at the public conference that a different supply scenario is now being used, but details were not provided.

4. It is incorrect to assume that all distribution company customers of a given interstate pipeline have equal surcharge absorption capabilities for purposes of incremental pricing.
5. The assumption of perfect economic dispatch is unrealistic and should be changed. A probability of risk analysis technique should be applied here to reflect more accurately actual operating conditions wherein a distributor dispatches in the winter its supplies on the assumption that the remainder of the year would be a design coldest season.
6. The method for factoring "take or pay" and minimum take" provisions in contracts between distributors, interstate pipelines and other supply sources into the report should be described in detail.
7. An explanation of how the model deals with curtailment would be useful and appropriate. Specifically, the model must test the sensitivity of interacting the transmission loop with the distribution loop un-

der various curtailment plans in effect on interstate pipeline systems.

8. Tables II-4 and 5 indicate that the number of interruptible customers and volumes sent out to interruptible customers increase while firm industrial and residential load decrease. This situation does not appear to recognize the strict price relationship between interruptible customers and alternate fuel prices. If the model does recognize this relationship, then it is inconsistent to exhibit, as the report does, a decrease in interruptible load in the incremental pricing discussion. This should be clarified.
9. Actual operating experience indicates that residential load factors do not necessarily improve with conservation as the report shows. Peak day requirements may well be influenced by such factors as distress heating.
10. The report appears to have assessed alternative fuels to the customer in terms of price, but an assessment in terms of regional supply availability is absent and should be detailed. This regional supply assessment must also recognize national and world-wide supply constraints, including institutional constraints.
11. The report does not consider the impact that budget billing, a prevalent practice, exerts on each of the rate designs studied.

12. The model output should be tested against conditions present on an actual utility systems, and these tests and results should be disclosed. There is, for example, no indication that the demand module and assumptions underlying it have been so validated. Validation of this and other elements of the model should be performed.
13. The model uses rates of return by class and the relationship of the class rate of return to total company (unitized rates of return) to set "fair" revenue requirements. The latter relationship is to simulate regulatory evaluation of items such as value of service, cost methodology differences, etc. The model does not, however, provide any guidance as to intra-class rate design. Inverted rates or flat rates without a customer charge may produce lower demands but may also distort the rates of return of large customers versus small customers. Flat rates without a customer charge could lead to revenue requirement instability if small customers are hooked-up in large, urbanized areas, where distribution networks are very expensive to build and to maintain. (See page II-4 of Interim Report.) The model contains no measure

(such as rates of return by size of customer) to evaluate "fairness" within a rate class.

ERA Questions For Reviewer Comment

In the January 11, 1980, "Memorandum to All Interested Parties" several questions were posed concerning issues in the ICF report. Generally, AGD is constrained to respond in the negative to the first four questions based upon the comments stated above. Specifically, our responses are as follows:

1. Are the rate structures and levels for each rate form as simulated appropriate and reasonable?

We are not aware of any AGD member company which "matches" the simulated distributors. Further, we are not able to judge either the appropriateness or reasonableness of the rate structures and levels for each rate form even as to the simulated distributors because of numerous unknown factors and assumptions.

2. Do the supply scenarios capture an appropriate range of future supply costs?

ERA and ICF have not provided sufficiently detailed supply scenarios to permit an accurate answer to this question. Such items as pipeline rate design, curtailment and other factors must be disclosed before this assessment can be made.

3. Are customer class price responses reasonable?

These responses do not appear reasonable in terms of residential conservation, residential load factors or interruptible customer demand as discussed above. Further, the responses do not appear reasonable for any specific gas distribution company.

4. Are the characteristics of the simulated distributors reasonable and appropriate?

As to the simulated distributors, the characteristics may be reasonable and appropriate. As to an individual distribution company or as descriptive of distributors across the nation, the characteristics do not appear reasonable or appropriate.

5. Which additional rate forms should be examined?

The impact of various interstate pipeline rate designs should be assessed as to their impact on local distribution company rates.

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AGD appreciates this opportunity to comment on the ICF interim report and gas rate design study and looks forward to further work on this important study.

Respectfully submitted,

ASSOCIATED GAS DISTRIBUTORS

By
Frederick Moring
 Dana Contratto

Crowell & Moring
 1100 Connecticut Avenue, N.W.
 Washington, D.C. 20036

January 30, 1980

ASSOCIATED GAS DISTRIBUTORS

Baltimore Gas & Electric Company
Bay State Gas Company
The Berkshire Gas Company
Boston Gas Company
Bristol & Warren Gas Company
The Brooklyn Union Gas Company
Cape Cod Gas Company
Central Hudson Gas & Electric Corporation
Chesapeake Utilities Corporation
City of Holyoke, Mass, Gas & Electric Dept.
City of Westfield Gas & Electric Light Dept.
Commonwealth Gas Company
Concord Natural Gas Corporation
The Connecticut Gas Company
Consolidated Edison Company of New York, Inc.
Delmarva Power & Light Company
Elizabethtown Gas Company
Fall River Gas Company
Fitchburg Gas & Electric Light Company
Gas Service, Inc.
Haverhill Gas Company
Long Island Lighting Company
Lowell Gas Company
Lynchburg Gas Company
Manchester Gas Company
New Bedford Gas & Edison Light Company
New Jersey Natural Gas Company
New York State Electric & Gas Corporation
Northern Utilities, Inc.
The Pequot Gas Company
Philadelphia Electric Company
Philadelphia Gas Works
Providence Gas Company
Public Service Company of North Carolina, Inc.
Public Service Electric & Gas Company
South County Gas Company
South Jersey Gas Company
The Southern Connecticut Gas Company
Tiverton Gas Company
UGI Corporation
Valley Gas Company
Washington Gas Light Company

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ROBERT ABRAMS
Attorney General

February 5, 1980

Stephen S. Skjei
Chief, Regulatory Support
and Analysis Branch
Division of Utility Systems
Economic Regulatory Administration
U.S. Department of Energy
2000 M Street N.W.
Washington, D.C.

Dear Mr. Skjei:

Enclosed please find "COMMENTS ON ICF GAS RATE
DESIGNS STUDY-INTERIM REPORT NO. 5" by Prof. William
Greene and Prof. Robert Smiley submitted on behalf of
the New York State Department of Law.

As of this date, we have not received a copy of
the ICF study for marginal cost based rate designs. We
hope that this study will be received soon enough to
allow us sufficient opportunity to comment.

Very truly yours,

A handwritten signature in dark ink, appearing to read "Neal Rauch".

NEAL RAUCH
Assistant Attorney General

NR:MS
Enc.

February 1, 1980

Mr. Neal Rauch
Assistant Attorney General
State of New York
Department of Law
Two World Trade Center
New York, New York 10047

Dear Neal:

Enclosed is our review and analysis of the I.C.F. Natural Gas Rate Design Study - January 10, 1980 - Interim Report (No. 5). The comments deal mostly with minor problems in the analysis, or questions of interpretation or exposition. This is because we are, in general, quite pleased with the analysis to date. We feel that I.C.F. has done a commendable job with its study of different average embedded cost rate designs, and we look forward to receiving, and commenting on, the marginal cost rate designs study.

Sincerely yours,

William Greene
Assistant Professor of Economics
Cornell University

Robert H. Smiley
Associate Professor of
Economics and Public Policy
Cornell University

/lft

Enclosure

1. The comments contained herein relate primarily to methodology. The comments do not go in detail into issues of appropriateness of the assumed parameters. We would suggest that the American Gas Association be asked to provide expertise on whether or not the assumed parameters and rate designs are realistic. With the exception of marginal cost pricing and lifeline rates, we feel that the study does analyze all reasonable rate designs. The descriptions of the distributors is fairly terse, so it is difficult to know whether or not they are reasonable or appropriate. With respect to DOE questions numbers 1, 2, and 4, (memo. from S. Skjei, 1/11/80, U.S.D.O.E.), as suggested above, we feel that the American Gas Association provides a more appropriate source for information. DOE question number 3 (Ibid.) is discussed to some extent below.

2. Page II-7, Item B

The description refers to "The natural growth of demand". This is rather imprecise term: the authors should specify what factors affect this "natural growth of demand". Presumably these factors include growth in population, growth in real income, and other items. What parameters were assumed for these growth rates? Were there sensitivity analyses on these rates? Do the parameters vary from company to company (A-B-C)?

3. The following comments relate to Appendix B - The Demand Model:

- A. In numerous places a "conservation effect", as distinct from a purely price induced elasticity effect, is discussed. Yet in the demand model this conservation effect is absent in formal terms. The authors of the study should reconcile this discrepancy.
- B. A number of significant demographic trends probably affect the forecast of the number of customers in the demand model. These effects are probably most important in the determination of the variable labelled TNU on page B-3. They may well be included in the DRI estimate of the growth parameter. If not, the authors should discuss how they (Demographic Trends) would affect this parameter (TNU) and perhaps consider them; if so the authors should discuss how these demographic trends are reflected in that growth parameter.
- C. There is no income effect in any of the demand equations which define use per customer. Note especially page B-5. There may be an important income effect in gas usage, for example, in the purchase of appliances, gas stoves, etc. The authors might address this question.

- D. The description of the residential demand model on page B-5 states that the long run effect would be due to the installation of heat pumps etc. However, the parameters of that model were estimated over a period during which the use of devices such as heat pumps was quite limited. Therefore, it is not unlikely that the long run elasticity in the demand model are underestimates of the true effect which we could expect to observe.
- E. The demand model is probably considerably more detailed than necessary. Throughout its construction it is assumed that various uses by customers occur in particular rate blocks, for example heating usage takes place in block one, non-heating usage, in block two given heating usage, and so on. However, the fact is that customers do not use gas in this fashion at all. The daily cycle of gas use includes all functions so that, for example, in the early part of the month, some gas in rate block one is used for heating and some is used for cooking. Given this, the model could be considerably simpler than the one the authors have used. It probably makes sense to have separate demand elasticity effects for heating customers and for non-heating customers. However, within these categories it

may not be necessary to have several elasticities within each rate block. A simpler model could probably be devised based upon the work of Lester Taylor in his Bell Journal survey in 1976 or 1977.

4. Table II.4, on Page II-9 describes growth in the number of interruptible customers. Prior to this point, the study has not described the terms under which these customers can be interrupted. What is being assumed about the terms of the contract for these interruptible customers? Under what conditions, and with what lead time can they be interrupted?
5. On Page II-8 it is noted that "growth and residential customers is affected slightly by differences among these rate forms, because of the small difference in average rate." This sentence seems to indicate that the authors have assumed that customers usage patterns are affected only by average rates and not by marginal rates. That is, customers are sensitive to their total bills and not to the marginal rate embodied in the total bill. Do the authors have empirical justification for this assumption? Much of economic theory would run contrary to the assumption that customers are sensitive to average prices and not to marginal prices.

6. The finding - on page II-14 - that "Industrial conservation shows little variation by size" is surprising. The authors should provide a discussion of the reasons why the amount of industrial conservation undertaken is not sensitive to price. Furthermore, the sentence in the middle of II-14 about the effect of declining block rates provides a unique opportunity for an observation about the perverse effects of declining block rates. The large customer obviously has more potential conservation opportunities, and since declining block rates reduce the number of those opportunities that the large industrial customer will invest in, declining block rates obviously have a perverse effect on conservation. This is an obvious point, and one that's been stated before, but the fact that the ICF model confirms the observation that a declining block structure is the worst of all worlds for efficiency purposes should be emphasized strongly.
7. The authors should discuss the reasons, in Table II-10, that the Northeast Utilities' residential customers bear a much higher proportion of the total distribution cost than do the residential customers of utilities B and C.

8. The first sentence in the section "Typical Residential Bill" on page II-20 is a peculiar one. The authors should be more specific: for example, "rising prices" of what? It is difficult to understand what they mean.
9. The discussion of volumetric rates on the first page of Chapter III is too brief. Although it is not clear, it appears that the authors have not allowed a customer charge (differing between classes) to be applied. This is an alternative form of volumetric rates - i.e. volumetric rates with a customer charge - which could have been used.
10. A more dramatic inverted block rate structure could have been used. In particular, the first block rate could have been structured similar to a lifeline rate. We are not advocating this alternative, but merely suggesting that the authors state clearly that their inverted block rate structure is not the oft-discussed lifeline rate.
11. The observation at the bottom of page III-9 is an interesting one. We had expected that inverted rates would lead to fuel switching that would dwarf any other effect they might have. But the model predicts that the fuel switching would be just about counteracted by the increased service to interruptible customers. How much confidence do the authors have in these results?

12. On the first page of Chapter IV, the authors should be clear about the use and implication of a "single cap" at the wholesale price of residual fuel oil. Exactly what does this mean? Are there alternative assumptions that are equally reasonable, and if so, why weren't they used? If the reader does not understand the use of this cap, the chapter itself is unintelligible. A discussion of the nature of "incremental" pricing would also be useful.
13. The major observation at the bottom of this first page of Chapter V is not clear. Perhaps it's because we did not understand the point in the body of the report, but this conclusion does not make sense.
14. The sentence on page V-2, that begins "by 1990, under..." may have a word missing. It is not clear which customers are referred to in the last four words.
15. We should also add, as a major observation, the fact that declining block rate structures lead to much less conservation by the customers who matter most (large volume users) than do any of the other rate structures.

16. The authors could discuss Table V-1 in more detail. In particular, except for the fact that the share of distribution born by residential and typical residential bills only score M, inverted rates seem to be preferred. Perhaps the authors could select two or three of the cases and compare them, i.e. flat rates with customer charge versus inverted rates.
17. On page V-4, the authors discuss price response changes to be made in the next phase. We would suggest varying the elasticity of demand as the price of gas approaches the BTU equivalent price of fuel oil. Actually, looking at Table I on page A-10, it appears that the fact that the elasticity varies by rate block may actually accomplish the variation we would like to see.
18. At the bottom of page A-11, the authors describe their "switchpoints". We would be interested to know just what the price premiums, above the price of the alternative fuels, were. Furthermore, what justification do the authors have for choosing these price premiums? In the description on page A-12 it appears that switching takes place immediately - that is, at the instant that the gas price passes the switchpoint. Is it possible to allow for gradual switching?

19. The cost allocation factors for plant and expenses are not clear. In Table IV, it is noted that three items - rate base, gross plant, and revenue are allocated "based on previous allocations". What are these allocations? Are the allocations in the table above these three items? It is not at all clear what is meant by "previous allocations". This is an important issue, and deserves more detailed treatment.

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State of Wisconsin \

PUBLIC SERVICE COMMISSION

February 15, 1980

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Mr. Stephen S. Skjei, Chief
 Regulatory Support and Analysis Branch
 Division of Regulatory Assistance
 Office of Utility Systems
 Economic Regulatory Administration
 Department of Energy
 2000 M Street NW
 Washington, DC 20461

File No.

Dear Stephen:

I would have replied to your 5th interim Report for the Gas Rate Design Study by January 30 as requested but was unable, because it was received here only on January 29.

As I read the report, I got the uneasy feeling that several of the alternatives to 3 tier "incremental pricing" have been structured in such a manner as to make "incremental pricing" come out as the preferred alternative.

Second, much of the results in terms of possible "switching out" from gas would depend heavily on the price of distillate oil and thus "switching in" points by distillate users. As the price of distillate climbs, relative to natural gas in your 1978 baseline year, the demand for gas will go up and the opportunity for new customers and reduction of high cost oil imports is enhanced. Several rate alternatives such as inverted rates, realistic volumetric rates, auction rates and benchmark rates may perform better than the system of exempt versus non-exempt incremental pricing.

In addition, it would be useful to select as a practical alternative, a mix of rate forms, not just say inverted rates for all customers. Wisconsin for example uses inverted rates only for small customers, i.e. residential and small industrial/commercial, preferring the use of benchmark rates for larger customers. Interruptible customers would ideally be on an auction rate which of course would not be workable with residential customers. Thus the real world would require a combination of rate forms to meet the needs and administrative cost constraints of each customer class.

Mr. Stephen S. Skjei, Chief
Washington, DC 20461

Page 2

Lifeline rates also need not be inverted block rates as suggested by ICF. Wisconsin is looking at the possibility of using a flat rate optional lifeline rate in Milwaukee with the standard rate being inverted.

Now to answer your questions.

1. Are the rate structures and levels for each rate form as simulated appropriate and reasonable?

In many cases no. Wisconsin for example uses volumetric rates quite extensively - we interpret that as having no demand charge. Yet the embedded class cost of service studies allocate capital costs to various classes. The ICF study assumes volumetric rates are the result of capital cost allocations on a volumetric basis. It then predicts that industrial customers would switch out of gas if volumetric rates were used! Even if the revenue requirement were apportioned by class on a volumetric basis as may be the case under some marginal cost of service studies, a distributor and his regulators should be expected to try to clear their market of natural gas (absent a white market) by setting appropriate price ceilings and promoting "switching in" of distillate oil and some electricity users.

Practical inverted rates receive a similar mechanistic treatment. Whether one set inverted rates on a marginal cost basis or not, we should expect that as long as out-of-pocket costs can be recovered gas prices will not be willingly set by distributors above the customer group's opportunity costs (unless sales lost can be replaced by additional sales to another group). Thus a realistic simulation of inverted rates would have to include a provision that the rate would gradually flatten as the customer's alternate energy cost were approached. In the meantime greater "conservation" effects would be expected.

Since industrial and commercial gas use is not as homogeneous as residential, (regarding a small set of appliances each with a typical use), inverted rates would be expected to impact heavily on very large use industrial customers and hence induce some unintended "switching out" (unless an unwieldy proliferation of rate classes were used based on size above). Hence the use of benchmark rates for such customers becomes important even under embedded costing unless the inverted rate is to be disposed of as a "straw man" alternative.

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Page 3

Since a historic benchmark is difficult to apply to interruptible customers owing to their curtailments and since these customers can move in and out of the gas market rapidly, - once the optimum allocation* of gas is made to the interruptible market an auction rate can be used to keep as many interruptible customers as possible on the gas system.

Finally, comparing a residential inverted rate with no customer charge to a flat rate with a customer charge (P.III-4) is appropriate. The lack of a customer charge for the inverted rate causes the model to induce some switching which results in remaining customers bearing an increased share of the revenue requirement.

This is not to say that the rate form with no customer charge is inappropriate. If a competitive market is to be the model for regulation, customer charges may be viewed as an avenue to extracting monopoly profits. In the northeast where customer charges are very high, even a partial elimination of the customer charge can be structured (relative to the status quo) as a more effective lifeline rate (to qualifying customers) than several inverted block designs.

2. Do the supply scenarios capture an appropriate range for future supply costs?

The assumption that all imported gas will prior to 1985 be at no higher than residual oil is optimistic. Canadian export prices are closer to distillate as of February of this year.

3. Are customer class price responses reasonable?

In general this does not appear to be the case since it looks like insufficient attention is paid to cross price electricity of demand with respect to oil.

It is difficult to accept the assumption (P. A-10) that "commercial elasticity is assumed to be the same for all consumption". It would seem reasonable as determined elsewhere that a commercial customer would have a significantly lower elasticity in the

*in terms of minimizing load balancing costs: i.e. the cheaper of a) carrying costs without debt service if storage is below capacity, b) annuallized costs of new storage where storage is used to capacity, c) cost of manufactured gas for peak use.
2) new load balancing customers.

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early part of his consumption. This unsubstantiated assumption favors declining block and flat rates over inverted and benchmark rates.

Residential demand (P. B-2) depends in part on $CRNGG_t$ = residential customers replacing non-gas furnaces with gas furnaces in year t , and on PEN = the percent market share of gas heating for new construction and furnace replacement. PEN in turn varies with average residential gas price and average oil and electricity prices. Penetration parameters are taken from the AGA TERA II Model, June 1, 1978. These parameters were developed during a time when oil heating was much more competitive with gas than at the present time. The parameters should be reexamined and results tested for parameter value sensitivity.

While prices of competing fuels enter explicitly in PEN it is not at all clear that $CRNGG_t$ captures the cross elasticity of demand since much depends on a probability estimate that a non-gas heated furnace will be replaced. If the estimate is subjective or based on past trends, it will not reflect the effect of changes in relative fuel prices.

In general it is inconsistent to use own price elasticities with great detail to indicate the price responsiveness by customers to increases in the price of gas without an econometric derivation in similar detail the coefficients for cross price elasticity when it is patently clear that the latter effects could swamp the former.

The commercial demand module relates gas demand growth only to "growth in real per capita income". The price of oil is completely ignored. This will understate commercial demand.

Industrial demand presently depends on (P. B-9)

"number of customers in each subclass

.price premiums that induce switching; and

.initial demands and elasticity (conservation) response"

and (P. I-8) "the rate of growth of the regional economy".

Thus "switching in" owing to a high price for oil does not appear to be considered. While it is stated (P. V-4) that an alternative industrial demand model using least cost engineering analysis is under development it is likely that it would be applied only to refine "switching out" so that some combustors could say switch to coal while others remain. I would be surprised if it were used to derive estimates of "switching in" since this would require combustor data of customers that at the present are not gas utility customers. This data may be very difficult and costly to obtain. Yet without "switching-in" estimates the demand

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module is hopelessly flawed. For example the rate of growth of the regional economy may turn out negative, but growth of gas use be high if the price of distillate oil is high relative to the price of natural gas.

On (P. II-8) para. 2 it is implied and (P. B-3) indicated that the average cost of gas prices determines the growth in residential customers. This would (excluding revenue requirement changes and the customer charge) negate differentials in "conservation" and "switching-in" among declining block, flat, and inverted rates. If a customer is deciding whether to install more efficient appliances or insulation, it is the price for marginal use that is relevant. The price for inframarginal use would not be relevant for these decisions. These marginal prices will be very different depending on whether we have inverted, flat or declining block rates.

Finally (P. II-14) the consultants conclude regarding flat rates, that "the greatest percent of gas savings are made by large residential customers who have the most weather sensitive demand". Considering the claims made that residential customers have lower price elasticities than industrial customers, it was argued that an improved price signal was necessary only to industrial customers. Given this conclusion, one wonders why incremental pricing is applied only to industrial customers?

4. Are the characteristics of the simulated distributors reasonable and appropriate?

Considering the additional work that will include a distributor in a producing state, the characteristics appear sound.

5. Which additional rate forms should be examined?

Benchmark rates and auction rates should be examined under both embedded cost pricing and marginal cost pricing. Most importantly a realistic combination of rate forms should be examined. Suggested is inverted rates that flatten out as alternate fuel prices are approached for small customers, benchmark rates for larger firm customers e.g. 75,000 therms a year or more, and auction rates for interruptible customers.

Sincerely,

Mo Reinbergs

Mo Reinbergs
Chief Economist

MR/dw

JOHN E. KEANE, JR.
DONALD F. ROGERS
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SANDRA MINCH HODES
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BALTIMORE, MARYLAND 21202
(301) 383-2375

January 28, 1980

Mr. Stephen S. Skjei
Chief, Regulatory Support and
Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

RE: Comments on Fifth Interim Report For
The Gas Utility Rate Design Study

Dear Mr. Skjei:

People's Counsel of Maryland is pleased to have the opportunity to comment upon the interim reports submitted thus far in the Gas Utility Rate Design Study. Our comments at this point of the study are an elaboration of the comments we made in the Public Hearings of January 16, 1980 on the Fifth Interim Report and specific technical comments on the construction and operation of the ICF model.

As John T. Schell, counsel for my office, noted at the hearing on January 16, People's Counsel is the statutory representative of utility consumers of the State of Maryland before the Maryland Public Service Commission and federal regulatory agencies. This role makes us particularly concerned with the implementation of any policies or evaluations flowing from this Study. As you know well, state regulation of retail utility rates operates in more than a theoretical vacuum and must reconcile competing equities in a highly visible

Mr. Stephen S. Skjei

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process. Our Maryland Commission, as well as most state commissions, will be concerned with the effects of changes in rate design upon consumers, as well as upon competing fuel sources.

We are favorably impressed with the general construction and use of the ICF model. We see it as a helpful tool to aid the Department of Energy and the Federal Energy Regulatory Commission in submitting its rate design proposals under Section 306, and not as an end result of this Study or as a technically precise evaluator of various gas rate designs. Taken in that context, we appreciate the need to construct a model based on various assumptions and approximations without having precise quantification of each variable. Nonetheless, we offer for your consideration the following comments and the attached comments of Dr. John A. Neri of H. Zinder and Associates, Washington, D. C.

Section 306 requires DOE to evaluate the effects of nine rate design "factors" or principles upon six items; (1) gas company load factors, (2) rates to each user class, (3) changes in total costs to consumers, (4) consumption of gas, (5) end-use gas company profiles, and (6) competition with alternative fuels. Five of these six items specifically involve "consumption" or "demand" for natural gas. Thus, it is apparent that Congress was, in Section 306, primarily concerned with natural gas conservation. Nonetheless, we submit that the other two general policies of PURPA, rate equity and operational efficiency, can also be considered in this Study.

Given that the main focus of the study is consumption effects of various gas rates and gas rate policies, the consumption calculations of the model become of critical importance. Herein lies the greatest weakness of the model. The elasticity equations contained in the

Mr. Stephen S. Skjei

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model are rudimentary and generally superficial, as is more fully described in Dr. Neri's comments.

We fully appreciate the extreme difficulty in being more specific on the demand side of the model, for most demand elasticities are simply not known. However, this routine, viewed in the light of Section 306, is the most critical operation of the model. Consumption and changes therein are the most important factors to be evaluated in this Study and the use of unspecific and average elasticities is inappropriate regardless of the level of detail for the rest of the model.

Examining the Fifth Interim Report, the various evaluations made of each rate design suffer due to this problem. For example, the tables showing quantity of gas consumed, changes in consumption levels, load factors and typical bills all predictably rise and fall based on the price, since the demand module establishes that relationship. Thus, the results are very much the product of the assumptions. We understand that ICF is working to provide more detail to the demand routines and we look forward to evaluating them.

In the Fifth Interim Report, incremental pricing was treated as a policy option. As you know, incremental pricing for industrial boiler facilities is now a fact as of November 1, 1979 and, in all probability, will spread throughout this year. We suggest that all of the rate analyses be run with incremental pricing of high cost sources of gas in accordance with Title II of the Natural Gas Policy Act of 1978 as a part of the supply prices.

Given the general policies of PURPA and those set out in Section 306 specifically, we believe that any full evaluation of the model must take into account an analysis the effect of marginal

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cost rates on the first six items. The Fifth Interim Report uses various rate designs, all of which are based on fully-embedded costs which, as would be expected, produces little real change in the various customer consumption levels based on the different rate designs. Accordingly, we await the next interim report which we understand will have an evaluation of various marginal cost rates on the six consumption factors.

Sincerely,

JOHN K. KEANE, JR.
People's Counsel

Enclosure

REVIEW OF ICF GAS UTILITY MODEL

I. Overview of ICF Gas Utility Model

ICF has developed a gas utility model which is used to conduct impact analysis in their natural gas rate design study for the Economic Regulatory Administration (ERA). This is a computer based simulation model of a hypothetical pipeline/distribution system.

The model solution begins with the transmission loop where gas demand is initialized. The hypothetical pipeline then secures supplies to meet this demand. The gas supply available to the pipeline is segregated into tiers where each tier represents a different gas vintage and price. Each tier has a unit price and a maximum available volume. Gas is purchased from the lowest cost tier first, then the next highest etc., until all of the transmission company demand is satisfied or supply is exhausted. (If supplies are exhausted, pro rata curtailment is imposed on the distribution company.)

Once the cost of gas is determined to the pipeline, pipeline rates are determined and the cost of gas to the distribution company is calculated. Distribution rates by revenue class are then determined in the distribution rate routine. The class rates are then fed into the demand model and a new set of demands are calculated. The new demands go back to the pipeline, new supplies are secured, the gas cost re-estimated, etc. This process continues until a convergence is achieved.

II. Deficiencies of the ICF Model

We have no problem with the conceptual framework of the overall model, but several of the sub-models are deficient.

A. Supply

- (1) The pipeline is assumed to secure supply discreetly each year. A static linear programming model is used to dispatch gas supply and optimized on a year-to-year basis. This approach does not allow for long term planning on the part of the pipeline where supplies are contracted for over time. The current ICF documentation implies that at the end of the simulation period (year) all contracts are off and totally new supplies are secured in each succeeding period. This is not realistic.
- (2) No discussion is given as to the determination of the gas vintages, the associated price and how they change over time.
- (3) Take-or-pay provisions are at the pipeline/distributor level, but do not seem to be at the producer/pipeline level. These provisions should be considered at the producer/pipeline level.

B. Demand

The key element of a gas rate design impact study is the transmission of a rate change into a change in demand.

This is done in the demand sub-model which unfortunately is the weakness component of the ICF gas utility model.

- (1) ICF claims to have a regional model which can simulate the regional impacts of gas rate design. This is not true. The demand model is based upon national level estimates which are imposed upon each of the three regional distributors. Recent studies have shown a wide variation in regional energy demand functions and elasticity estimates. ^{1/}
- (2) Residential non-heating customers (Appendix B) are estimated as a function of a simple time trend and lagged customers which shows the number of non-heating customers to decline over time. This equation should explicitly include the impact of relative energy prices, new construction activity, appliance saturation rates, income, and a linkage to tie non-heating customer conversion to the heating category.

^{1/} See for example, Hendrik S. Houthakker, "Residential Electricity Revisited," The Energy Journal (January 1980).

- (3) The number of heating customers equation is built up from a set of identities, the end product being simply a function of relative energy prices. Here again new construction, economic activity and appliance saturation rates should explicitly be considered.
- (4) Many of the parameters in the heating customer equation are based upon A. G. A. national data (e. g., the probability of not replacing a gas furnace $P(NR/ND)$). The model description indicates these parameters to remain constant over time. This assumption should be examined and if they do change, the causes should be identified.
- (5) The penetration variable (PEN) is a function of relative energy prices and is not constrained to be between zero and one.
- (6) The use per heating customer equation is based upon national data and estimated as a function of the average gas price, degree days and lagged use per customer. The lag formulation is used to obtain both short-run and long-run elasticities. As with all of the demand equations, supporting statistics are not presented such as R-square and t-statistics. These equations cannot be assessed without this information.

This equation is lacking in that it fails to consider income, number of people in the household and other measures of housing size which have been shown to be important determinants of residential gas demand. Exclusion of these variables will most likely overstate the price elasticity estimates.

- (7) Average price elasticity estimates are used to measure the impact of marginal price variations on gas demand. This is inconsistent and marginal price elasticities should be used in the matrices described on pages A-10 through A-12 and Tables B-1 through B-3.
- (8) Commercial customer count is projected as a function of national income per capita. Certainly, relative energy prices affect the decision to become a commercial gas customer.
- (9) Use per commercial customer is estimated as a function of the average commercial price of gas. The mix of commercial establishments is not considered as well as the impact of relative energy prices and the level of economic activity.

- (10) The use of constant price elasticity demand curves is probably unrealistic. Consumer response to price change is based on the level of gas price and the percent of total income spent on gas.
- (11) The industrial demand model is far from complete and this is noted in the ICF Report. With respect to fuel switching, no discussion is given as to how the "fuel switching point" is to be determined or what the response time will be. The ratchet effect of industrial load loss described on page A-11 is not seen by the model according to the discussion on page A-13. . . " The model applies a smoothing routine on each loop to assure a smooth convergence of supply and demand in the distribution model. " Industrial load loss, in fact, can be sudden and disruptive, therefor it may be unrealistic to smooth out this impact.

C. Transmission

- (1) Southern Louisiana companies have stable or declining rate bases while Rocky Mountain companies are generally growing rapidly. The model does not seem to account for these region differences in calculating the revenue requirements.
- (2) Not all pipelines have demand/commodity rates. For instance, only two lines flow into California and neither use this type of rate design. El Paso only has a commodity rate, making it highly sensitive to changes in volume. Pacific Gas Transmission, on the other hand, has a cost-of-service tariff which makes it relatively insensitive to changes in volume.

ADDRESS ALL COMMUNICATIONS
TO THE COMMISSION
CALIFORNIA STATE BUILDING
SAN FRANCISCO, CALIFORNIA 94102
TELEPHONE (415) 397-0507

Public Utilities Commission

STATE OF CALIFORNIA

February 11, 1980

792207 A

FILE NO

Steven Skjei
Economist
Economic Regulatory Administration
Department of Energy
2000 "M" Street, N.W.
Washington, D.C. 20461

Dear Steve:

RE: February 6 Meeting on Gas Rate Design Report
under Section 306 of PURPA

Thank you for arranging a meeting for us on such short notice. I believe the questionnaire to state regulatory authorities could make an important contribution to the report. I have given my suggestions to Chuck Gray of NARUC and recommended that he coordinate with your people in developing and collecting the questionnaire.

I hope that our meeting has provided input which will benefit the report. This will confirm my request for an opportunity for State Regulatory Authorities and NARUC to comment on your complete report draft prior to its submission to Congress.

Attached are my personal comments on the fifth interim draft. I regret that California has not provided more input at an earlier date but will urge that we do more subsequently.

Sincerely yours,

Walter Cavagnaro
Walter J. Cavagnaro
Energy Policy Consultant

Attachments

cc: State Participants in Meeting on February 6, 1980 (list attached)

List of Participants in February 6, 1980 Meeting in Washington, D.C.
on Gas Rate Design Report under Section 306 of PURPA:

Steven Skjei
Economist
Economic Regulatory Administration
Department of Energy
2000 "M" St., N.W.
Washington, D.C. 20461

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Iowa State Commerce Commission
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1102 Interstate Commerce Commission Building
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Public Utilities Commission

STATE OF CALIFORNIA

February 11, 1980

FILE NO

Steven Skjei
Economist
Economic Regulatory Administration
Department of Energy
2000 "M" Street, N.W.
Washington, D.C. 20461

Dear Steve:

RE: Fifth Interim Report for Gas Utility Rate Design Study

Comments to your questions for review are as follows:

1. Are the rate structures and levels for each rate form appropriate and reasonable?

I do not believe what the report identifies as traditional cost allocation methods have been used significantly at the retail level. Cost allocation for gas utilities has been significantly used at the federal level for jurisdictional allocation but the demand allocation methodologies differ from those utilized in these reports.

Appropriate and reasonable rate structures and levels are available from state regulatory authorities and retail gas utilities for 1979. These would provide a more reasonable starting point for your studies than the hypothetical numbers and relationships generated.

2. The supply scenarios may not capture an appropriate range for future supply costs. Canadian gas and other imported gas do not appear to be taken into account. The price assumptions for the base case seem optimistically low. Environmental requirements will probably place the price of gas above high sulfur fuel oil. It does not appear the most recent and anticipated oil price increases have been reflected. Compare the Table IV-8 cost of gas with the first quarter of 1980 approximate fuel costs in California (.55¢/therm for #2 fuel oil, .45¢/therm for #6 L.S. fuel oil).

3. We have not analyzed the report price responses but will try to send some data from CEC studies.

Steven Skjei
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4. The simulated distributors do not appear to capture all regional differences (supply scenarios, comparative class sales). I do not agree that Chapter IV should exam incremental pricing based on a single high sulfur oil cost.

Chapter V, Table V-1, may be very misleading in that the level of rates H-M-L is influenced by the allocation method more than the rate form. For example, inverted rates are not typically high for residential customers, but neither are they associated with peak responsibility allocation of embedded costs.

5. Alternate rate structures which should be considered are:

- (1) The seven rate forms indicated should be tested independent of embedded cost allocation principles.
- (2) Incremental Based Rates (alternative fuel oil pricing) should be examined for all interruptible customers, not exclusively for industrial customers, for at least three alternate fuels:
 - (a) #2 fuel oil
 - (b) #6 L.S. fuel oil
 - (c) #6 H.S. fuel oil
- (3) Residential Lifeline and inverted rates should be examined at various ratios of rate inversion.
- (4) The ERA solar guidelines should be included in the report with illustrative examples of their application.

Sincerely yours,

Walter J. Cavagnaro
Energy Policy Consultant

Consolidated Edison Company of New York, Inc.
4 Irving Place, New York, N.Y. 10003

February 7, 1980

Mr. Stephen S. Skjei
Chief, Regulatory Support
& Analysis Branch
Division of Regulatory Assistance -
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

Re: Natural Gas Rate Design Study
Interim Report on Simulation of
Seven Rate Forms - Submitted by
ICF Incorporated - January 10, 1980
(Fifth Interim Report)

Dear Mr. Skjei:

In your transmittal letter which accompanied the Fifth Interim Report you requested answers with respect to five specific questions. This letter is submitted in response to those questions.

Question I: Are the rate structures and levels for each rate form as simulated appropriate and reasonable?

Answer: The approach and methodology utilized in the Fifth Interim Report in developing the hypothetical rate structures studied appear to be reasonable. However, the levels for each rate form do not appear to be reasonable. For example, for New York State gas companies, utilizing the rates in effect at the end of 1979, the customer charges listed on Table II-2 for Distributor A (Northeast) are substantially overstated. Specifically, the Interim Report assumes for residential customers a monthly customer charge of \$7.11 under a flat rate and \$7.13 under a declining block rate (Table II-2). In fact, actual monthly minimum charges for this class of customers in New York State at the end of 1979 varied from a low of \$2.71 to a high of \$5.17 per month. Con Edison's current minimum charge for Service Classification

No. 1 - Residential and Religious is \$4.50 for the first 300 cubic feet (or less) of gas.

Since the rate per decatherm changes "by an amount that depends on the size of the customer charge and the average amount of gas consumed by each member of the class" (Interim Report p. II-5) some very unrealistic results occur when these rate forms are applied to Con Edison's Service Classification No. 1 customers. Specifically, due to the high number of minimum use customers on the Con Edison system, the rate per decatherm for Distributor A under a flat rate with a customer charge of \$7.11 would be 12 cents per decatherm rather than \$3.70 per decatherm. (On the Con Edison system 34 per cent of the gas bills are minimum use customers and approximately 89 per cent of the customers use less than 1.2 decatherm per month). Similarly, the flat rate without a customer charge of \$4.80 per decatherm for Distributor A would increase to approximately \$9.00 per decatherm given the quantity of gas sold to this class and the costs of serving these customers. In short, the price scenarios on Table II-2 are not realistic for Con Edison, and would probably not be valid for some other northeast gas utilities. Given these facts any conclusions which attempt to project the impact on usage of the hypothetical rate structures may have limited applicability.

Question II: Do the supply scenarios capture an appropriate range for future supply costs?

Answer: The supply cost picture as postulated by the base case for Distributor A is reasonable over the long run but the distribution companies may experience a different mix of supplemental supply in the intervening years.

Question III: Are customer class price responses reasonable?

Answer: We are unable to evaluate whether the customer class responses are reasonable.

Question IV: Are the characteristics of the simulated distributors reasonable and appropriate?

Answer: With respect to Distributor A, the overall characteristics are accurate and realistic with respect to northeast utilities in general. However, with respect to Con Edison in particular, our fixed costs (non-gas costs) are at a much higher level than the level reflected for northeast utilities in the base case.

Question V: Which additional rate forms should be examined?

Answer: At the present time we have no additional rate forms to recommend.

Very truly yours,

John Monsees
Assistant Vice President

JN/pm

COMMONWEALTH OF VIRGINIA

JAMES L. BRADSHAW
CHAIRMAN
PRESTON C. SHANNON
COMMISSIONER
THOMAS F. HARWOOD JR.
COMMISSIONER

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CLERK OF THE COMMISSION
BOX 1107
REHOBOTH VIRGINIA 22409

STATE CORPORATION COMMISSION

January 30, 1980

Mr. Stephen S. Skjei
Chief, Regulatory Support and
Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

Dear Mr. Skjei:

Your letter of January 18, 1980 submitting the fifth interim report for the gas utility rate design study was received on January 29, 1980. I regret that we are unable to submit comments by the January 30th (today) deadline. Also, due to the recent resignation of a key person in our organization we would not be able to devote the time necessary to study the report and make comments in the near future.

Thank you for the opportunity to participate in this exercise. I shall look forward with interest to receiving a copy of the final report.

Very truly yours,

Ryland Y. Bailey
Senior Engineer
Division of Energy Regulation

RYB:ln

LONG ISLAND LIGHTING COMPANY

EXECUTIVE OFFICES 250 OLD COUNTRY ROAD • MINEOLA, NEW YORK 11501

Direct Dial Number:

January 25, 1980

Mr. Stephen S. Skjei, Chief
Regulatory Support Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Skjei:

I have only, this moment, completed reading the "Fifth Interim Report for the Gas Utility Rate Design Study" which you released January 11, 1980. I have not had the opportunity to review the earlier reports. I would appreciate if, at the first opportunity, you could send me copies.

Obviously, it is very difficult to critique such a report in a matter of 45 minutes review, but it does appear that the report is well done and reads quite well. The thought occurs to me that although there are precise elasticities assumed regarding future increases as outlined in the scenario of replacing old gas with new gas, it would appear that there is no focus on cross elasticities of alternate fuels such as electric space heating and/or oil.

Unless the subject has been raised in the earlier reports, it would appear that some justification is required for developing a rate which reflects volumes only. In other words, if in fact the justification for rate design is one to follow some notion of costs, it would appear then that an arbitrary rate design, which only reflects assessment of costs on a volume basis, would require some scenario.

Thanking you in advance.

Sincerely,

Robert E. Ashburn, Manager
Economic Research Department

MITTELHAUSER
Corporation

5120 Belmont Road
Downers Grove, IL 60515
(312) 964-8164

February 18, 1980

Mr. Stephen S. Skjei
Chief, Regulatory Support & Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

Dear Mr. Skjei:

RE: Comments on Natural Gas Rate Design Study

I have recently concluded reviewing and analyzing the last two interim reports (interim reports four and five) which you forwarded to me. I appreciate the opportunity to expose myself to the development mechanics of the gas utility rate design study and furthermore, to comment on the methodology, analytical approach, scope and interim findings.

Initially, I want to apologize for not meeting your January 30 deadline for the reception of comments, but significant commitments on my available time prevented me from including it on my schedule before this past weekend. Moreover, I must admit that I did not assess or evaluate the numerous details, scenario effects on rate classification hierarchy or the sample model output from the oil price scenarios, incorporated in these two interim reports.

Overall, I found the reports very well structured both in terms of organization and in their coverage and attention to presenting the complexities of each integrated modular component. My constructive comments concentrate on three distinct factors within the model; elasticity, conservation and alternative supply sources. Upon reviewing both the output data, methodology, and flow diagrams, I concluded (and was later confirmed) that the elasticity of demand was assumed to be stationary. Although some price-induced effects are accounted for in the model's interactive stages, the final objective is determination of the number of households who 1) switch from the non-heating to the heating classification or 2) who obtained a natural gas connection for a new home. Furthermore, the initial elasticity was derived from a time series analysis which, although quite accurate in stable periods, may/does not take into account the post-OPEC shock to our economy and, more importantly, to the increased conservation of our non-renewable fuel sources.

LOS ANGELES

WASHINGTON, D.C.

Mr. Stephen S. Skjei
Department of Energy

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I believe that in the short-run the elasticity will not change significantly, but in relatively longer periods, I, as well as many other documented sources, feel that the elasticity of demand will move in magnitudes not forecasted in the past. Consequently, it might be advisable to generate demand elasticity on an annual basis and possibly include more variables than just a single time series. I would like to include the following caveat on this comment; the description of this particular point may appear in previous interim reports which I did not see or, if not included, may need further explanatory development in the final two interim reports to clarify my misinterpretation of its calculation.

My second area of comment evolves from the first and it pertains to conservation. Although the conservation issue and impact on natural gas demand/rates was factored into the model, its description was principally qualitative as opposed to quantitative. I was not able to understand how conservation was accounted for or implicitly/explicitly included in the econometrically derived demand equations. I believe that conservation is a very important national issue and, due to its documented cost-effectiveness, will be continually analyzed in future assessments. The ability of this utility model to accurately simulate the conservation factor with all the other economic and physical factors/parameters utilized in the model, will only enhance its acceptability, suitability and application in a broad spectrum of assessments.

Due to this potential, I strongly feel that conservation should be included as a separate component which affects demand, supply and most importantly the rate base. A study I performed for the State of Illinois and its primary gas utilities illustrated the effect of conservation measures on utility demand and determined the cost of the optimum measures if incorporated into the rate base (procedure commonly referred to as the Rosenberg Proposal). We found, as well as some of the Michigan utilities, that there is a tradeoff between conservation and new gas supplies. This comparison will become more prevalent as either supplies diminish and/or the economics of new sources preclude maintenance or expansion of the service area under the current rate schedule designs.

Finally, my last point -- alternative supply sources evolves from the previous paragraph. The President's current synthetic fuels initiative outlines the development of an industry to compliment and eventually supplement our current sources of gaseous and liquid fuels. If we contain this discussion to gaseous conversion facilities (i.e., gasification) then there are a number of projections which forecast the number of plants in operation by 1990. These estimates range from 6 - 44 depending on the source, the assumptions and, moreover, the economics and demand projections. I did not see anywhere, except in a series of

Mr. Stephen S. Skjel
Department of Energy

February 18, 1980
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tables located in interim report #5, the presentation or analysis of alternative fuel supplies. The data it presented and the corresponding analysis which preceded it did not discuss the inclusion of alternative supply sources (especially coal gasification) in the model. The data/analysis I allude to, was contextually only a sensitivity analysis of the model. If this option, of incorporating alternative supply sources and their economics into the model, is endogenous to the model, I do not think enough attention was addressed to its explanation and integrative mechanisms. If, alternatively, it is input exogenously as a sensitivity analysis, I think it should become a modular component since an economical and dependable (firm commitment) source of gas 1) to industrial customers is becoming low BTU gasification, and 2) for residential customers will eventually be originating from a high BTU gasification facility. The importance of this component is exemplified by the recent controversy about the North Dakota Coal Gasification plant and its distribution of costs over all customers served by the companies involved or only those who have access to the gas. In the future, justification for this type of facility could utilize this model as a source to indicate demand, rate base sensitivity and potential impact on the customers in each service class.

This concludes my comments and some substantiation of my basis for addressing them. I apologize if they were explained in more detail in the first three interim reports, but I temporarily misplaced them and therefore could not include in this critique. Thank you for sending the reports and giving me the opportunity to comment. Finally, I hope you can still include my comments where they are relevant and look forward to reception of the final report.

Sincerely,

David W. South
Economist

DWS:jwl

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 Daniel J. Demlow, Chairman
 Eric J. Schneidewind
 Willie Mae King

STATE OF MICHIGAN

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DEPARTMENT OF COMMERCE

WILLIAM F. McLAUGHLIN, Director

February 22, 1980

Stephen S. Skjei
 Chief, Regulatory Support
 and Analysis Branch
 Division of Regulatory Assistance
 Office of Utility Systems
 Economic Regulatory Administration
 2000 "M" Street, N.W.
 Washington, D.C. 20461

The Michigan Public Service Commission Staff (MPSC) wishes to take this opportunity to submit the following comments in regard to the Fifth Interim Report for the Gas Utility Rate Design Study and Draft Outline of Report to Congress.

The MPSC is concerned that the impact of the Utility Rate Design Study as set forth could have a devastating effect on all natural gas distributing utilities regardless of size. The regulatory jurisdiction of the MPSC covers eight natural gas distributing utilities. The size, customer mix, service area and supply sources are different for each of the eight utilities. The scenarios of the Natural Gas Rate Design Study do not realistically simulate any of these utilities.

A complete critique of the Natural Gas Rate Design Study would require extensive research, therefore our response will be confined to the five questions accompanying your memorandum.

1. Are the Rate structures and levels for each rate form as simulated appropriate and reasonable?

In the Rate Design Study the levels of the rates are based on full allocation of distributor cost using traditional cost allocation methods. The traditional rate allocation results in the residential customers paying the highest rate. In Michigan, residential rates are not the highest. The traditional cost allocation methods used in the Rate Design Study are not used in Michigan regulation. The determination of the cost to serve various classes of customers and to provide varying levels of service is without a doubt one of the most controversial rate design issues. The utility cost of service analysis is only used in roughly establishing rate levels. Value of service considerations, elasticity of demand, and conservation incentives also should enter the picture in the setting of rates.

In comparing Rate Design Scenario B number of customers to one of Michigan's larger utilities, the Michigan utility has three times more residential and commercial customers than Scenario B, one-seventh of Scenario B industrial-firm customers and about the same number of interruptible customers. All of Michigan's natural gas utilities have a higher ratio of residential and commercial customers than Scenario B simulates.

2. Do the supply scenarios capture an appropriate range of future supply costs?

The supply mix of each distributor utility is different and that utility's supply mix should be analyzed individually. A common scenario supply mix can not be developed to simulate all distributor utilities. The future supply cost for each distributor will be different dependent upon suppliers and suppliers' source mix. For example, the supply cost increases in 1979 for one Michigan gas utility increased 38.4% while another utility's costs increased 28.2%.

Other factors that are influencing supply costs include: (1) the Federal regulators oscilating between the United and Seaboard methods of allocation of pipeline rates, and (2) the escalation of Canadian natural gas prices together with Federal regulator's apparent intention to reject plans of U.S. companies for purchasing Canadian gas.

3. Are customer class price responses reasonable?

The customer class price responses seem to be reasonable within the limits of the scenarios. In reality, many factors influence price responses other than the price of natural gas. Some of these other factors are national and area economy and conservation program availability and implementation. Within the rate class factors to be considered are the mix of customers such as low and fixed income and elderly customers and housing stock. The incorporation of these types of factors into the Rate Design Model at the national level would be impossible, therefore this should be left to state regulatory agencies.

4. Are the characteristics of the simulated distributors reasonable and appropriate?

We do not believe the characteristics of the simulated distributors to be reasonable and appropriate. (See the above responses.)

5. Which additional rate forms should be examined?

We suggest that a scenario with a combination of rate forms be examined. For example, the scenario could include a residential inverted rates, commercial flat rates and firm industrial and interruptible incremental rates. Consideration should be given to various combinations of rate forms for one rate class such as residential rate class having both senior citizen and inverted rates.

Sincerely,

Wilbur F. McNinch
Supervisor, Rate and Tariff
Gas Division

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

Gas Utility)
Rate Design Study)

Docket No. ERA-R-79-22

FIRST SUPPLEMENTAL COMMENTS
OF
UNITED DISTRIBUTION COMPANIES

Pursuant to the request of Dr. Stephen S. Skjei at the public conference in Washington, D.C., on January 16 and 17, 1980, United Distribution Companies (herein called "UDC") submit these Supplemental written Comments relative to the Gas Utility Rate Design Study being conducted by the Economic Regulatory Administration (herein called "ERA") pursuant to Section 306 of the Public Utility Regulatory Policies Act of 1978 (herein called "PURPA").

UDC filed its initial comments herein on July 2, 1979, pursuant to ERA's Notice of May 3, 1979, and participated in the formal conferences held by ERA's Staff on August 9, 1979 and January 16, 1980. At the invitation of Dr. Skjei, these First Supplemental Comments address:

- (1) The draft outline of ERA's "Gas Rate Design Report" submitted by Dr. Skjei at the conference on January 16th, a copy of which draft is attached as Appendix A hereto;
- (2) The Fifth Interim Report of ICF and UDC's response to the five questions propounded by Dr. Skjei's letter of January 11th; and
- (3) The limited conclusions which may be drawn from this generic study of gas utility rate designs.

UDC apologizes for the delay in the submission of these comments. Because of the critical importance of ERA's report to Congress, however, and the consideration being given by ERA to "incremental pricing" as mandated by Title II of the Natural Gas Policy Act of 1978, it was deemed essential that these comments be postponed until completion of UDC's study of and comments on the Section 202 rule presently being considered by FERC at Docket No. RM 80-10.

Filed: February 25, 1980

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I
THE IMPORTANT AND VARYING
UTILITY SERVICES RENDERED BY
THE MEMBERS OF UDC

UDC is an ad hoc group of organizations engaged in the distribution of natural gas to the general public. The composition of the group, their areas of service and their critical interest in this Gas Utility Rate Design Study are set forth in UDC's written comments filed on July 2, 1979.

On July 25, 1979, several additional gas distribution organizations joined the UDC group; and UDC also employed Washington counsel. An up-to-date statement of the group's membership, areas of service, interest and representation is attached as Appendix B hereto.

Suffice it to say that UDC comprises 37 organizations rendering service to cities, towns and metropolitan areas located in the midwestern and eastern portions of the Nation ranging, from west to east, in the States of Arkansas, Missouri, Illinois, Wisconsin, Michigan, Indiana, Ohio, Pennsylvania, New York, Kentucky, West Virginia, Maryland and Virginia. The metropolitan areas served include those of Chicago, Peoria, Milwaukee, Detroit, Indianapolis, Toledo, Cleveland, Columbus, Pittsburgh, Buffalo, Albany, Rochester, Syracuse and Charleston. In the aggregate, these public services represent approximately 25% of the gas service throughout the Nation.

The individual members of UDC vary greatly in size, character of service area, character of service, consumer mix and weather patterns. Some serve rural areas; others are large utilities serving major metropolitan areas. Others serve both metropolitan and rural areas over major portions of particular states.

The sources of supply for the individual members of UDC vary greatly from one to another. Some are served by a single interstate pipeline; others by as many as five pipelines. Some have major local production; others do not. Self-help supplies, as storage, LNG and SNG, vary widely from company to company.

The rate structures and rate designs of UDC member companies vary significantly from one another; as do the unit costs of operations, the revenue responsibilities of particular service classes and other rate determining factors.

All members of UDC operate under the public service laws of the several states and are regulated by state commissions and/or municipalities. Each is obligated to render adequate service to the general public at rates which are designed to recover the overall cost-of-service. The rate designs incorporated in their several gas tariffs reflect a long history of development, as presented in the initial written comments filed on July 2, 1979.

II PROLOGUE

The Gas Utility Rate Design Study mandated by Section 306 of PURPA is of vital concern to every member of UDC; and before beginning its substantive comments on the matters at hand, UDC desires to express its appreciation for the manner in which the successive interim reports of ICF have been presented to the gas industry for analysis, and for the frank discussions of the study which have occurred at the public conferences on August 9, 1979 and January 16, 1980. It is believed that these exchanges have helped to demonstrate the essential nature of the rate design characteristics of the industry.

It is earnestly hoped and requested that this information and discussion process will continue as ERA prepares its final report and its recommendations to Congress. Both the report and recommendations must fully reflect the realities of gas distribution, the bounds and limitations which necessarily surround the design of rates for these essential public services and the absolute necessity for designing rates on an individual utility basis, according to the situation of the utility and the service which it renders.

It is believed that industry views and explanations will be conducive to this end; and UDC will be happy to submit draft explanations of distribution utility obligations, operations and rate design necessities for the consideration of ERA, if this is desired.

III SUMMARY STATEMENT

3.1 THE DRAFT OUTLINE OF ERA'S REPORT TO CONGRESS.

UDC's chief problem with the Outline of ERA's Report on Gas Utility Rate Design is that the essential function and nature of gas utility service and the bounds and limits of the design of rates therefore do not stand out as the centerpiece of the study, as they should. Indeed, the fundamental purpose of the study is almost lost in ERA's discussion of, and concern with, field price problems.

UDC, respectfully, submits that the report should commence with a detailed explanation of gas distribution, gas utility service to consumers and the function of rates and rate designs in the rendition of that service. In this regard the report must relate the ERA study to the two fundamental purposes of all utility rate designs, which purposes are: to provide revenues which will meet the overall costs incurred in the utility operation; and to distribute these revenue requirements fairly and equitably among several homogeneous classes of the users of utility service. And it must emphasize that in carrying out these purposes, rate designs utilize pricing mechanisms which reflect balanced and careful judgments based on the cost of serving the several classes, value of service, historical relationships and the necessity of coping with variations in weather and market demand. Since this is what Section 306 is all about, this explanation should be the centerpiece for all that follows in the report.

Only when these basic facts are understood and appreciated at the start can field prices, interstate pipeline operations and pipeline rates be viewed in their proper perspective. They should not, as in the Outline, lead off the discussion. Field prices and pipeline rates are of major concern to every gas distribution utility. Indeed, gas purchase payments made to a pipeline now represent as much as 80% of the total costs of a gas distribution utility. These facts play an important part in gas utility rate design; but one must first understand the nature of gas distribution before appraising what is to be done to improve gas utility rate design.

So too, the draft Outline fails to present the cardinal fact that rate designs must be viewed in their relation to total costs of operation and to the revenues and costs properly assignable to the several classes of service. One cannot appraise marginal or inverted rates for one class of service, for example, without appraising the effect which this will necessarily have on other classes of service and on necessary variations in service classifications to preserve homogeneity of service. Yet one gains the impression from the ICF study and from the Outline that rate designs are being viewed individually,--not as part and parcel of a seamless web and not in relation to changes in service classification which would be necessitated by new rate designs.

One always comes back to the fact that gas distribution rates are limited by overall cost-of-service and that changes in design for one class necessarily affect all others.

If, for example, one were to conclude that "incremental pricing" or marginal pricing should be used for one class of service in order to affect field prices, the rates to other classes would be decreased--discouraging efficiency and conservation by other users. This is the essential vice of the so-called "incremental pricing" mandated by Title II of the Natural Gas Policy Act of 1978 (herein called "NGPA"); it looks at only one aspect of the situation.

For these and other reasons, the following comments will suggest material additions to the text and analysis of ERA's report.

But, understandably, UDC is most concerned by the absence, from the Outline, of the conclusions which ERA will draw. For, in the consumer and public interest, these conclusions must be most cautious and limited and cannot suggest wide-ranging innovation and carte blanche change. They can, at most, recommend that certain designs be studied by individual companies and state utility commissions and that their affects be appraised in local rate proceedings.

UDC earnestly hopes, therefore, that the conclusions proposed to be drawn by ERA will be submitted to the industry for purposes of discussion. It is to the best interests of all concerned that these conclusions shall be realistic and properly limited.

3.2 THE ICF STUDY.

In essence, the ICF study is a computer model of the gas industry which utilizes three simulated gas utilities for purpose of analysis. One of these represents an "average" company in the Northeast. A second represents an "average" company in the Midwest. The third represents an "average" company in the Southwest. Each is provided with an assumed gas plant, an assumed set of utility services and an assumed supply mix. Rate design questions are then solved for future periods during which supplies, costs and customer responses to price follow assumed patterns.

The results of the operation of the model have been presented in the series of interim reports prepared by ICF and comparisons are made between the operations of different rate designs in these assumed circumstances.

Dr. Skjei's letter of January 11th has asked whether the several assumed rate structures, supply scenarios and customer price responses utilized in the study are "reasonable" and "appropriate". And the answer to this question necessarily depends on the conclusion which one wishes to draw from the results of the ICF study.

If one wished to conclude from such study that a given gas utility rate design should be used by any individual member of UDC, the answer is a resounding: "No!". For the factors utilized in the study do not fairly represent either the current or the future operation of any actual gas distribution company. And to utilize this study for the purpose of concluding or recommending that a given new rate design should or could be used by a real-life gas distribution utility could cause irreparable harm to the company, to the public whom it serves and to the National economy.

If, on the other hand, ERA carefully limits its conclusions to the rate design tendencies shown by this hypothetical study and makes no attempt to conclude that the studied rate designs will, in fact, work satisfactorily in the actual situations faced by individual gas distribution utilities, then the questions may all be answered with a qualified affirmative. The "future gas supply scenarios" could happen as assumed. UDC could suggest dozens of other supply scenarios, because each of the 37 UDC members will have a different future scenario; but those chosen by ICF are reasonable for a hypothetical study of rate design tendencies. So, likewise, as to the "rate structures" and "rate levels" for the three "average" companies. Each of the 37 members of UDC have different patterns of rate structure and rate level; but those chosen by ICF are reasonable for a hypothetical study of rate design tendencies.

Without being critical of ICF's hypothetical study as such-- (for it must be limited to a reasonable number of assumptions)-- these comments will show, in some detail, why the results of this study cannot be used to solve the rate design problems of individual gas utilities or to dictate that new and innovative rate designs should be used by individual gas utilities. These considerations conclusively show the narrow limits and qualifications which must be placed on the conclusions which ERA may properly draw from the study.

Rate design for real-life distribution utilities must be tailored to the necessities of the utility and the consumers whom it serves, as exemplified by the service area, the supply problems and all other factors developed in individual rate proceedings.

IV
COMMENTS ON THE
DRAFT OUTLINE OF ERA'S REPORT

4.1 INTRODUCTION.

ERA's report to Congress pursuant to Section 306 of PURPA will be of critical importance to all members of Congress, to the gas industry and to all consumers. It is imperative that the report present an appropriate analysis of the gas distribution industry and of its rate design characteristics; and that its conclusions be realistic and appropriate.

UDC is certain that ERA is approaching the problem in this fashion; and the following suggestions for the report are offered to this end.

Our comments will be keyed to the several headings of the draft Outline of the report attached as Appendix A hereto.

4.2 "I. INTRODUCTION"

Suggestion No. 1: Supplement the paragraph entitled "Principal Study Requirements" to incorporate the essential purposes of gas utility rate designs.

The draft Outline states, in paragraph B of section I, that

"the emphasis in the analysis will be on: economic efficiency, transfers of economic benefits among producers, pipelines, distributors and consumer classes; conservation; and competition with alternate fuels."

But this is far too limited an approach! The "emphasis" of the report should center on the nature and essence of the rates which are required for sound utility service in the consumer interest; and "economic efficiency" and other factors mentioned in this part of the Outline should be considered in the light of these fundamentals.

While Section 306 requires that the study "shall address the effect" of certain "factors" on several specified "items", this must necessarily be accomplished in the context of the Congressional mandate for a generic study of "gas utility rate design".

A gas distribution utility must provide adequate service to the public. This fundamental mandate stands first and foremost; and it is to be carried out at lowest reasonable overall cost. Rates for the service are designed in the light of this mandate, in order to provide the revenues which will cover these overall costs and to apportion the burden among users of the service in a just, reasonable and non-discriminatory fashion. ERA's study of "gas utility rate design" must be founded on an analysis of these fundamentals. "Economic efficiency", "transfers of economic benefits", "conservation" and "competition" must be considered in the light thereof.

4.3 "II. CURRENT STATUS OF THE GAS INDUSTRY"

Suggestion No. 2: Insert, immediately after the "Introduction", a new subsection providing a comprehensive description of gas distribution and the essentials of rate design.

Our chief problem with this section of the Outline is that gas distribution is presented as an "also-ran" rather than as the chief subject of the study. The proposed description of the industry places chief emphasis on field supply and pipeline operations, pricing of supply, and consumers.

This puts the cart before the horse. For the key element in the study is the nature and function of gas distribution; and this gets lost in the shuffle.

Gas distribution as a public service was here long before natural gas. It began with the distribution of gas made locally from coal and oil; and it will continue in being if all domestic field supplies and pipelines disappear.

The gas distributor is organized and in being to provide gas as a utility service to the whole general public in a given area; and under state law it is obligated to provide this service to the very best of its ability on a just, reasonable and non-discriminatory basis to all who wish the service.

It builds and operates a distribution plant. It secures supplies for this system from interstate pipelines, LNG, SNG, local production and any other sources. It renders service to various classes of customers. Its rates are fully regulated. Its overall rate level is designed to recover its total overall costs of operation, but only such amount. The rates for individual classes of service are designed to fairly and equitably apportion this overall revenue responsibility.

It is important that these obligations and these pricing concepts be included at the start of the study for they are fundamental to all that is to follow.

It is, therefore, suggested that there be inserted, immediately after the "Introduction" and before the discussion of "Sources of Supply", a new section which will describe gas distribution and the fundamentals of rate design in some detail. This should cover, in particular:

- (1) the general history of gas distribution, commencing in 1820;
- (2) the obligation to render service to the general public throughout an area of service;

- (3) the nature of the gas distribution plant;
- (4) the kinds of service which are rendered;
- (5) the requirement that rates and service be just, reasonable and non-discriminatory;
- (6) the regulation of rates by local authority;
- (7) the fixing of rates on an overall cost-of-service basis; and the absolute necessity to sound public service of having rates which will cover total costs;
- (8) the fundamental elements of rate design, which are:
 - (a) to provide revenues which will meet the overall costs of the distribution utility in rendering its services to the public;
 - (b) to distribute this revenue responsibility fairly and equitably among the several homogeneous classes of service adopted for the purposes of the particular rate design; and
- (9) the fact that well designed rates utilize pricing mechanisms which reflect balanced and careful judgments based on cost of serving the several classes, value of service, historical relationships among classes, the need for conservation, and the necessity of coping with variations in weather and market demand.

Suggestion No. 3: Insert, immediately following the foregoing subsection, another new subsection which presents the wide variations in distribution operations and services.

Any appraisal of gas utility rate design must recognize, at the very start, the manifold differences which exist between distribution utilities in size, service areas, consumer mix, utility plant, weather and other pertinent factors. Every one of these has a bearing on the rate designs which will work for this utility service.

Suggestion No. 4: Expand the discussion in section "B. Sources of Supply".

The section as drafted reads as though gas distribution began with the interstate pipeline and that this is the sole element in the picture.

Supply for distribution should be treated in historical perspective; and the place and probable future importance of local production, LNG, SNG, gas imports and other factors should be discussed.

The supply section should also emphasize the wide differences which exist between the supplies for various utilities, as exemplified by the above description of the UDC members.

Suggestion No. 5: Insert, in the "Current Status" section of the report, a new subsection discussing current, major problems of gas distribution.

When gas distribution was based on coal and oil gas, the gas utility, like many major electric utilities of today, was essentially an integrated independent entity. But from an institutional standpoint, gas distribution, at this point in time, is fundamentally based on supplies purchased from other corporate entities. Its costs of purchased supplies now represent up to 80% of total costs; and the costs of distributing these supplies are the minor element.

Both availability and cost of gas supply are so dominated, at the present time, by the operations of the interstate pipelines that the distribution utility has all too little flexibility of its own in operations and in rate design.

Furthermore, gas distributors have just survived a most difficult period occasioned by interstate pipeline curtailments during the 1970's. Service to the public was severely curtailed and hampered; and maintenance of industrial service (which is of great benefit to residential service) became extremely difficult. For the proper rendition of its whole service, gas distributors necessarily undertook expensive storage, supplemental supply and other self-help measures.

The absolute necessity of the gas distributor, now and in the future, is to maintain and gradually expand its overall public service in the face of rapidly escalating supply costs. The company must meet its tremendous supply and fixed costs, month by month, and its rates must be designed to achieve this purpose.

Assurance of revenues is critical to the public service. Maintenance of markets--particularly industrial sales--is important to the public service. All rate design must be subservient to these necessities.

Any study of rate design must be made in the light of these fundamental needs.

Suggestion No. 6: The statement of "Issues Raised" must be greatly modified.

(1) Efficiency/Conservation.

Efficiency and conservation is indeed a primary focus of public policy; and every gas distribution utility is striving to see that consumers do, in fact, conserve. Gas sales are highly price elastic; and as rates have increased during recent years, there has been a steady decline in unit consumption. Conservation will steadily increase among all classes of user as rates continue to increase under existing rate designs.

Based on the past and expected accomplishments of distribution utilities under existing rate designs, conservation is hardly an "issue". The ERA report should give full credit, for credit is due.

Furthermore, the report must recognize that gas rates are limited by overall costs. Gas rates are low, in relation to other fuels, but this is because overall costs of the gas industry are low. If one attempts to increase the prices to one class of service in order to force conservation by that class--(as is contemplated by so-called "incremental pricing" under Title II of NGPA)--one only ends up reducing rates to other classes of service and discouraging efficiency and conservation by them.

(2) Allocation of Economic Benefit.

The "economic benefit" of natural gas, as contemplated the Outline, is presumably the market value of this resource to the economy after taking into account the cost of production, transportation and distribution; and the person or persons who should receive the benefit is a most important question.

Congress can determine that the "economic benefit" of gas production shall be taken away from producers and passed-on through to consumers, as has been done in recent years under both the Natural Gas Act and NGPA. And the Outline of the report appears to contemplate that this process should somehow be continued through alterations in the design of gas utility rates.

But UDC, respectfully, submits that gas utility rates can play no significant part in this process; and that the whole concept should be laid to one side, for the purposes of this study and report.

Ostensibly the theory of the Outline is that, if industrial users are forced to conserve through increases in rates, this will bring down the demand for gas in the field and field prices will be reduced. Thereby, more of the economic benefit of natural gas will be flowed-through to residential users.

But this overlooks the fact that the rates of a gas distribution utility are determined by and limited to the overall costs-of-service which it incurs, including the costs of supply. Overall revenue responsibility cannot be increased above overall cost; nor can they be decreased below overall cost. A rate design,--such as marginal pricing--which increases the rates paid by industrial users necessarily works a concomitant reduction in the rates of residential and commercial users, lowering their incentive to be efficient and reducing the amount by which they conserve.

Overall, the demand for gas in the field may be as large or even larger than with existing rate designs.

Considering the overall cost limitation on utility rates, there is absolutely no way in which utility rates can effectively allocate the economic benefits of gas as between producer and consumer; and UDC, respectfully, submits that the whole subject--intriguing as it may be--should be dropped from this study of gas utility rate designs.

Furthermore, it should be noted that the transfer of "economic benefits" of natural gas does not appear to be a purpose within the contemplation of Section 306 of PURPA. That section states that ERA shall consider rate designs in the light of "wellhead natural gas pricing policies" established by Congress. But it does not contemplate that rate designs should be used to alter or affect those policies, as would be the case under the "transfer of economic benefit" theory suggested by the Outline.

4.4 "III. ANALYSIS OF TRADITIONAL RATE MAKING"

Suggestion No. 7: The "Introduction" to this part of the report should discuss the following additional considerations.

Nowhere in the analysis of traditional rate making is consideration given to the essential fact that gas rates are necessarily limited by the overall cost of operation and that rate design is the apportionment of the overall revenue responsibility among appropriate and homogeneous classes of users.

Residential gas rates are far below costs of oil and electricity for like services, but this is because overall costs of gas operation are low and because state commissions customarily apportion overall costs more heavily to industrial uses. So too, while industrial rates are customarily attuned more closely to value of service in terms of alternate fuel, they are low by reason of low overall costs of gas operation. Rate design must be kept within the bounds of overall cost and this places very definite limits on what is done.

Furthermore, since wellhead prices are discussed, this section should explain that pipeline rates stand between producer prices and consumer rates. The rates for distribution service are necessarily designed to meet pipeline, not producer, charges. The restriction or ordering of producer prices must come through alteration in pipeline rate structures. Altering the distribution rate alone is meaningless in this regard and can only weaken distribution service through making it more difficult for the distributor to meet the bills of the pipeline.

Suggestion No. 8: The "Benefit Allocation" section should be materially altered.

The "benefit allocation" section makes the statement that certain distribution "rate forms make the total system more sensitive to producer pricing and thus tends to capture more benefits for gas users".

UDC assumes that, in making this statement, ERA is referring to the "market ordering" concept claimed by some to be one of the purposes (though a far-from-certain purpose) of "incremental pricing" under Title II of NGPA, to wit: that raising industrial rates will cause industries to conserve, that demands for gas in the field will thereby be reduced, and that field prices will, therefore, be reduced. Ergo, more of the "economic benefit" of the resource will be captured for consumers.

The error lying at the base of this whole concept--(as UDC has pointed out to FERC in the comments filed on February 8, 1980)--is that raising industrial rates only reduces residential rates and the added conservation on the part of industry is offset by less conservation on the part of residential users. Indeed, existing utility rate structures are causing, and will cause, more overall conservation than will the injection of some innovative industrial rate form.

In this regard, it should be emphasized that residential and commercial uses are by far the largest portion of overall utility service and that the greatest potential for further conservation lies within these service classes. To reduce rates to these services strikes directly at the National policy in favor of conservation.

For the reasons set forth in Suggestion No. 6 above, it is, respectfully, suggested that the concept of "economic benefit" transfers between producer and consumer be dropped from the study of gas utility rate design.

Suggestion No. 9: The discussion of "Incremental Pricing" should be materially altered.

It is assumed that the section entitled "Incremental Pricing" proposes to discuss pricing under Title II of NGPA.

Since this is a rate design study, it is important that ERA show that "incremental pricing" under Title II is not incremental pricing in any rational or logical rate design sense.

True incremental pricing is pricing based on the assignment to a given service of the "marginal" or "incremental" or "out-of-pocket" costs incurred in rendering that service.

Title II, however, is a patent departure from this principle. It intentionally "loads" onto certain industrial users costs which are incurred in rendering service to residential users, the purpose being to "shield" residential users from their fair share of costs.

Congress was well aware of these facts, as is shown from the legislative history; but, when one is studying "rate design" as such, and trying to evaluate the practices of gas distribution utilities, one must recognize Title II pricing for what it is.

It is not sound "incremental pricing" as such. It has the effect of keeping residential rates below value of service, encouraging inefficiency and discouraging conservation. In an October 1979 study prepared by the Energy Information Administration and entitled "Pricing Provisions of the Natural Gas Policy Act of 1978," the Executive Summary contains the following statement, at page ii:

"While price protection of high priority users may be a desirable social objective, incremental pricing does induce some inefficiencies. Users receiving price protection are not provided with sufficient incentive to conserve, and users subject to incremental pricing surcharges may under-utilize natural gas. In addition, the desire to avoid, or mitigate, incremental pricing could lead to some inefficiencies in distribution and production."

UDC urges ERA to recognize the limitations and potential adverse consequences associated with Title II pricing.

4.5 "IV. ALTERNATIVE RATE FORMS"

Suggestion No. 10: The description of "Rate Methodologies" must be amplified.

- (1) The absolute limitation imposed by overall cost of service.

The description of rate methodologies must emphasize the fundamental principle that gas rates are limited by overall costs of service and a change in the design of the rate for one class of service in order to achieve some stated purpose will necessarily affect the rates of other classes, frequently with harmful results.

For example, Title II of NGPA was adopted by Congress in some part for the purpose of having a "market ordering" effect on field prices. The comments filed by UDC on February 8th emphasize that the Title II surcharges on industry can play only a very minor role in affecting field prices; but that they necessarily reduce residential rates with consequent impairment of overall efficiency and conservation.

Also, by way of example, if new residential users were priced marginally on a gas-cost basis and existing residential users were priced on the basis of low embedded costs, existing customers would be encouraged to increase their demands and to be inefficient. And if industrial users were priced marginally and residential users were not, the latter would be held below value of service and conservation by them would be discouraged.

So likewise, inverted rates, if not properly designed, could encourage inefficiency and discourage conservation among small users.

Every rate form must be carefully weighed in relation to this overall cost consideration and the affect on other services of the utility.

(2) The grave risk of revenue shortfall
inherent in innovative rate designs.

The discussion of rate methodologies must emphasize the absolute necessity of the gas distribution utility to meet its tremendous fixed costs and gas purchase costs, month by month, and the risks of shortfall which lie in any innovative rate.

For example, a switch from an existing flat rate to an inverted rate or marginal rate may occasion fuel switching or plant relocation by the affected users, thereby causing a shortfall in cost recovery. So too, pipeline curtailments which cause the reduction of deliveries to industrial users paying inverted or marginal rates would have a much more severe affect on distribution revenues than an existing flat rate and could lead to disastrous shortfall in meeting overall costs-of-operation.

These risks and burdens would tend to undermine the utility service to the detriment of all consumers; and any innovative rate must be carefully examined with this in mind.

The injection of a new rate into a rate structure can only be appraised and determined upon at the local level, in the light of all factors bearing on utility operation.

- (3) The necessity for reexamining and possibly regrouping customer classifications.

An essential ingredient of any sound utility rate design is that the many users of the service be grouped into classes which are rational and homogeneous; and the injection of a new design into a tariff may well necessitate a regrouping of consumers.

If this were not done upon the injection of inverted, marginal or other innovative rates, serious problems of equity and unfairness among users might arise. Moreover, too broad an application of these rate forms could render the utility unable to cope with changes in weather and economic conditions on a sound and satisfactory basis.

One shortcoming of the ICF study lies in the fact that new designs are injected and examined without recognition of the possible need for changes in class. The report of ERA must fully discuss these important rate design considerations.

- (4) Particular problems with marginal cost rates.

The Outline of the report indicates that ERA will place great emphasis on innovative marginal cost pricing as a means of controlling field prices; and it is important that,--over and above the foregoing general problems associated with any innovative rate--, the inherent weaknesses of marginal pricing as applied to gas distribution be fully explained and appraised.

As a matter of economic principle, marginal pricing only works properly when there is a direct connection between the consumer and the marginally priced cost--as is the case, for example, with a fully integrated electric utility having its own generating plants. Decisions by the consumer as a result of marginal pricing can directly affect the use by the utility of a given generating plant.

In the case of gas distribution, however, there is a most tenuous connection between consumer use and producer prices; and a decision by an industrial user not to take gas may have no affect whatsoever on producer prices. The fact that marginally priced industrial rates may lead to offsetting residential use has already been mentioned. But beyond this is the fact that the interstate pipeline lies between the producer and consumer and the fact that the distributor's take from the pipeline is determined by its overall operating situation--taking into account local production, LNG, SNG, weather conditions and storage--and not by industrial use alone.

Even if the volume of take by a distribution utility is reduced by the application of a marginal rate to industrial use, this fact has no direct bearing on the prices paid by an interstate pipeline in the field. The long term reserve situation of the pipeline, the flowing gas situation, the take-or-pay provisions of its contracts and numerous other factors--all beyond the control of the gas distributor--dictate the purchasing policies of the pipeline and the prices which it is willing to pay.

Suggestion No. 11: The "Impact Analysis" of
"Efficiency and Conservation" must be
amplified.

Efficiency and conservation are steadily increasing among all classes of user, as rates increase under existing rate designs and utilities and state commissions assiduously work toward these ends. This is clearly shown by operating results during recent years; and the report should recognize these accomplishments. It is very doubtful that innovative pricing will improve these overall results, primarily because an innovative design for one class would reduce the rates to other classes and probably discourage overall efficiency and conservation.

V

QUESTIONS RELATIVE TO THE ICF STUDY5.1 INTRODUCTION.

In essence, ICF has constructed three "average" gas utilities,--simulating a company in the Northeast, one in the Midwest and one in the Southwest, each of which is provided with an assumed market, supply situation and operating plant. Then the operations of various rate structures are tested over periods of time during which market, supply and operations follow assumed future courses.

As pointed out in the SUMMARY STATEMENT above, the validity of the assumptions and data which lie at the base of this hypothetical model of the industry is wholly determined by the conclusions which one wishes to draw. Correspondingly, the conclusions which may be drawn are determined by the nature of the model and the assumptions and data which are utilized therein.

That the ICF study does not and cannot demonstrate the proper gas utility rate designs for individual gas distribution utilities is conclusively shown by several examples. These are presented to demonstrate the limitations of the model and not criticize the use of hypothetical companies to evaluate various rate tendencies. It cannot be emphasized too strongly that no hypothetical model can be the basis for designing rates for a gas utility since each distribution company has its own special operating characteristics.

5.2 COST ASSIGNMENT PROBLEMS.

The model assumes that utility rates are designed through the exact apportionment of fixed costs among the several classes of service; and the operations of various rate designs are tested and compared from this starting point.

But, in point of fact, residential rates, and particularly small volume residential rates, absorb much less than their proper share of fixed costs and large volume sales absorb more than their fair share of these basic costs of distribution.

Loss of large volume sales through some innovative rate design could have catastrophic effects on the financial well being of the distribution operation and hence on the service of all consumers, particularly small residential users.

These effects can only be appreciated when rate designs are tested in the operations of individual real-life utilities. The results in one case could be materially different from another, and both would undoubtedly differ from the model.

5.3 PRICE RESPONSE PROBLEMS.

The model assumes a given pattern of future response to changes in rate level, for residential, commercial and industrial consumers; and the operations of various rate designs are tested and compared on this basis.

But conservation varies widely according to the extent of conservation which has already taken place, the character of the loads served by a given utility, and other factors; and the action of various rate designs will vary accordingly.

For example, some types of industrial load can greatly increase their efficiency of use; while others cannot, as was demonstrated by evidence introduced by the DuPont Corporation in the proceedings before FERC involving the rule under Section 202 of NGPA. The usefulness of a particular rate design intended for conservation would vary between distribution utilities depending on the mix of industrial loads.

So too, with residential and commercial loads. The usefulness of an inverted rate for conservation will differ markedly depending on the size and character of the heating loads in the community, as well as weather patterns. A metropolitan area dominated by apartments and older homes could provide far different results from suburban areas dominated by large single family residences.

In short, overreliance on the hypothetical model to predict conservation is dubious. It is clear, however, that conservation is occurring under existing rate designs tailored to the operating characteristics of the distributor.

5.4 LOSS OF LOAD PROBLEMS.

The model assumes a very rosy approach toward fuel switching and toward the attachment of new industrial loads when existing loads are lost for any reason; and the efficacy of studied rate designs are viewed in this light.

The fact may be far different from these assumptions, however. One need only read the newspapers to appreciate the disastrous consequences visited on communities by the loss of industrial plants; and the difficulties standing in the face of replacement are manifold.

The loss of large industrial load for any reason--fuel switching, plant closings, plant movings--is a very serious problem to any distribution utility and to all of the residential, commercial and other users whom it serves. The benefits conferred on residential users by industrial sales are very large. So too, are the benefits conferred on the National economy and on the energy situation.

That the rate design for any given utility must be most carefully evaluated in the light of its own potential load loss problems goes without saying. This goes to the heart of gas utility service. And it cannot be said in advance that any given rate design, however meritorious it might otherwise be, will satisfactorily cope with the problem.

5.5 OVERALL REVENUE PROBLEMS.

The model in all cases assumes that the rate designs will carefully provide revenues required to meet all of the costs of operation.

But UDC cannot overemphasize the potential shortfall in revenues--and the consequent harm to the consumer and public interests--which can be occasioned by innovative rate designs applied under improper circumstances. This has been pointed out above, in our discussion of innovative rate forms.

A gas distribution utility is faced, month after month, with gas purchase costs which represent the bulk of the overall costs of the public service which it renders, as well as fixed costs for labor, capital and other necessities. Things are very tight and the utility has little room in which to move.

This is not the day for cavalier experiment with distribution rates for the purpose of achieving National purposes which are not within the control of the utility itself--for a rate not fitted to the specific operation can affect the financial viability of the utility.

A utility can design rates to achieve efficiency and conservation by its own users; and this is being effectively done. But to experiment with utility rates with the view that this will affect field prices in a given manner is another matter. This is the vice of so-called "incremental pricing" embodied in Title II of NGPA. It can, if not properly applied, disrupt the utility market and impair the ability of the distribution utility to function.

In real life it cannot be assumed, as does the ICF model, that necessary revenues will be provided by innovative rate designs. The matter must be studied, on a company-by-company basis, in the light of each utility's operations, with cardinal emphasis being on what will keep the service going on a sound basis and not on social or economic purposes outside the scope of utility operation.

5.6 PROBLEMS OF EQUITY AMONG CONSUMERS.

The ICF analysis of various rate designs, such as inverted rates and marginal rates, assumes as a base that the selected rate forms--designed for the achievement of assumed National purposes--will be just and reasonable as among all of the consumers served by a utility.

But this may not be true. In real life, other rate designs may well achieve the same overall National purposes while representing a more reasonable balance among customers in a given area.

In a given area of service, for example, just as much conservation may be achieved by flat rates as by inverted rates and flat rates may more equitably spread costs of service among users. A poorly designed inverted rate can thrust more than their fair share of costs onto heating customers and unduly subsidize the small residential users, thereby discouraging conservation on their parts.

5.7 PROBLEMS OF GROUPING AND CLASSIFICATION.

In its examination of innovative rates, the ICF study assumes that new rates may be injected into utility rate design without any change in existing customer classifications.

This is quite all right, and probably necessary, for a hypothetical study of rate tendencies. But, in real life, the study of possible new rate designs is always accompanied by a review of consumer classifications; and when new rate forms are adopted, this may well be accompanied by a reclassification. This step may be essential to the maintenance of revenue stability and to coping with weather fluctuations, pipeline curtailments and shifting demands.

VI
THE VERY LIMITED CONCLUSIONS
WHICH ERA CAN INCORPORATE
IN ITS REPORT

The draft Outline does not suggest the nature of the conclusions which will form a part of ERA's report; but it is obvious that the nature and purport of these conclusions are of critical import.

The foregoing comments demonstrate, we submit, that this broad Federal study of gas utility rate designs, as mandated by Congress, necessarily inquires into and indicates no more than the general tendency of various rates to carry out perceived purposes and policies. It cannot, by any stretch of the imagination, demonstrate how any given rate will perform when implemented by an individual gas distribution company,--whether it will accomplish the desired purposes and policies--, and, most importantly, whether it will impair this important public service and the interests of consumers and the National economy.

Indeed, the injection of an ill-designed or ill-advised, innovative rate--particularly marginal rates and inverted rates--into the rate structure of a given utility can cause irreparable harm to consumers, the National economy and the public service.

The conclusions to be drawn by ERA must be most cautious and limited for they touch upon the very life-blood of an important public service.

It is submitted that ERA may and should conclude from this hypothetical and necessarily limited study:

- (1) that the rates for gas utility service are necessarily designed for and limited to the recovery of the overall cost of service of the distributor;
- (2) that a change in the design of the rate for any class of user necessarily affects the rates for all other classes, with the result that increasing one rate to accomplish any Federal economic purpose necessarily decreases other rates with adverse affect upon such purpose;
- (3) that the injection of any innovative new rate into the rate structure of a gas utility may impair its ability to recover its cost of service, lead to unfairness and inequity among consumers and undermine the public service in the area; and

- (4) that, in consequence, innovative rates can be utilized in the service of a distribution utility only after full study of all of the consequences of such use by the distribution utility, the local state commission and the consumers served by the utility.

IN CONCLUSION, UDC can only emphasize over again the gravity of this mandated study, for, as has been said above, rate design goes to the very heart of sound public service in the consumer and public interest. It is earnestly hoped that the report will be modified and amplified in accordance with the foregoing suggestions and that the conclusions will be extremely cautious and limited in the manner which has been set forth.

UDC will gladly assist to these ends in any manner which ERA may desire. It is sincerely urged that drafts of the report and its conclusions will be submitted for industry consideration and comment and that several conferences between ERA's Staff and representatives of industry, consumers and state commissions will occur as the matter moves forward.

Respectfully submitted,
UNITED DISTRIBUTION COMPANIES

C. William Cooper
159 Town Hall Square
Falmouth, MA 02540

J. Richard Tiano, Esquire
Reid & Priest
1111 19th Street, NW
Washington, DC 20036

AFFIDAVIT

Commonwealth of Massachusetts)
County of Barnstable) ss.

C. William Cooper being first duly sworn deposes and says that he is the Vice Chairman and General Counsel of United Distribution Companies, that he has had over thirty years of experience in distribution, pipeline and producer rate and operating matters,

both as an official of and attorney for gas distribution companies, that he has prepared the foregoing comments in consultation with members of UDC, that the statements therein set forth are true and correct to his best information, knowledge and belief and that he is duly authorized to execute and file the same with the Economic Regulatory Administration on behalf of UDC.

C. William Cooper
C. William Cooper

Subscribed and sworn to before me this 22nd day of

February, 1980.

Luca E. DeGidio
Notary Public

LUCA E. DEIDIO
Notary Public

Commission Expires June 8, 1984

DRAFT

Appendix A

GAS RATE DESIGN REPORT OUTLINE

I. Introduction

A. Legislative Background

Describes the objectives of PURPA and NGPA. It will also outline the specific requirements of Section 306 of PURPA.

B. Principal Study Requirements

Shows how the objectives of the act interrelate and will outline the issues to be covered in this report: effects of traditional rate forms, effects of marginal rate forms, and role of wellhead pricing, pipeline pricing and contract terms. It will also stress that the emphasis in the analysis will be on: economic efficiency, transfers of economic benefits among producers, pipelines, distributors and consumer classes; conservation; and competition with alternate fuels.

C. Organization and Approach

Describes how the study was done and how the remainder of the report will be organized.

II. Current Status of the Gas Industry

A. Introduction

Chapter provides a brief overview of the gas distribution system (including distributors, pipelines and producers). The overview will highlight the relevant structural (including regulatory) elements which impinge on rate making, and the changes that have recently taken place.

B. Sources of Supply

Shows how the natural gas industry grew up to distribute gas that was abundant and cheap relative to distribution costs. In the early 1970's the supply failed to keep up with demand and there was substantial curtailment. Wellhead prices have risen more than tenfold at the margin. In the face of uncertain supply both pipelines and distributors are investigating supplemental sources of gas, which are expected to cost even more than the marginal wellhead price. There is also uncertainty concerning the behavior of the wellhead price of gas after 1984.

C. Institutional Factors**1. Wellhead Pricing**

Description of FPC/FERC price controls under the Natural Gas Act and NGPA through 1990. Includes the significance of the intrastate market before NGPA and after. Points out some possible lines of behavior in 1985 and after as NGPA controls phase out. Describes how pricing may continue to differ between the inter and intrastate markets.

2. Pipeline pricing and costs

Discusses pipeline costs at various stages of delivery: wellhead costs (and contract restrictions), storage, transmission. Covers nature of pipeline costs, including changing perspective of gas costs versus operating and capital costs, including the significance of the United and Seaboard pricing formulas. Will discuss the past controversies concerning average pricing vs. marginal pricing, and will briefly describe incremental pricing as defined in NGPA. Will also describe expected impact of phased decontrol on the aggregate inter and intra state systems.

3. Distribution company pricing and costs

Discusses distributor costs, including: gas costs, distribution operating costs and investment costs. Will trace recent history of changes in these costs. Will discuss other factors such as curtailment and hookup moratoria. Will outline current typical rate patterns (declining block rates and flat rates with and without customer charges) and traditional rate making procedures. Also will describe some currently applied innovative rate forms or methodologies, including those developed in California and Wisconsin as well as incremental pricing (NGPA) and marginal rates.

D. Gas Consumers

Describes the nature of gas consumers; residential, commercial and industrial. Shows how the pattern varies by region, by inter vs intrastate, etc. Discusses the uses made of gas, and the options open to each group in terms of conservation, both direct (resetting thermostats, etc.) and delayed (involving capital investment in insulation or equipment). Discusses potential for fuel switching and conservation for each group.

DRAFT**E. Issues Raised**

This background raises several issues that fall into two groups: one concerning efficiency and conservation, and the other concerning the allocation of economic benefits. Efficiency/conservation issues highlighted are: under-pricing/overconsumption/inadequate conservation, non-uniformity of pricing (with its corollary of "area rents"), intra vs. interstate differences even under NGPA, choice of increasing supplemental supplies vs more emphasis on gas well development, and continued service of lower value customers when higher valued ones are curtailed. Benefit allocation issues will include: tradeoffs between producers and consumers, benefit allocation among classes, among distributors and among pipelines.

III. Analysis of Traditional Rate Making**A. Introduction**

Purpose is to illustrate current rate making, to show how the effects of typical rate forms vary under four different distributor conditions and different supply conditions.

Discussion will cover a period through 1990 to show effects of decontrol of wellhead prices. Where 1990 results are similar, but different paths of adaptation are used, present value of benefits will be compared.

B. Description of Rate Allocation and Rate Forms

Describes rate forms and methodology to be covered: embedded cost rates using flat rates with and without customer charge and declining block with conventional pipeline pricing and current implementation of NGPA wellhead pricing.

C. Impact Analysis***1. Efficiency and conservation**

Shows how rate forms change the overall consumption level for gas, and what changes take place within class. Discusses effects of rate forms on conservation and risk (company revenue stability and operating costs). Describes amount of load shifted to or from other fuels. Shows how varied response can be for different distributors and/or external conditions. Will discuss potential losses from curtailment.

* Based on Study-supplied as Appendix.

DRAFT**2. Benefit allocation**

Shows how different rate forms transfer costs among classes and subclasses of gas customers. Also shows how some forms make total system more sensitive to producer pricing and thus tend to capture more benefits for gas users. Shows how different regions or types of utilities show some responses sooner than others. Discusses possible effects on pipeline pricing and gas purchase decisions.

3. Incremental Pricing

Special discussion of role of incremental pricing in terms of ways in which it cuts across results of above analysis. Discussion of what aspects of incremental pricing regulations and of distributor characteristics amplify the effects. Shows how results are affected by different supply assumptions.

D. Issues Raised

Discusses issues raised by current system and potential role of rate reform. Will include system tendency to underprice and create more demand than there is gas available; problems of distribution of economic benefits; role of gas with respect to imported oil. Shows how differences in company characteristics change the effects of different rate forms.

IV. Alternative Rate Forms**A. Introduction**

Purpose is to discuss impacts of innovative rate methodologies and pipeline/wellhead issues. Will cover marginal rate making, pipeline pricing, gas cushions, etc.

B. Description of Rate methodologies

Discusses marginal pricing issues, gas cushion and post 1984 wellhead pricing issues. Describes rate methodologies and rate forms to be reviewed; seasonal rates, inverted rates and alternative pipeline pricing options.

C. Impact Analysis**1. Efficiency and Conservation**

Shows how different approaches affect end use consumption patterns. Discusses potential interactions with oil consumption. Shows how pricing decisions at wellhead, pipeline

and distributors affect choice of gas source and discusses appropriateness of resulting signals for effective planning by pipelines and distributors. Also addresses impacts on conservation and relation between customer classes.

2. Benefit Allocation

Describes problems raised by location differences, regional cost and consumption pattern differences, and shows how rate methodologies affect these problems. Discusses the forces that transfer benefits between producers and consumers among different distributors. Shows how rate decisions and other contract terms by pipelines may change the way the overall system adapts to changes.

3. Other

Reviews marginal pricing at distributor, based on prices to distributor from its supply sources. Discussion of roles of incremental pricing, curtailment and supplemental gas sources. Discuss volumetric rates.

V. Conclusions

A. Introduction

Purpose is to summarize and highlight how significant changes in conditions surrounding the gas transmission and distribution industries may require some adaptation of pricing behavior.

I
IDENTIFICATION AND INTEREST
OF UNITED DISTRIBUTION COMPANIES

United Distribution Companies (herein called "UDC" or "UDC Group") is an ad hoc group of 37 organizations engaged in the local distribution of gas to the general public. The names of the Members of UDC are listed on the next page.

In the aggregate, UDC Members provide approximately 25% of the local gas distribution service rendered throughout the entire United States. Their areas of service comprise cities, towns and metropolitan areas located in the northern and eastern portions of the Nation ranging, from west to east, in the States of Arkansas, Missouri, Illinois, Wisconsin, Michigan, Indiana, Ohio, Pennsylvania, New York, Kentucky, West Virginia, Maryland and Virginia. The metropolitan areas served include those of Chicago, Peoria, Milwaukee, Detroit, Indianapolis, Toledo, Cleveland, Columbus, Pittsburgh, Buffalo, Albany, Rochester, Syracuse and Charleston.

Formed in 1969 as a result of the National shortage of supplies available to their interstate pipeline suppliers, and the consequent depreciation of their own important services to the consuming public, UDC's efforts have been devoted to the task of increasing supplies. To this end, UDC regularly intervened and actively participated in all area and National rate proceedings before the Federal Power Commission and Federal Energy Regulatory Commission.

As distribution utilities, the Members of UDC are vitally interested in the study of gas utility rate design mandated by Section 306 of the Public Utility Regulatory Policy Act of 1978.

The names, addresses and telephone numbers of the persons to whom communications concerning this proceeding are to be addressed are:

C. William Cooper
159 Town Hall Square
Falmouth, MA 02540
617-540-0330

J. Richard Tiano, Esquire
Reid & Priest
1111 19th Street, NW
Washington, DC 20036
202-828-0100

UDC MEMBERS

ASSOCIATED NATURAL GAS COMPANY
BATTLE CREEK GAS COMPANY
CENTRAL ILLINOIS LIGHT COMPANY
CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
CITIZENS GAS & COKE UTILITY
CITIZENS GAS FUEL COMPANY
COLUMBIA GAS OF KENTUCKY, INC.
COLUMBIA GAS OF MARYLAND, INC.
COLUMBIA GAS OF NEW YORK, INC.
COLUMBIA GAS OF OHIO, INC.
COLUMBIA GAS OF PENNSYLVANIA, INC.
COLUMBIA GAS OF VIRGINIA, INC.
COLUMBIA GAS OF WEST VIRGINIA, INC.
CONSOLIDATED GAS SUPPLY CORPORATION
CONSUMERS POWER COMPANY
THE DAYTON POWER AND LIGHT COMPANY
EAST OHIO GAS COMPANY
EQUITABLE GAS COMPANY
ILLINOIS POWER COMPANY
INDIANA GAS COMPANY
KOKOMO GAS AND FUEL COMPANY
MICHIGAN CONSOLIDATED GAS COMPANY
MICHIGAN GAS UTILITIES COMPANY
MISSOURI UTILITIES COMPANY
NATIONAL FUEL DISTRIBUTION CORPORATION
NIAGARA MOHAWK POWER CORPORATION
NORTH SHORE GAS COMPANY
OHIO GAS COMPANY
ORANGE & ROCKLAND UTILITIES, INC.
THE PEOPLES GAS LIGHT AND COKE COMPANY
PEOPLES NATURAL GAS COMPANY
RICHMOND GAS CORPORATION
RIVER GAS COMPANY
ROCHESTER GAS & ELECTRIC CORPORATION
THE TOLEDO EDISON COMPANY
WEST OHIO GAS COMPANY
WISCONSIN GAS COMPANY

STATE OF CONNECTICUT
DEPARTMENT OF BUSINESS REGULATION
DIV. OF PUBLIC UTILITY CONTROL

February 21, 1980

Stephen S. Skjei
Chief, Regulatory Support & Analysis
Division of Regulatory Assistance
Office of Utility Systems
ERA
Washington, D.C. 20461

Dear Steve:

The enclosed is for your information.

Sincerely,

A handwritten signature in cursive script, reading "Charles T. Caprino".

Charles T. Caprino
Director, Rate Analysis & Research

Enclosure: Rate Design Comments to NARUC

345
STATE OF CONNECTICUT
DEPARTMENT OF BUSINESS REGULATION
DIV. OF PUBLIC UTILITY CONTROL

February 20, 1980

Charles D. Gray
Assistant General Counsel
National Association of Regulatory
Utility Commissioners
1102 Interstate Commerce Commission Building
Constitution Avenue & Twelfth St., N.W.
Post Office Box 684
Washington, D.C. 20044

Re: Department of Energy - Gas Utility Rate Design Study Required Under
Section 306 of PURPA

Dear Mr. Gray:

We are providing the attached comments regarding the DOE study. You may find them useful in developing a NARUC position.

Should you have any questions, please contact Charles Caprino at 203/566-2044.

Sincerely,

Department of Business Regulation
Division of Public Utility Control

C - C - P - Y

Henry Mierzwa
Executive Secretary

HM:CTC:sk

346
STATE OF CONNECTICUT
DEPARTMENT OF BUSINESS REGULATION
DIV. OF PUBLIC UTILITY CONTROL

DPUC COMMENTS - DOE GAS RATE DESIGN STUDY

As stated by ICF in the introduction, a number of important additions need to be made to the initial analysis in order to incorporate better information, and analyze various alternatives. Until such analysis is prepared, our comments concerning the ICF study must be considered preliminary. In the introduction, ICF notes that the approaches and methodologies incorporated in their report were described in previous reports and memorandum. We previously commented on certain observations concerning the ICF model. We find nothing in the January 10 Interim Report to alter our previous observations.

The ICF report states on Page II-4 that distributors tend to deliver higher quantities of gas under declining block rates than under other rate forms. Delivery by distributors of higher quantities of gas is not in of itself contrary to sound energy conservation but merely recognizes that as of a result of the many assumptions made by ICF, that the use of distributor facilities is increased under the declining block rate structure.

On Page C-3 (Appendix C), ICF presents its basis for developing the various rate structures. In its discussion of declining block rates, it is stated that the block structure is set to correspond to consumption of small, medium and large use customers. The unit charge for the third block (associated with service to large use customers) is based on unit costs associated with "volumetrically allocated costs". We find no reference to what is meant by "volumetrically allocated costs". If the term refers to pipeline commodity costs, we know of no instance in the natural gas industry where a declining block rate structure sets the tail block for residential customers at a level equal to or below pipeline commodity.

Our concern with respect to the development of the rate structures as presented in the ICF report is verified when we examine the rate structures set forth in Table II-2. In this table, we find that customer charge for "Distributor A" amounts to \$7.11 per month, "Distributor B" \$4.18 per month and "Distributor C" \$2.93 per month. We know of no reasons where cost based customer charge would differ substantially between individual utilities or between utilities in different areas of the country.

DOE Gas Rate Design Study
Page Two

In examining the rates for firm industrial customers set forth on Table II-3, we find further evidence that the rate structure suggested by ICF is contrary to normal rate making practice. The customer charge in "the flat rate with customer charge" for industrial service is less than \$1.00 higher than the customer charge for service to residential customers. We know of few instances where firm industrial rate structure does not have either a substantially higher monthly customer charge than the residential customer charge or where substantial monthly and/or annual minimum bills are required.

We note that in the design of the declining block rate for the residential customers, the ICF suggested tail block is less than the cost of gas shown on Table II-1 and the pipeline commodity costs set forth in II-9. We know of no gas distribution company which charges firm and/or interruptible service at a level less than the average commodity cost of the pipeline serving the customer.

On page II-12, ICF states that "conservation is measured in terms of the changes in the average consumption of individual customers". ICF continues that "as prices rise to the various classes, there is a decline on average in the use of gas by each customer. This represents conservation, either in the form of such short-term actions as turning down thermostats, or long-term changes like an investment in insulation, clock thermostats, heat pumps or more efficient furnaces or boilers." This statement indicates that included in the conservation effect, as measured by ICF, is the influence of the transfer of customers to alternative fuel sources. This makes absolutely no sense. In ICF's presentation, conservation is measured on the basis of averages. This is misleading since, to the extent fuel switching is present, depending upon rate form analyzed and the assumptions in the model, existing larger use customers may switch to alternative fuels and/or fewer large use customers would be added. For example, large use customers might be defined to include consumption over 100 Mcf per year. If fewer new customers in excess of 150 Mcf per year take service or existing customers in excess of 150 Mcf decide to switch to alternative fuels, the average consumption per customer in 1979 will be greater than average in 1990. Based on ICF's analysis one concludes that there has been conservation, when in fact the average use per customer who remains on the system may have increased. It makes no sense to conclude that on a relative basis, one rate form has merits in conserving natural gas, when this rate form may result in customers leaving the system. It makes no sense to conclude that in the interest of conservation, that an inverted rate form is the most beneficial to achieve conservation if large use customers no longer take gas service but replace gas furnaces with oil fired furnaces.

We note that on Page II-16 or as the Summary (Table V-1) shows the declining block structure produces a lower overall load factor than other rate forms. Yet the study shows the declining block rate to have the least influence on conservation. This does not make sense. Normally, as conservation of energy increases, load factor tends to decline.

We see major problems with the ICF model based on our brief analysis and interim report. In addition, we feel that the interim report dated January 10 on the simulation of seven rate forms contains several unresolved questions which can have a significant impact on the results presented. The rate forms suggested to be evaluated are not consistent with rate forms actually in use and are not based on standard rate design practices. More importantly the conclusions that can be reached as a result of the study are based on averages which do not reflect and tend to mask the basic measures which are intended to be evaluated.

PACIFIC GAS AND ELECTRIC COMPANY

77 BEALE STREET • SAN FRANCISCO, CALIFORNIA 94106 • (415) 781-4200 • TW 5-1111

February 27, 1980

Dr. Steven Skjei
 Economic Regulatory Administration
 U.S. Department of Energy
 2000 M Street, NW
 Washington, D.C. 20461

792215A

Dear Steve:

In response to your memorandum requesting comments on the Fifth Interim Report for the Gas Utility Rate Design Study, Pacific Gas and Electric Company (PGandE) has prepared the following critical analysis of the study. Specifically, responses have been developed for your "Questions for Reviewer Comment".

Before turning to the detailed comments, I would first like to address an issue that has been of concern to many policy-makers in the gas utility industry -- how the results of the study are to be used. It is currently our understanding that the study will not produce recommendations for nationally-designed rates. Rather, the model will only be used to gain qualitative insight into the effects of various pricing and ratemaking strategies. If this impression is correct, then PGandE concurs with this proposed use of the model. Upon review of the model, it is our belief that the model is incapable of testing the impact of policies, supply allocation or rate reform for individual utilities. Thus, the results of model should only be used for the most general types of policy analyses.

PGandE's responses to your questions are as follows:

1. Are the rate structures and levels as simulated appropriate and reasonable?

The structures as modeled seem to be correct. However, the rate levels seem to be somewhat high when compared to Gas Facts data. For example, for residential customers in the North-east, the model cites an average of \$4.69 per dth for 1979 (in 1978 dollars). While Gas Facts data are not available for 1979, assuming a 20 percent Increase over 1978, the 1979 average would be \$4.12 per dth.

Dr. Steven Skjei

February 27, 1980

2. Do the supply scenarios capture an appropriate range of supply costs?

There is inadequate documentation in the Fifth Interim Report to evaluate the assumptions underlying the supply scenarios. It is methodologically correct to tie cost increases in gas to fuel oil price increases, and hopefully the increases assumed for oil are correctly modeled.

One problem is in making uniform among all distributors the mix of gas supplies. For example, California utilities rely on high-priced Canadian gas while utilities in other regions do not. The model is unable to capture what is a very significant difference in purchase prices.

3. Are customer class price responses reasonable?

For the most part, customers appear to respond appropriately to price increases. However, the model's calculation of elasticities tends to yield higher short run and lower long run estimates than those of comparable studies (see page B-6). Thus, while the direction of the class response is correct, the magnitude of the response may be in error. Some sensitivity analysis should be performed to assess the impact of these differing estimates of elasticities..

Although the price responses are reasonable, there is some concern that customer response is not adequately modeled. In particular, conservation is not modeled in a comprehensive way. Long-run elasticity estimates alone are not sufficient to reflect structural changes such as: change in appliance stocks; response to federal and state mandated conservation programs; moratoriums on attachments; and long run changes in behavior.

4. Are characteristics of the simulated distributors reasonable and appropriate?

Much of the individual utility detail is lost in any regional or national model, and this model is no exception. In this case, the varying characteristics of utilities that, combined, sold 42 percent of all gas in 1978 are generalized to a few characteristics. For example, the split among residential, commercial, and industrial customers in 1978 varied significantly by region and within region. Yet some average splits were assigned. In the Northeast states, industrial sales ranged from 16 percent to 44 percent of total sales and in the Pacific Southwest states, industrial sales ranged from 43 to 64 percent of the total. Because the split among customers affects the calculation of annual load factor and required storage, it may be misleading to use an average for such a key characteristic as customer split.

Dr. Steven Skjei

February 27, 1980

Moreover, PGandE is concerned that the study fails to model the characteristics of a combination electric and gas utility or a distributor who also has a transmission system. Furthermore, PGandE views year-to-year optimization rather than planning period optimization as an irrelevant methodology, at least for this system. Most utilities with any transmission operation will certainly minimize costs over the planning horizon and not year-by-year. All of the aforementioned characteristics are key to the operating decisions made by the distribution company and should not be ignored.

5. Which additional rate forms should be examined?

To the extent that the study concludes that "the most important difference among distributors in the way they react to rate forms is the aggregate amount of distribution cost per unit of gas delivered" (page V-2), the impact of different rate forms is less important to explore. However, PGandE would agree that examination of marginal cost-based rates and lifeline rates would be useful.

As I stated earlier, PGandE believes that this model may be useful for gaining general qualitative insights into gas rate design. In that capacity, it is our hope that the comments offered herein will prove helpful as the model is further refined. If you have any questions or wish to discuss this matter further, please contact me at (415) 781-4211 (x1062).

Sincerely,

A. W. BERINGSMITH

MEMORANDUM

February 20, 1980

To: Heber P. Hardy, Chairman

792216A

From: Bob Silva

Subject: Review of Department of Energy Utility Rate Design Study
required under Section 306 of PURPA

I have reviewed the subject data and, with regard to comments on the five questions for reviewer comment, I would offer the following:

Question #1 - Are the rate structures and levels for each rate form as simulated appropriate and reasonable?

Proposed Answer:

Within the constraints and assumptions utilized under this model, I would indicate yes, with qualifications. First, I would qualify the response on the basis that the seven rate forms simulated (flat with customer charge, flat without customer charge, declining block, inverted rates, seasonal, volumetric and incremental pricing) utilize embedded or average historical costs to develop the rate levels in each scenario. Notwithstanding the "incremental pricing" rate form which attempts to price to non-exempt industrial boiler fuel users (Phase I of NGPA) on a "marginal cost" basis utilizing alternate fuel price ceilings as a "cap", the rate levels to all customer classes do not reflect the "true" (from an economic efficiency encouragement standpoint) costs of gas. The development of the "marginal cost" pricing scenarios are to be discussed and reviewed in a subsequent paper dealing with this subject. The second qualification deals with what is meant by ... "appropriate and reasonable." Under Title III - Retail Policies for Natural Gas Utilities, Section 301 (PURPA) the purposes are to encourage: (1) conservation of energy supplied by gas utilities; (2) the optimization of the efficiency of use of facilities and resources by gas utility systems; and (3) equitable rates to gas consumers of natural gas. Also, the Natural Gas Policy Act of 1978 (NGPA) and, more specifically, the Incremental Pricing Provisions of the NGPA tend towards insulating the residential customer class of customers from wellhead gas price increases by shifting these costs to the larger commercial and industrial boiler fuel users who are non-exempt (under Phase I) through a surcharge mechanism (effective January 18, 1980) without regard to class cost of service implications which may, depending upon methodology for allocating demand costs, support higher rates to the residential class of customer. Therefore, if the NGPA is the primary determinant of what is "appropriate and reasonable", the subject report appears to meet this criteria, along with study areas discussed under Section 306 of PURPA.

February 20, 1980
Page 2

Question #2 - Do the supply scenarios capture an appropriate range for future supply costs?

Proposed Answer:

Yes, it would appear that existing and future supply scenarios are reasonable. (This response is based in part on reports from Resource Planning Associates..."The Supply and Demand for Natural Gas in Nevada", and H. Zinder and Associates..."Northern Nevada Load Forecast Model").

Question #3 - Are customer class price responses reasonable?

Proposed Answer:

Yes, as far as short-term demand is concerned with regard to non-residential customer classes because of demonstrated elasticity positively correlated with price. It is difficult to assess short-term price elasticity of demand, let alone long term, for the residential sector because of economic inability to shift to alternatives. However, it would be safe to assume, in my opinion, that at some price or rate level the residential customer will make an economic decision to use less or shift to alternatives.

Question #4 - Are the characteristics of the simulated distributors reasonable and appropriate?

Proposed Answer:

They appear to be reasonable and appropriate when viewed from a national perspective and within the constraints and assumptions built into the simulation model. However, as has been demonstrated recently in hearings involving Southwest Gas Corporation, self-help measures and local supply scenarios affect both pricing and structuring of rates.

Question #5 - Which additional rate forms should be examined?

Proposed Answer:

Priority pricing concept tied to curtailment priorities using both cost of service (historical and marginal) and value of service concepts.

BS:dw

COLUMBIA GAS DISTRIBUTION COMPANIES

99 NORTH FRONT STREET

COLUMBUS, OHIO 43215

THOMAS E. MORRIS
SECRETARY AND GENERAL COUNSEL

February 28, 1980

792217A

Mr. Stephen S. Skjei
Chief, Regulatory Support and
Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
United States Department of Energy
Washington, D.C. 20461

Dear Mr. Skjei:

Re: Fifth Interim Report for the
Gas Utility Rate Design Study
Docket No. ERA-R-79-22

By memorandum dated January 11, 1980, under your signature, a copy of the above-referenced document was forwarded to the undersigned. The documents are quite complex, and our review process has taken longer than initially anticipated.

As a point of departure, Columbia reiterates the concern stated in written comments dated November 26, 1979, under my signature concerning the Fourth Interim Report, that the E.R.A. must recognize the inappropriateness of seeking uniform adoption of any of the proposed reforms due to the fragmented and highly individualized nature of the gas industry. Also, Columbia reaffirms its need and desire to be afforded the opportunity to use the model and observe its response to alternative inputs in order to effectively evaluate the model's validity. We believe that complete public participation in this study cannot be achieved pursuant to §306(d) of the Act unless full disclosure of all study components is made in time to allow reaction prior to finalization of the study by May 9, 1980.

I now address the specific questions contained in your memorandum referenced above.

Mr. Stephen S. Skjei

February 28, 1980

1. Are the rate structures and levels for each rate form as simulated appropriate and reasonable?

This question may be answered with a qualified "yes". The qualification lies in the urgency for recognition that the conclusions drawn from this model's application to three hypothetical utilities cannot and must not be applied to an actual gas distribution utility, since the factors used in the study do not reflect the operational characteristics of any actual distribution company.

2. Do the supply scenarios capture an appropriate range of future supply costs?

The alternative supply scenarios would seem to cover an appropriate range of circumstances. Nonetheless, caution is again in order. Columbia could pose any number of alternative supply scenarios, due to the unpredictability of future oil prices, and sketchy information on supplier rate design and other factors.

3. Are customer class price responses reasonable?

An answer to this question may be premature in light of the fact that further investigation of industrial conservation and fuel switching decisions as well as residential demand response to price changes is scheduled. Columbia believes that it is important to recognize that, in the industrial sector, the fuel-switching decision may well occur below the alternate fuel price, even in "firm load" situations, if for no other reason but to avoid the substantial regulatory burdens and uncertainties associated with incremental pricing.

4. Are the characteristics of the simulated distribution companies reasonable and appropriate?

Columbia's answer to question 1, supra, is appropriate here as well. The reasonableness of the characteristics of these hypothetical utilities is a function of the conclusions sought to be drawn from the model. If the study is intended to evaluate rate designs on a national basis, significantly more hypothetical cases should be employed.

5. Which additional rate forms should be examined?

Columbia agrees with the American Gas Association that, while sufficient rate forms have been considered by the study, some variation in the philosophy of determining block differential charges would be appropriate.

Mr. Stephen S. Skjei

February 28, 1980

Columbia again notes its willingness to meet with representatives of DOE and/or ICF, Inc. to further discuss the study to date, and work with you in any manner which would be helpful.

Very truly yours,

A handwritten signature in dark ink, appearing to read "T. E. Morgan", with a horizontal line extending from the top left of the first letter.

Thomas E. Morgan

COMMENTS
ON
"METHODOLOGY FOR ASSESSING THE IMPACTS
OF ALTERNATIVE RATE DESIGNS ON
INDUSTRIAL ENERGY USE"

792218A

COLUMBIA GAS DISTRIBUTION COMPANIES

88 NORTH FRONT STREET

COLUMBUS, OHIO 43215

March 17, 1980

Mr. Stephen S. Skjei
Chief, Regulatory Support and
Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
United States Department of Energy
Washington, D.C. 20461

Re: Sixth Interim Report for the
Gas Utility Rate Design Study

Dear Mr. Skjei:

By memorandum dated February 21, 1980 under your signature, a copy of the above-referenced document was forwarded to the undersigned. I make the following observations concerning the document entitled "Methodology for Assessing the Impacts of Alternative Rate Designs on Industrial Energy Use," prepared for DOE by Energy and Environmental Analysis, Inc.

1. This report does not suggest any mode for incorporation of its findings into the rate design model, or even if its findings should be reflected in the model.
2. The study provides insufficient data concerning the combustors of the 27 hypothetical plants (size, burner configuration, hourly fuel consumption, type of equipment) to allow for technical evaluation of its conclusions.
3. The study apparently assumes that firm load customers are not currently fitted out for alternate fuel capability. In fact, a number of our firm load customers have alternate fuel capability due to the recent history of seasonal curtailment and volumetric allocations on the Columbia Gas System. For such customers, no appreciable capital cost attaches to the decision to switch fuels.
4. The study is structured pursuant to the assumption that fuel price is the only factor in the decision to switch to alternate fuels. However, a number of factors may bear on this decision, including a history of interruptions in even firm service in the recent past, or apprehension concerning the probability of future interruptions.

Mr. Stephen S. Skjei

March 17, 1980

5. Just as the study erroneously isolates price as the only consideration in the fuel switching decision, so too it ignores the existence of numerous alternatives to fuel switching or conservation. For example, the industrial customer may decide to adopt an alternative technology which may or may not be more efficient. He may decide to purchase components rather than fabricate them, or cease operations altogether.

6. The study does not consider propane as an alternative fuel; we believe it should be so considered.

Columbia reiterates its desire for continued dialogue in this matter, and its willingness to assist you in any way possible.

Very truly yours,

Thomas E. Morgan
General Counsel

cc: W. R. Barnes
T. C. Brown, Jr.
J. T. Frost
W. W. Beauchais
R. E. McVey
R. F. James
W. L. Payne

COMMENTS
ON
"SIMULATION OF MARGINAL COST-BASED
NATURAL GAS RATES"

JOHN K. KEANE, JR.
DONALD F. ROGERS
SANDRA MINCH NODES
GREGORY V. CARMEAN

792219A

OFFICE OF PEOPLE'S COUNSEL
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231 EAST BALTIMORE STREET
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March 24, 1980

Stephen S. Skjei, Chief
Regulatory Support and Assistance Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D. C. 20461

RE: Seventh Interim Report for the
Gas Utility Rate Design Study

Dear Mr. Skjei:

Find enclosed ten (10) copies of our comments upon the Seventh Interim Report. The detailed, intricate model which is a substantial part of the study carries with it a risk that examination of each branch of every tree will limit the debate to the tempest among technicians.

Moving rates over time toward avoidable costs will continually improve rates, and at each step of the way better achieve energy conservation, efficient use of capital and equity. As the study moves forward we hope that continuous rate improvement is the broad policy objective.

Sincerely,

John K. Keane, Jr.
People's Counsel

JKK/et
Enclosure

STATE OF MARYLAND

JOHN E. KEANE, JR.
DONALD F. ROGERS
PHILIP S. SHAPIRO
SANDRA MINCH NODEN
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March 24, 1980

COMMENTS ON THE SEVENTH INTERIM REPORT FOR THE
GAS UTILITY RATE DESIGN STUDY

The Seventh Interim Report was accompanied by the text of a speech February 13, 1980 given by Stephen A. Skjei in which there was relevant discussion of marginal cost based retail gas rates. Since the speech contains many worthwhile comments and views not expressed in the Interim Report, the following discussion will refer to and discuss both documents.

As a general observation, the documents reflect a good beginning to the development of marginal cost based rates, but they give little indication as to DOE's probable resolution of the problems involved in the development of such rates. The Division of Utility Systems is obviously aware of the general theoretical nature of the discussion and is presumably seeking more detailed analysis and development from the contractor. Accordingly, the following observations will also be in the nature of a general discussion of the theoretical and practical problems raised by the Interim Report.

Overview

The Interim Report and the speech give prominent consideration

to the actual design of rates based on those costs or upon marginal cost principles. Nonetheless the three rate forms proposed are appropriate and should provide the analysis upon which individual rate design standards can be evaluated.

However, the discussion of the necessary adjustment of rates to conform with the cost-of-service revenue requirement of distribution companies is substantially less adequate. According to the Interim Report, two approaches will be used. The first approach will simply price the product at the full marginal cost, on the assumption that "some mechanism" will be designed that will conform the total revenues to the revenue requirement, but that will not affect the marginal blocks. This approach is unrealistic on a theoretical and a practical basis. First, realistically, neither Congress nor any state commission will be seriously interested in full marginal cost rates that depend on some taxing vehicle to recover the excess revenues from the company and return them to the ratepayer. Second, the simulation of a distribution company under such full marginal cost base rates will show changes in demand and supply that will never occur. In other words, running a rate that admittedly does not conform to the revenue requirement will produce irrelevant results as to demand and supply changes. This analysis should take into account the necessary adjustments and compromises that must be made to design rates to meet the revenue requirement.

The second approach to adjustment is somewhat unclear. It is described as "actually inverting the rate schedule." According to the Interim Report, the simulations run on these adjusted rates will simply "illustrate the effects of the inability to design class rate structures that exactly reflect marginal costs to all individuals while simultaneously adjusting to meet the revenue requirement."

These simulations would thus simply develop a tautology on the widely-recognized notion that one cannot design class rate structure equal to marginal costs—and simultaneously meet a revenue requirement. Perhaps a description of the second approach does not reflect the intent of the author, but as written it proves little of value in analyzing the development of marginal cost based rates; or in analyzing market and customer impacts of moving rates over time toward avoidable costs.

Marginal Commodity Costs

It is in the determination of commodity costs that Mr. Skjei's speech provides more assistance than the Interim Report. The Interim Report has made a single macro-economist's determination that the appropriate marginal cost of gas is the long run market value or opportunity cost. It then seeks to identify the operation of those costs according to natural gas availability.

Both the speech and the Report assume that the only alternate fuel to natural gas is oil. While that may be true for some users, particularly those in some industrial and boiler applications, it is certainly not true in residential, commercial and other industrial applications. Residential and commercial generally have a short-run fuel elasticity with higher-cost supplies of natural gas (they can cut or increase consumption) and long-run appliance elasticity, and that is with electricity. Even though there are fuel elasticities in the short run with those certain industrial customers, in the intermediate or long run, even they have clear appliance elasticities with electricity, and in some parts of the country, coal. Whether the

electric company is using coal or nuclear power for its incremental fuel supplies, their commodity rates are, under any world energy scenario, going to remain substantially below world oil prices. It is in this way that both the Report and the speech wholly disregard a major element of the competition for natural gas.

The residential and commercial gas user generally have no alternative fuel in the short run except gas with different costs and for a longer horizon the alternative fuel would not be oil, but electricity. There is no question that the substitutability between oil and gas is a major concern to the Department of Energy in its national energy policy matters, but state regulatory commissions and most consumers, although they are concerned with oil imports, do not view oil as an alternative fuel either in the short or long run.

Secondly, the use of oil at world prices as the opportunity cost will render moot any practical application of marginal costs for regulated utility rates. If natural gas is priced at such an amount, the revenues covered by a distribution company will probably so vastly exceed the revenue requirement as to eliminate any capacity charges. Moreover, at current world oil prices and prevailing natural gas prices, such revenues would be so great that for some companies there would be no customer charge, no demand charge and there would probably be a required reduction in the commodity rate to meet the revenue requirement.

Thirdly, even though the Report accurately notes that commodity costs are rising much faster than demand costs, there are important fluctuating demand costs on a distribution system, which generally vary over time. The difference in costs between on-peak and off-peak is quite substantial and should receive some, if not total, reflection in the rates. Without some demand charge, customers may well cut

back their consumption at low demand cost times while maintaining their consumption at high demand cost times, thus artificially increasing distribution demand costs.

Both the Report and the speech are properly concerned with the length of the planning horizon in the determination of marginal costs. The continuation of NGPA price controls until 1985 and the deregulation of substantial portions of gas after that time, give a difficult picture for appropriate determination of marginal costs. However, such inquiry does not give appropriate consideration to the effect of marginal costs prices on distribution companies. For the present time, and at least until 1985, if the political treatment of natural gas prices does not change, gas distribution companies are paying the regulated prices under the NGPA.

Accordingly, we would strongly urge the Study to give serious consideration to marginal costs based on distributors' costs so that the results of the Study and any national standards adopted by Congress, could readily be translated into rate design changes by state commissions. Stabilization of earnings at a reasonable level is an appropriate goal of marginal cost pricing and one of great concern to regulatory commissions. Although it may not be the most prominent goal of the Department of Energy, it will be a major consideration in each state gas rate case.

There is an alternative basis for estimating marginal commodity costs that is not addressed by either the speech or the Report. From the distributor's point of view, its costs vary over time and can be estimated at a composite of daily weighted average marginal supply costs (NGPA gas, LNG, Propane Air, SNG). A slightly longer

planning horizon would result in including Canadian and Mexican gas in the mix; including some avoidable costs. This estimation technique is similar to utilizing system lambda as the marginal energy cost for an electric utility. We are unaware of no marginal cost techniques that identify world oil prices as the relevant marginal cost of electric energy.

NGPA Incremental Pricing

At this writing, FERC has not issued its rules for Phase II of NGPA incremental pricing. The 7th. Interim Reports observes that NGPA incremental pricing provides conservation incentives for industrial customers but at the same time creates disincentives for exempt customers. This phenomenon will occur in scattergun fashion if FERC permits statewide exemptions from NGPA incremental pricing. Some states have already issued orders pricing non-exempt users at the alternative fuel price; thereby zeroing reportable MSAC for the state's distributors. Within each such state, the effects upon non-exempt users vary widely from distributor to distributor. The customers of the distributor with no non-exempt load will promptly face NGPA prices as they are rolled in. On the other hand, customers of distributors with substantial non-exempt load will face greatly reduced rates. This not only will create conservation disincentives among exempt customers, but also provides incentive for pipelines to bid up the price of gas beyond market clearing levels. The FERC Rulemaking on statewide exemptions is under weigh. It will impact upon rate design to a significant degree and will also affect market penetration over the next five (5) years.

Lessons Learned from Electric Pricing

Over the past decade the marginal cost debate has taken place in the electric arena. A broad, and perhaps informal, consensus has been reached. For example, there is general recognition that marginal costs are relevant, that LRIC is a reasonable measure of marginal cost; that costs vary over time; that rates can rarely if ever be set equal to marginal costs; that state regulators are concerned about impacts of rate design changes; that movement of rates in the direction of rates based on marginal costs principles can be achieved without abrupt impacts; and that state regulators are not likely to vary widely from traditional means of determining class revenue requirements; and that avoidable costs can and should be reflected in rates. One thus sees the Lilco "2/3" rule; or 10% limitations on rate increases occasioned by change in rate design for a significant number of customers; or PSC statements that implementation of time differentiated rates will occur over time beginning with some customers and adding others subsequently. In establishing time differentials (seasonal and daily) various measures of cost have been used, but where implementation has occurred, the measure utilized is reflective of that measure which results in the lesser impact. For example, internal running rates may be measured rather than opportunity costs.

In assessing gas distributor rates it would seem wholly worthwhile to study rates predicated upon similar assumptions about implementation.

Consumer Information and Blocking

If rate design changes are in order, it is vital that the new rates can be easily understood by consumers and that the rates are communicated to consumers. Consumers see unit pricing information in the super-markets, but their utility bills do not contain sufficient information to enable people to figure out what buying more or less energy means. Rates should be clearly stated on the utility bill.

If the rates are so stated and are in an understandable form, people are much more likely to make the right decision, from both their personal point of view and from the public interest point of view. To the extent that blocking in the rates is more difficult to understand, judgments should be resolved in favor of eliminating or minimizing blocking.

In the 1920's when declining blocks first appeared, the blocks were few in number and declined gently. The literature of that era indicates, at least in the beginning, that the blocking was such that most customer's usage terminated in the tail block. Over time of course that feature completely disappeared as rate schedules were developed by engineers to reflect various accounting sums. If past is prologue, there is considerable risk that well intended rate inversion will ultimately result in several sets of ascending blocks for any number of wrong reasons. The Seventh Interim Report makes the observation that under its marginal cost rates that usage termination occurs before the tail block for many customers. In evaluating the results produced by the model for that set of inverted rates, DOE should carefully consider consumer information, public understanding and the risk of subsequent inartful blocking in addition to the considerations mentioned in both the speech and the Seventh Interim Repo

Other Considerations

In many markets, consumers today can convert to gas for space and water heating and more than recapture their capital costs between now and 1985. Retail pricing policies that differ from those implicit in the NGPA incremental pricing scenario, would prohibit conversions. This should be considered. In addition, as a matter of policy one should recall that the gas industry currently provides about 25% of our nation's energy. It is possible in the mid-term (to the year 2000) for that same market level to obtain if unconventional sources, biomass, and other sources are developed. As a policy matter, if that market level is desirable, economic, or both, then distributor rate design should be consistent with that objective. Stated another way, rates in the near term (thru 1985) should not be designed in a manner that gives rise to a mid-term demand scenario likely to reduce the gas market substantially below that level.

Rates for new gas customers need also be considered. Does a new customer pay none of the distribution costs? Does he pay all or part? Are they paid up front or amortized? There are substantial equity considerations here together with very different demands for gas supplies, as well as different market mixes for gas and electricity. None of the rate forms studied appear to have varied tariffs applicable to extensions of mains and service laterals. These tariffs can have a very substantial impact upon market penetration for gas and electricity.

Summary

The revenue constraint augurs against price being set at marginal cost. To the extent that avoidable costs can maximally be reflected in rates the conservation and efficiency objectives of the NEA can best be achieved. The equity objective should be afforded greater weight in the study, both as a matter of fairness and in recognition of state regulators' need to implement changes over time so as to minimize abrupt impact upon customers and earnings.

Respectfully submitted,

JOHN K. KEANE, JR.
PEOPLE'S COUNSEL
STATE OF MARYLAND

UNITED STATES OF AMERICA
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

In the Matter of:

Gas Utility Rate Design Study:)
Responsibilities Under Public) Docket No. ERA-R-79-22
Utility Regulatory Policies Act)
of 1978)

COMMENTS OF
THE PROCESS GAS CONSUMERS GROUP
AND THE GEORGIA INDUSTRIAL GAS GROUP
ON SEVENTH INTERIM REPORT ON MARGINAL COST PRICING

Pursuant to the March 6, 1980, Memorandum of Stephen S. Skjei of the Economic Regulatory Administration ("ERA"), The Process Gas Consumers Group ("PGC") and the Georgia Industrial Gas Group ("GIG") hereby respectfully submit their comments on the Seventh Interim Report for the Gas Utility Rate Design Study addressing marginal cost pricing.

I. STATEMENT OF INTEREST

PGC is an association organized to promote the development and adoption of coordinated, rational, and consistent federal and state policies which will assure an adequate and reliable supply of natural and manufactured gas at just and reasonable cost-based rates for industrial gas uses which

cannot technically or economically be converted to alternative fuels. The members of PGC participating in this proceeding are: American Can Company, Armco Inc., Bethlehem Steel Corporation, Cone Mills Corporation, General Motors Corporation, Libbey-Owens-Ford Company, Owens-Corning Fiberglass Corporation, Owens-Illinois, Inc., and United States Steel Corporation.

Joining with PGC for the specific purpose of participating in this proceeding are the following members of the Georgia Industrial Gas Group: American Industrial Clay Company of Sandersville, Anglo-American Clays Corporation, Freeport Kaolin Company, Georgia Kaolin Company, Griffin Pipe Products Company, and Thiele Kaolin Company. These companies all operate industrial facilities which consume natural gas in the State of Georgia. (General Motors, a member of PGC, is also a member of GIG.)

II. COMMENTS

The Seventh Interim Report, entitled "Simulation of Marginal Cost-Based Natural Gas Rates," begins with a discussion of the "Technical Staff Analysis" (hereinafter "DOE Analysis") submitted by the Department of Energy to the Federal Energy Regulatory Commission in connection with FERC's Phase II incremental pricing rulemaking. */ The DOE

*/ DOE, Technical Staff Analysis in Response to Notice of Proposed Rulemaking on Phase II of Incremental Pricing (Feb. 8, 1980).

Analysis states that an orderly transition to decontrol of natural gas prices under the Natural Gas Policy Act (not to occur until 1985 or later) is being complicated by the continuation of NGPA ceiling prices on all natural gas well below increasing world oil prices. (DOE Analysis at 1). This will result, according to DOE, in curtailments, economic inefficiency, disincentives to conserve, as well as in the misallocation of supplies between the intrastate and interstate markets and between different pipelines, both up to and after deregulation. (Id. at 1-2). The Seventh Interim Report discusses marginal cost pricing of natural gas by pipelines and distributors as a likely solution to "market ordering" problems identified in the DOE Analysis. It postulates that marginal cost pricing at the wholesale and retail levels would alleviate these distortions, although it acknowledges that there are difficult problems to be addressed in the design and implementation of rates based on marginal cost. (Report at 3). Indeed, the DOE Analysis acknowledges (at 1) that such pricing would require "a substantial change in the way pipelines and distributors do business".

As we understand it, marginal cost pricing is intended to simulate what would happen if there were a free market in natural gas. PGC and the Georgia Group respect-

fully submit that the much better solution is actually to establish a free market in natural gas -- i.e., to deregulate immediately the wellhead price of natural gas. If market distortions may be avoided only by pricing natural gas at its true economic cost or "opportunity cost", the most rational way to eliminate such distortions is to institute such pricing at the wellhead through a free market and to reflect such prices in retail rates through traditional ratemaking techniques. It is simply irrational and inefficient to remedy artificially low prices at the wellhead by ignoring the real problem and by artificially pegging retail rates at "marginal cost". As the DOE Analysis acknowledges: "higher oil prices make the decontrol of natural gas prices even more critical to achieving natural energy objectives." (Id. at 1).

Wellhead price deregulation would bring order to natural gas markets, because retail rates based on average cost ratemaking will move toward marginal cost under deregulation. The time required for rates to reflect new wellhead prices will depend upon the scope and speed of deregulation. No artificial attempt to simulate the free market, however, particularly not marginal cost pricing, can erase overnight the distorting effects of twenty-six years of misguided wellhead price regulation. If anything, wellhead deregulation will bring order to the market more quickly and effi-

ciently than utility rate reform, because it will eliminate five or more years of continued wellhead price regulation and distortion under the NGPA. The Seventh Interim Report states (at 5) that the rate design study will compare full decontrol of wellhead prices in 1980 to marginal cost pricing. PGC and the Georgia Group urge ERA to include such a comparison in its final study.

In addition to the fundamental problem noted above, there is a second unavoidable defect in marginal cost pricing. In brief, no matter how serious an effort has been made in the past to base rates on marginal cost or "opportunity cost", it has proved impossible in practice to achieve the economists' goal of assuring that each and every user in fact pay the marginal cost of providing service to him. What has resulted in practice, and what is sure to result from any future attempt to impose such pricing, is simply another version of incremental pricing, such as under Title II of the NGPA, under which costs are shifted to one customer class (usually industry) in order to subsidize other customer classes (usually residences and small customers).

Apart from the enormous definitional problems in determining what is and what is not a "marginal cost", apart from the necessary (but invalid) assumption that competing, substitutable goods are also priced at their marginal cost, and apart from the necessary (but, again, invalid) assumption

that consumers have perfect knowledge of their choices in the market, marginal cost pricing theory faces serious practical problems. Not the least of these problems is the fact that, by statute, a utility's revenue requirement is limited to its actual cost of service, including a reasonable return on rate base. Given this fact, it is simply not possible to establish a rate structure that charges each and every consumer a rate equal to marginal cost.

Assuming an era of rising costs, if all consumers were charged marginal costs, the utility would collect revenues substantially above its actual, incurred costs and would thus violate the statutory mandate that rates be "just and reasonable".

Various adjustments have been proposed to make marginal cost theory work in the real world, i.e., to adjust marginal cost rates so that they do not yield revenues to the utility in excess of its revenue requirement. These adjustments have included (1) returning the excess revenue to gas consumers on a per capita basis, (2) returning it to them on an individual percentage-of-consumption basis, (3) returning it to them on the basis of estimated individual elasticities of demand, and (4) even taxing it away for the benefit of all citizens, not just gas consumers. The rates which result after these patch-up adjustments have been made, however, deviate considerably from true marginal costs, substantially

compromise the marginal cost theory upon which they are supposed to be based, and are often discriminatory. Moreover, and perhaps most significantly, there is little to suggest that such compromised "marginal" rates convey "correct" price signals or allocate natural gas resources any better than average cost rates. */

Although most reform proposals purport to be cost-based, their implementation usually results in wide deviations from whatever cost standard is employed. To the extent that rates significantly depart from costs as the touchstone by which they are set, the ratemaking process becomes even more politicized and, indeed, akin to taxation. As a result, rates paid by some consumers will be greater than the cost to the utility of providing service to them, while rates paid by other consumers will be substantially less than the utility's cost of providing that service. The determination of who subsidizes whom will in turn depend, to a large extent, on the political judgment of regulators, as well as on the particular policy goals certain pricing techniques purport to encourage and regulators seek to advance. Such reforms may thus lead to significant income redistribution among and within customer classes and may provide regu-

*/ For example, the Seventh Interim Report postulates an approach wherein "total bills" would be adjusted "in a way that would not affect the marginal rate seen by customers." (Report at 12). It is difficult to conceive of any "adjustment" to a consumer's gas bill that would not be viewed by the consumer as a reduction in his overall or average rate below true marginal cost.

latory commissioners with virtually untrammelled discretion.

PGC and the Georgia Group urge ERA to reflect all these practical and equitable considerations in any final gas utility rate design study on marginal cost pricing.

III. CONCLUSION

The Process Gas Consumers Group and the Georgia Industrial Group appreciate this opportunity to comment on ERA's marginal cost pricing study and urge ERA to consider in its study: (1) wellhead price deregulation as a preferable alternative to marginal cost pricing and (2) the potential inequities, inefficiencies, and impracticality of implementing marginal cost pricing.

Respectfully submitted,

Edward J. Grenier, Jr.
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Glen S. Howard

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Attorneys for
The Process Gas Consumers Group
and the Georgia Industrial Gas Group

March 24, 1980

792221A

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

Gas Utility)
Rate Design Study)

Docket No. ERA R-79-22

SECOND SUPPLEMENTAL COMMENTS
OF
UNITED DISTRIBUTION COMPANIES

Pursuant to the memorandum of Dr. Stephen S. Skjei dated March 6, 1980, United Distribution Companies (herein called "UDC") submit these Second Supplemental Comments relative to the Gas Utility Rate Design Study being conducted by the Economic Regulatory Administration (herein called "ERA") pursuant to Section 306 of the Public Utility Regulatory Policies Act of 1978 (herein called "PURPA").

These Second Supplemental Comments address the seventh interim report of the ERA Staff attached to Dr. Skjei's memorandum and entitled "Simulation of Marginal Cost-Based Natural Gas Rates". Such report will be referred to as the; "Marginal Rate Draft" or "Draft".

For the reasons herein set forth, UDC, respectfully, recommends in particular:

- (1) that the criticisms of "average cost pricing" set forth on pages 2 and 3 of the Draft be modified and, in some cases deleted;
- (2) that the bold endorsements of marginal cost pricing set forth on page 3 of the Draft be severely modified and limited and, in some cases, withdrawn;
- (3) that the discussion of the accomodation of marginal pricing to overall cost-of-service as set forth on pages 11 and 12 be expanded, with the limiting effects on marginal pricing being fully disclosed; and
- (4) that the Report must disclose the major risks which are involved in this untried rate form.

In view of the extremely short period provided for response, these UDC Comments have been hastily prepared. It is, earnestly, hoped that they will be of benefit to ERA and its Staff in the preparation of this important report to Congress.

Filed: March 25, 1980

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I
IDENTIFICATION, INTEREST AND REPRESENTATION
OF
UNITED DISTRIBUTION COMPANIES.

Statements with respect to these subjects are set forth in UDC's original Comments filed July 2, 1979 and in its First Supplemental Comments filed February 25, 1980. The same are incorporated herein by reference.

II
INTRODUCTION.

As in the First Supplemental Comments, UDC again wishes to express to the ERA Staff its deep appreciation for the ongoing opportunities to comment on the various portions of this important Report to Congress, as they are in process of development.

These Comments make several far reaching proposals for the modification of the Draft, the limitation of its propositions and even for the deletion of certain concepts. It is hoped that these will be welcomed, for the subject is of extreme difficulty and complexity; and all are working in an untried field.

As mentioned on the cover, these comments have been hastily prepared because of necessary time constraints. They may, therefore, be supplemented upon further review.

III
SUMMARY STATEMENT RELATIVE TO THE
MARGINAL RATE DRAFT.

3.1 "THE MARKET ENVIRONMENT" (PAGES 1 - 3 OF THE DRAFT).

UDC strongly objects to the simplistic and categorical propositions that "average cost pricing" will occasion serious public detriments during the next several years and that these same problems would be overcome through the use of end user rates "tied directly to marginal wellhead costs".

On pages 2 and 3, the Marginal Rate Draft, without analysis and relying entirely on a DOE Technical Staff Analysis recently prepared for other purposes, categorically concludes that "average cost pricing" will "result" during the next several years in:

- (1) "supply/demand imbalances";
- (2) "misallocation" of supplies;
- (3) improper "shifting" of new gas between pipelines;
- (4) inadequate "incentives to conservation"; and
- (5) wellhead prices "above the long run market clearing price".

Then, it is categorically stated on page 3, without support, analysis or limitation of any kind, that, if rates at both the pipeline and distribution company level are "tied directly to marginal wellhead costs",

- (1) "the price for gas that is not subject to controls would be brought down to the long run market clearing price";
- (2) "there would be no shifts in volumes at the time of decontrol in 1985";
- (3) "available supplies would go to the most highly valued uses"; and
- (4) "all consumers would see strong and appropriate incentives for conservation".

These strong and unqualified criticisms of existing rate forms and equally strong and unqualified endorsements of new and untried rate forms are out of all proportion to the actual facts and are, in some instances, downright wrong. Placed in a Report to Congress, they can do untold harm to the consumer and public interests and to the gas industry which is obligated to serve those interests.

In the consumer and public interest, some of these criticisms and endorsements must be removed completely; and this critical section of ERA's Report must be modified and expanded in a fashion which will treat existing rates in a fair and proper fashion and place the potential benefits and detriments of untried marginal rates in proper perspective.

3.2 RATE DESIGN (PAGES 9 - 12 OF THE DRAFT).

At pages 11 and 12 the Marginal Rate Draft, all too briefly, turns to the problem of conforming marginal pricing to overall cost of service, undoubtedly the most difficult, limiting and critically important problem surrounding the use of this untried rate form. UDC, respectfully, submits that the treatment of this subject must be greatly expanded. The limitations which this problem places on the effects which can be achieved by marginal pricing must be explored, as must the difficulty of rate design and collection.

The Report to Congress must fairly disclose the nature and extent of this problem.

3.3 THE MAJOR RISKS ASSOCIATED WITH ANY NEW AND UNTRIED RATE DESIGN.

As set forth in UDC's First Supplemental Comments, the institution of any new and untried rate design, -- particularly on the catholic basis envisioned by the Marginal Rate Draft, -- involves major risks to the public service and to the consumer and public interest. Major shortfalls in revenue may occur and major services may be lost, with consequent increases in residential rates.

None of these risks are mentioned in the Draft; but it is imperative that they be made plain to Congress.

3.4 PROBLEMS OF COST CLASSIFICATION AND USER RESPONSE.

The difficult problem of cost assignment involved in marginal rates are discussed by the Marginal Rate Draft at pages 5 - 9; and UDC submits that this presentation must make plain the important differences between modeling this subject and the practical development and application of the same in real-life utility operation.

Furthermore, the Draft assumes that users will actually respond to these novel cost assignments as planned, -- with exact provision of necessary revenues and no harm to the public service. But the potential for damaging results is great; and the report to Congress should give plain warning of these possibilities.

3.5 PROBLEMS OF EQUITY AND CLASSIFICATION.

As discussed in the First Supplemental Comments of UDC, the injection of any new and untried rate into the rate design of a utility involves serious issues as to the reasonableness of the rate and the classification of users. The necessity for meeting these issues in a sound basis in each area of service is not discussed in the Draft; and this section of the Report be amplified accordingly.

IV

IN THE SECTION ENTITLED "THE MARKET ENVIRONMENT",
THE SEVERAL CRITICISMS OF "AVERAGE COST PRICING" AND
THE SEVERAL APPROBATIONS OF "MARGINAL COST RATES"
MUST BE GREATLY QUALIFIED AND LIMITED AND,
IN SOME CASES, REMOVED ENTIRELY.

4.1 INTRODUCTION.

The Marginal Rate Draft begins with a brief and categorical recitation of the public detriments which "can be expected to result" from the continued use of "average cost pricing"; and this is followed with the categorical and wholly unsupported statement that these several detriments would be prevented or rectified if end user rates were tied directly to marginal wellhead costs.

The conclusions as to the supposed detriments which will result from average cost pricing are predicated directly on the Technical Staff Analysis recently prepared by DOE's Office of Policy and Evaluation in connection with its study of incremental pricing under Section 202 of the Natural Gas Policy Act of 1978. The Marginal Rate Draft itself sets forth no analysis of this key subject, nor does it expose the pitfalls and limitations which surround these all important conclusions.

And the Marginal Cost Draft includes no support whatsoever for its conclusions that marginal cost rates can answer the problems. All that is said is merely this:

"The effective implementation of rates based on marginal costs can potentially contribute to alleviating some of the market problems described above. This would involve designing end user rates that are tied directly to marginal wellhead costs of gas as well as marginal transmission and distribution costs incurred in delivery of the gas. If such rates could be implemented at both the pipeline and distribution company level, the price for gas that is not subject to controls would be brought down to the long run market clearing price, there would be no shifts in volumes at the time of decontrol in 1985, available supplies would go to the most highly valued uses, and all consumers would see strong and appropriate incentives for conservation."

"Average cost pricing" does not so clearly "result" in the evils which are so briefly presented; and, indeed, such pricing may not result in any of the harms so laid forth. Nor does "marginal cost pricing" so clearly provide the desired answers; and, indeed, it may fall far short of providing any one of them.

On these all important issues, the Draft does not, and cannot constitute a fair and sound Report to Congress.

**4.2 FUNDAMENTAL LIMITATIONS WHICH RESULT FROM
THE FACT THAT PIPELINES AND DISTRIBUTORS ARE
FULLY REGULATED ON A COST OF SERVICE BASIS.**

Before turning to the several conclusions set forth in the Draft, it seems necessary to emphasize, as UDC did in its First Supplemental Comments, the very grave market limitations which are necessarily presented by cost regulation.

It is always appealing to view "marginal pricing" from the standpoint of pure economic principle and to say that, if a particular end user is faced with a rate based on marginal cost, he will react in such and such a fashion. But the problem is that, if the rate for part of the service of the pipeline or distributor is based on marginal cost, the rates for the remainder of the service are forced below "rolled-in" or "average costs". As to this latter part of the service, end users cannot possibly see marginal costs. As to this service or these services they will necessarily see only embedded costs; and they will not have the desired economic reaction.

In cost based regulation, expected revenues from rates must be balanced with test period cost-of-service; and, if rates from some services are increased to reflect marginal costs, other rates must be correspondingly reduced.

There is absolutely no way in which the industry or ERA or Congress can get around this fundamental problem, unless the whole system of federal and state regulation on an overall cost basis is abandoned; -- with gas utility service being placed in the same free economic environment as coal and, hopefully, oil.

**4.3 THE DRAFT'S PROPOSITION THAT "SUPPLY/DEMAND IMBALANCES"
WILL RESULT FROM "AVERAGE COST PRICING" AND THAT
THESE IMBALANCES WILL BE ELIMINATED BY "MARGINAL COST PRICING".**

It is categorically stated on page 2 that "average cost pricing" will result in "supply/demand imbalances" during the next few years; and on page 3 it is said that this problem will be cured if pipeline and distribution rates are tied to "marginal wellhead costs".

We assume this means that demands for gas will be too high if average cost pricing is used but balanced with supply if marginal rates are used.

But this attack on "average cost pricing" coupled with the approbation of "marginal cost pricing" is neither justified nor proper.

The real question is whether overall end user demands for gas will be reduced over the next few years if "marginal cost rates" are substituted for "average cost pricing". And, of course, this would be the case if all gas service were priced at the latest marginal wellhead cost, just as OPEC oil imports are priced at latest cost.

But, in the gas industry, this cannot be the case. If some service is priced at marginal cost then the remaining service must be priced at less than average cost -- for, as pointed out above, overall revenues must be held to overall cost.

Thus, if all industrial rates are priced at marginal wellhead costs, residential and commercial rates will be held far below average cost. Since all gas service is price elastic, any conservation by industrial users will be offset by added requirements by residential and commercial users.

So too, if all end users are priced at "marginal costs" for part of their service, the rates for the balance of their service will be less than "average cost"; and the cost of the overall service will necessarily remain the same.

Added conservation, if it comes at all, will only come if and to the extent that end users are influenced by a high tail block rate. This may or may not be effective as an inducement. It is highly questionable in cases in which end users are billed on a budget basis, as more and more prefer to be. Likewise it is questionable in any commercial and industrial process where overall costs of fuel determine the user's decision as to both fuel selection and conservation facilities.

The uncertainties are great, particularly where, as here, the rate form has not been in use. Marginal pricing may be a fine economic theory; but it has not been widely used in utility practice and most experience has occurred in connection with new services -- as in the case of promotional electric rates for water and space heating.

There are almost no case histories -- certainly none on a broad industry-wide scale; and there is absolutely no basis for any glowing conclusion -- such as appears in the Draft -- that "marginal cost pricing" in the gas industry will greatly increase conservation of gas use and offset any supply/demand imbalance.

It must be remembered that great strides in gas conservation have already occurred and are continuing to occur, in all classes of use, under rolled-in or average cost pricing. As pointed out above, overall rates must be limited to overall cost of service; and, if marginal rates are instituted, they must be balanced by rates for other services which are less than those predicated on average cost pricing. To say that greater conservation will result from these new and untried rate forms is only the wildest kind of guess; and ERA's Report must frankly so state.

Furthermore, the unknown course of producer drilling between now and 1985 will have far greater effect on the then supply/demand balance than any net change in demand which might arise from the institution of marginal pricing. Producers will be motivated to drill or not drill by factors far more important than those resultant from the mere institution of marginal pricing in lieu of average pricing for a part of the overall gas service; and ERA has no way of predicting how supply and demand will balance in 1985.

For the ERA Report to say, as it now does on pages 2 and 3 that marginal cost pricing will offset any supply/demand imbalance is wholly unrealistic and patent overselling, against the public interest.

UDC, respectfully, submits that, if a supply/demand imbalance is to be discussed, the ERA Report must:

- (1) attribute the supply/demand imbalance to the real source from which it stems: Federal wellhead price controls;
- (2) fairly portray the major strides in conservation being accomplished under existing rate structures; and
- (3) point out that improvements in conservation through the institution of marginal cost rates would be uncertain at best.

4.4 THE DRAFT'S PROPOSITION THAT "AVERAGE COST PRICING" RESULTS IN A "MISALLOCATION" OF SUPPLIES TO LOW VALUED USES AND THAT UNDER "MARGINAL COST PRICING" AVAILABLE SUPPLIES WOULD GO TO THE MOST HIGHLY VALUED USES.

The Marginal Rate Draft on pages 2 and 3 contends that "excess of demand" occurs from "average cost pricing" and then argues that, since this alleged "demand excess" will differ from system to system,

"some systems will be able to serve a broader range of consumers than other systems and gas will not get uniformly allocated to the highest valued uses across the entire market."

Then, on page 3, the Marginal Rate Draft baldly states that, with "marginal cost pricing" -

"available supplies would go to the most highly valued uses."

There is absolutely no basis whatsoever for this proposition; and it should be completely withdrawn from the ERA Report.

It is, of course, true that utility services vary widely throughout the United States, according to the nature of service areas, the kinds and amounts of industrial use, the underlying pipeline supplies and the amounts of LNG, SNG, local production and storage constituting part of the distribution utility supply. Many utilities serve low priority users, others do not.

But it is a thesis of the Technical Staff Analysis of DOE's Office of Policy and Evaluation that "available supplies" should be so allocated among systems that gas usage will be uniform nationally; and this necessarily means the elimination of certain low priority users on some systems to free up gas for higher priority users on others. The Marginal Rate Draft has been caught up in this fever.

There are three grave problems with this whole concept:

In the first place, "marginal cost pricing" will probably not bring about this result. Let us suppose for purposes of discussion that industrial uses are subjected to gas rates predicated on marginal wellhead costs as proposed. Will these rates force the industrial users to abandon gas service and flee to oil or electricity -- thereby releasing the gas for distribution to high priority users on other systems? Certainly this will never happen unless the marginal gas rates will be greater than the cost of alternate service; and, given the current and expected future trends in oil prices and electric rates, there is no assurance whatsoever that this would in fact occur.

In the second place, the use of "marginal cost pricing" for the purpose of depriving industrial users of gas, if successful, will necessarily force those users to turn to oil, thereby increasing the demand for foreign oil in direct contravention of other national policies.

In the third place, the use of "marginal cost pricing" for the purpose of forcing industrial users of gas to abandon gas service will cause an increase in rates to residential and other high priority users, in direct contravention of Congressional policy as expressed in Title II of NGPA. In setting bounds for incremental pricing under that section, Congress expressly recognized the rate reducing benefits of industrial service and was particularly sensitive that surcharges not cause that result.

It is conclusively proven that losses of industrial load result in a major upthrust in residential and commercial rates. This is for two clear reasons. All of the fixed costs of labor, plant maintenance, return and other items, now largely paid by industry, must be borne by residential and commercial users. And industrial rates are characteristically set close to value of service and above their proper share of the cost of service.

As above stated, UDC respectfully submits that the whole concept should be deleted from the report.

4.5 THE DRAFT'S PROPOSITION THAT "AVERAGE COST PRICING"
WILL RESULT IN IMPROPER SHIFTING OF GAS BETWEEN PIPELINE
SYSTEMS IN 1985; AND THAT "MARGINAL COST PRICING"
WILL PREVENT THIS RESULT.

On page 2, the Marginal Rate Draft adopts the thesis of the Technical Staff Analysis that in 1985 pipelines with large amounts of embedded price controlled supply can out bid those which have small amounts of price controlled supply; and that decontrolled gas will, therefore, be won by the former to the detriment of the latter class of pipeline.

Inferentially, it would seem this problem is laid at the door of "average cost pricing", though how this is done we fail to see. The real culprit is Federal price controls at the wellhead. But, in any event, it is boldly asserted on page 3 of the Draft that the situation will be cured by "marginal cost pricing".

Presumably, it is believed that the disparities among pipelines will be cured by reductions in demand which are claimed to result from marginal pricing. But how can this be assumed or concluded? There is nothing to show that the adjusted levels of demand will bear the same relationship to embedded supply on all pipelines. Indeed, the substitute differences between supply and demand could be even more pronounced, depending on how the claimed demand reductions varied from pipeline to pipeline.

In 1985, each pipeline will be bidding for new gas as its then needs for new long term reserves appear to be; and those needs are bound to differ, marginal pricing or no marginal pricing.

UDC respectfully submits that the contention that all this will be eliminated by the mere institution of marginal pricing is entirely unjustified and should be eliminated from the Report to Congress.

4.6 THE DRAFT'S PROPOSITION THAT "AVERAGE COST PRICING" COMBINED WITH PRICE CONTROLS PROVIDES LESS INCENTIVE FOR CONSERVATION THAN IS INDICATED BY MARGINAL WELLHEAD COSTS AND THAT, WITH "MARGINAL COST PRICING", "ALL CONSUMERS WOULD SEE STRONG AND APPROPRIATE INCENTIVES FOR CONSERVATION".

Criticism of the conservation resultant from existing utility rate forms is unjustified and improper in the extreme. All utility services are price elastic; and as "rolled-in" utility rates have increased in recent years, all classes of consumers have conserved and are continuing to conserve. The results have been remarkable and estimable.

If there has been too little conservation to satisfy ERA, the fault should be placed squarely at the door of Federal regulation of wellhead prices, not at the door of "average cost pricing".

Of course, if all gas service were priced marginally on the basis of new wellhead prices in accordance with classic economic theory, rates would be increased and conservation would likewise be increased.

But the deficiencies and limitations of this concept have been pointed out above. Under cost of service regulation at both the Federal and State levels, all gas service cannot be marginally priced on the basis of new wellhead prices.

If marginal prices are to be applied to all users, this can cover only a small part of the service; and, on the balance, rates at less than average cost must be used. How end users will conserve in the face of this new rate structure is anyone's guess. Many are only influenced by the total utility bill for service; and total costs are the same. It cannot be stated categorically, as in the Draft, that conservation incentives for all consumers would be greater under marginal cost pricing.

If marginal pricing is applied only to industrial users, then the rates to residential and commercial users are reduced; and, therefore, the vast majority of users would see less incentive to conserve. This is one of the many vices of "incremental pricing" under Title II of NGPA.

UDC submits that the ERA Report must fully and fairly explain the conservation achievements of existing utility rates and the difficulties which lie in the way of improving this situation through "marginal pricing".

4.7 THE DRAFT'S PROPOSITION THAT, UNDER "AVERAGE COST PRICING", AND WELLHEAD PRICES FOR DECONTROLLED GAS IN 1985 WILL BE FORCED "ABOVE THE LONG RUN MARKET CLEARING PRICE", BUT THAT "END USER RATES TIED DIRECTLY TO MARGINAL WELLHEAD COSTS" WOULD BRING WELLHEAD PRICES IN 1985 "DOWN TO THE LONG RUN MARKET CLEARING PRICE".

The foregoing concept is stated on pages 2 and 3 of the Draft, -- the proposition as to the evil effect of "average cost pricing" being based on the Technical Staff Analysis of DOE's Office of Policy and Evaluation.

In economic parlance, the market clearing price is that price which brings the supply of a freely traded commodity into balance with the demand for the commodity; -- so UDC assumes that, in using the term "long run market clearing price", the Marginal Pricing Draft is saying that end user rates tied to wellhead costs will cause wellhead prices for new gas in 1985 to be at that level which balances long run supplies of new decontrolled gas with long run demand for such gas; -- whereas rates based on "average cost pricing" will fail in this respect.

Considering the grave uncertainties which surround this untried rate form, UDC respectfully suggests that this far-reaching endorsement of marginal pricing cannot and should not be made in ERA's Report to Congress. So to do would be irresponsible and contrary to the public interest.

As has been pointed out above, marginal cost rates may not reduce the total demand for gas or alter the place or places at which the demands will arise.

On the supply side, ERA has no certain ability to predict what the situation will be in 1985, -- in the face of continuing price controls under NGPA, and steady inflation in costs. Supplies may be plentiful or terribly short in 1985; and it may take years of decontrolled drilling after 1985 to rectify the drastic harm occasioned by Federal pricing under the Natural Gas Act and NGPA. To say as does the Draft that marginal pricing will surely bring demands into balance with then supplies is the purest figment of the imagination.

Furthermore, end user rate forms will have very little influence on the buying decisions which will be made by pipelines for new wellhead supplies. The business of an interstate pipeline is to meet those requirements which will be placed upon it by all of its wholesale and retail customers under the long term service agreements which exist between them. Some pipelines may be in relatively good supply balance; others may have drastic needs for new gas. In any event, they will make purchase contracts according to long term necessities as they appraise them between now and 1985; and, to conclude, as does the draft, that existing utility pricing will lead to exaggerated and improper decisions, while marginal pricing will properly limit the decisions is pure fantasy.

V

IN THE SECTION ENTITLED RATE DESIGN,
THE CRITICAL PROBLEM OF CONFORMING RATE DESIGN
TO OVERALL COST OF SERVICE MUST BE TREATED
IN FAR BETTER FASHION; AND THE LIMITATIONS
WHICH THIS PROBLEM IMPOSES ON THE EFFICACY
AND EFFECTS OF MARGINAL RATES MUST BE EXPLORED.

The discussion of this all important problem on pages 11 and 12 is all too brief and cavalier. It fails to adequately explain the nature of the rate making process, the limitations which cost of service imposes on the use of marginal pricing, and the nature of the solutions which must be achieved.

As has been pointed out above, rates must be so designed that they will fairly provide the overall cost-of-service of the utility and this means that they cannot be too little, on the one hand, nor too great on the other. Meeting this design requirement is the most difficult problem faced by the utility, the users whom it serves and the local regulatory authority.

The rates must produce the required revenues as the service is rendered. Rates cannot be imposed retroactively to recover shortages in revenue or to adjust to the revenue requirement. Refunds are both expensive and unsatisfactory. Therefore, all rate making is designed to render one bill for the service just as soon as possible after the service is rendered. All this played a critical part in the design regulations by the Federal Energy Regulatory Commission for the implementation of the surcharges required by Title II of NGPA. And it would play a similar part in the design of any marginally priced rates.

Thus, if rates based on high wellhead and other marginal costs are to be utilized for all or any portion of utility service this must be in company with decreased rates for other service during the same billing period, with the two rates taken together equating to the cost of service or to "average cost pricing". There is no way around this necessity; and ERA's Report to Congress should fairly emphasize the same.

Furthermore, this portion of the Report should emphasize the severe limitations which these necessities impose on the benefits which ERA otherwise hopes to achieve with marginal pricing.

VI
THE ERA REPORT SHOULD EMPHASIZE
THE GRAVE RISKS TO PUBLIC SERVICE
WHICH LIE IN ANY INNOVATIVE RATE FORM.

The rates for utility service must be designed with reasonable assurance that they will meet the overall costs which are incurred in rendering the service, for only then can a distribution company provide assured public services on a sound basis in the consumer and public interest.

These necessary results can be fairly well predicted in connection with existing utility rate designs; but every new and tried rate form presents an enigma. No one knows how the users will react and what the overall requirements for service will be.

End user rates predicated on the marginal cost theories expressed in the Marginal Rate Draft might produce essential revenues as hoped but, on the other hand, they might not. And these uncertainties can vary in magnitude from utility to utility depending on the character of the market served and the nature of the supply arrangements.

For example, the switch from an existing rate structure to an innovative rate based on marginal cost could cause a major industrial user to abandon gas service, with disastrous consequences to the utility service and major resultant increases in residential and commercial rates.

Variations in weather could have an intolerable effect on revenues, depending on how accurately or inaccurately the new rates tracked the affect of changes in operations and storage.

Likewise, curtailments of industrial service required by an interstate pipeline shortage or other emergency could cause crippling losses in revenue, if too great a share of operating costs had been placed on industrial service.

These risks associated with marginal pricing are nowhere discussed in the Marginal Rate Draft. But they clearly should be exposed in the Report to Congress and UDC submits that a section covering this major problem should be included in the Report.

VII
THE DISCUSSION OF COST ASSIGNMENT MUST
HIGHLIGHT THE EXTREME DIFFICULTIES IN
REAL-LIFE UTILITY OPERATION AND THE POSSIBILITY
THAT USERS WILL NOT RESPOND AS PROJECTED.

At pages 5 - 9, the Marginal Cost Draft presents the subject of cost assignment in a highly theoretical fashion and assumes that users will indeed respond and take gas, or refrain from taking gas, in accordance with these analyses.

UDC is concerned, by way of example, with the discussion of seasonal costs and deliveries on page 7. There, it is said that utility plant shall be exactly balanced with user appraisal of the value of service--(which appraisal necessarily changes from day to day)--and that plant additions and operations shall be exactly tailored to these user appraisals. It is obvious that the model demonstrations and rate comparisons in the study will exactly balance utility plant, operations, customer use and revenues, in this fashion.

This theoretical presentation necessarily fails to disclose the potential pitfalls in the situation. Every distribution utility has, in being, an established utility plant with which it is rendering service to the user in the service area under an existing rate design. The entire cost of this service is being apportioned among the several classes of user in the light of years of experience with operations in the area.

The wholesale reassignment of these costs for the purpose of achieving desired ends through marginal rates is a very dangerous and questionable undertaking. It requires that costs be reassigned in accordance with an assumed idea of how users will react to an untried rate; and, if users do not so react--as they well may not--irreparable harm can be done to the public service, to all users served in the area and to the public interest.

No one knows until after years of experience how users will in fact respond to a given rate design. It is impossible to assume, as does the Draft, that cost assignments made for the purposes of a new and untried rate form will in fact provoke a desired user response.

These dangers inherent in any new and untried rate are discussed in UDC's First Supplemental Comments; and reference thereto is, respectfully, made. UDC submits that the section of ERA's Report on marginal rates--a potentially harmful rate--must fully disclose these cost assignment and user response problems to Congress.

VIII
THE DISCUSSION OF MARGINAL RATES
MUST EMPHASIZE PROBLEMS OF EQUITY
AND USER CLASSIFICATION WHICH WOULD BE
PRESENTED BY ANY MARGINAL RATE.

The First Supplemental Comments of UDC discuss the several considerations which lie at the base of sound utility rate design and, in particular, the absolute necessity for distributing overall revenue responsibilities fairly and equitably among homogeneous classes of users of the utility service. Years of experience have gone into the sound solution of these matters in each area of utility service.

Yet the Marginal Rate Draft does not discuss the necessity for testing any marginal rate against these standards.

It cannot possibly be argued that marginal rates should be imposed for the purpose of achieving desired Federal objectives willy-nilly and in defiance of these utility principles. Not only would this violate fundamental regulatory law; but it is more than probable that unfair and inequitable marginal rates in any area would defeat the very ends which the Federal government might hope to achieve.

Conservation of gas is a good example. This desired end is already occurring with remarkable rapidity in all classes of use under existing forms and classifications, to which users in each area of service have long been accustomed. It is very probable that much less conservation would result from any marginal rate which represented an unreasonable imposition of costs on any user classification or an unjust removal of costs from another, or which classifies users in ways which do not fit the residential, commercial and industrial characteristics of the area which is involved.

Rate design innovations must, in all cases, be adopted in an area of service only after careful consideration of the individual characteristics of that area and of the uses within that area, as is set forth in UDC's First Supplemental Comments. Whether marginal rates would or would not be just and reasonable and produce desired Federal objectives in an area will depend on the facts.

It is submitted that the report to Congress must fully set forth these considerations.

CONCLUSION

In conclusion, UDC would once again emphasize the grave importance of this Report to Congress and the absolute necessity, in the consumer and public interest, that a full and fair analysis and appraisal of this untried and untested rate form be presented. It is earnestly hoped that the Report will be modified and amplified in accordance with the foregoing suggestions.

Respectfully submitted,

United Distribution Companies

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AFFIDAVIT

Commonwealth of Massachusetts)
County of Barnstable) ss.

C. William Cooper being first duly sworn deposes and says that he is the Vice Chairman and General Counsel of United Distribution Companies, that he has had over thirty years of experience in distribution, pipeline and producer rate and operating matters, both as an official of and attorney for gas distribution companies, that he has prepared the foregoing comments, that the statements therein set forth are true and correct to his best information, knowledge and belief and that he is duly authorized to execute and file the same with the Economic Regulatory Administration on behalf of UDC.

C. William Cooper
C. William Cooper

Subscribed and sworn to before me this 20th day of
MARCH, 1980.

Paul E. Bartlett
Notary Public

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

792223A

Seventh Interim Report)
from ERA Regarding)
Marginal Cost Based)
Pricing and the Gas Rate)
Design Study)

ERA Docket No. ERA-R-79-22A

WRITTEN COMMENTS OF THE AMERICAN GAS ASSOCIATION

The American Gas Association (A.G.A.) is a national trade association of approximately 300 natural gas distribution and transmission companies, which provide natural gas to approximately 160 million consumers in all 50 states. A.G.A. member companies account for about 85% of all natural gas utility sales. A.G.A. welcomes this opportunity to comment on the Seventh Interim Report (hereinafter referred to as "Report") regarding marginal cost based pricing. Further, we believe that this Report is a critical aspect of the full gas utility rate design study and for this reason, we have undertaken a careful and close examination of the Seventh Interim Report.

The comments to follow begin with a general statement of concern regarding the basis of the Seventh Interim Report, i.e., the Department of Energy (DOE) Technical Staff Analysis which projects possible future market conditions under the Natural Gas Policy Act of 1978 (NGPA). We have also expressed concerns regarding the use of marginal cost pricing theory as a basis for gas utility rate design. Finally, we enumerate our specific concerns with respect to the techniques, assumptions and conclusions which ERA has relied upon in addressing the topic of marginal cost pricing in the Seventh Interim Report.

Introduction

A.G.A. fully supports the three purposes underlying Title III of PURPA, viz., conservation, efficient use of utility facilities and resources and equitable rates to consumers. Specifically, A.G.A. whole-heartedly embraces the concept of providing conservation incentives to consumers while, at the same time, noting that the pursuit of this purpose should not be to the exclusion of the others. Moreover, A.G.A. does not believe that an entirely novel, risk-laden rate design concept (namely, marginal cost pricing) should be cavalierly embraced as the ultimate conservation incentive, particularly when the practical impacts of this theory have not been accurately addressed.

Existing utility rate forms (i.e., cost-of-service pricing) have proven effective in encouraging conservation while maintaining a proper relationship between the cost of providing gas service to different categories of customers and the price of gas to those customers. Residential conservation realized under existing rate designs (in the range of 12-14% between 1973 and 1978) is achieved without the drastic economic dislocations that will necessarily occur under a marginal cost pricing theory. Therefore, A.G.A. supports conservation incentives, but we are reluctant to endorse, as does ERA, a wholly untried, untested marginal cost pricing concept that might well prove disruptive to all classes of gas consumers.

Summary of A.G.A. Comments and Recommendations

- o A.G.A. believes there are basic and substantial deficiencies in the Technical Staff Analysis (on which ERA relies) which projects gas market conditions that might develop under the NGPA. (See I, infra.)
- o The general assumption underlying successful utilization of the marginal cost pricing theory is that all competing energy forms are also subject to such treatment. At present, other energy forms are not marginally priced. (See II, infra.)

- o Marginal cost pricing is inherently biased against new, more expensive supplemental gas sources. This bias tends to frustrate our national policy to enhance the development of domestic energy resources. (See III, infra.)
- o Because of the essentially novel nature of marginal cost pricing, substantiation of its positive and negative aspects is essential prior to recommending its widespread application. It appears, however, that ERA has placed reliance on the marginal cost pricing theory without such necessary background study. (See IV, infra.)
- o The Report offers no real evidence that the price signal a consumer receives from marginal cost pricing is based upon the last unit's cost rather than on the aggregate bill which the consumer receives for the utility service rendered. (See V, infra.)
- o ERA has identified the practical problems of implementing a marginal cost pricing schedule; however, they have failed to adequately resolve such problems, particularly regarding price elasticities and the specific rate proposals for achieving a utility's revenue requirements. Indeed, these latter rate proposals would violate the "equitable rates to consumers" purpose of PURPA. (See VI, infra.)
- o Regarding the proposed specific rates to implement marginal cost pricing, the multiple season and volumetric rates are biased against industrial customers in that such rates abandon the concept of rates based on the cost of providing service and thereby risk fuel switching by such customers. Such fuel switching could be to fuel oil which is in direct contravention of our national strategic objective to reduce our dependence on foreign oil. (See VII, infra.)
- o Conforming rates under a marginal cost pricing theory to meet revenue requirements (i.e., to avoid an excess or a deficiency of revenues) creates a problem which ERA assumes, without explanation, can be easily solved. (See VIII, infra.)
- o Specifically, to the extent that marginal cost pricing generates "excess revenues", the method chosen to reduce such revenues is critical. If the method is to reduce initial block rates while keeping the later blocks at a high, or marginal cost, the result will be an inherently inequitable and undesirable bias against all types of large users in each class of service regardless of need. (See IX, infra.)
- o To the extent that marginal cost pricing causes a greater likelihood of under-recovery of revenues, it imposes a greater uncertainty and instability on a utility. (See X, infra.)

- o With respect to a novel rate design schedule such as marginal cost pricing, it cannot be over-emphasized that any implementation, or proposed implementation, must be considered on a gradual basis only. This will avoid the adverse impacts which accompany the drastic imposition of a new rate theory. (See XI, infra.)

I. The DOE Technical Staff Analysis is Substantively Deficient in Several Respects

In forecasting the future gas supply scenario, the staff analysis is pessimistic, to the point of being unrealistic, in projecting the contribution from supplemental gas supply projects. This is particularly the case in regard to the contributions of LNG and SNC, which are completely disregarded. With respect to new technologies and North American imports, the DOE forecasts are well below industrial projections.

In addition, all of the unsatisfied gas demand which the staff analysis projects occurs in the very low priority use sector of gas demand (viz., industrial boilers and powerplant use). However, to the extent that such uses are not now "existing" and/or not covered by one of the exemption regulations promulgated pursuant to the Powerplant and Industrial Fuel Use Act (FUA), they will very likely be prohibited from being hooked up because of the FUA constraints. Therefore, the amount of unsatisfied gas demand which EPA anticipates may, in reality, not be as great as projected.

In regard to the forecasted misallocation of supplies, the staff analysis contends that aggressive bidding, well above fuel oil parity, by interstate pipelines for deregulated gas will be the

primary factor causing such misallocation. This assertion is based upon the proposition that such interstate pipelines will have large amounts of "old" gas into which they can roll-in the high cost of new expensive gas. This rationale breaks down insofar as we are not experiencing such behavior in present contract negotiations and bidding for deregulated deep gas. If the staff analysis supposition were in fact correct, one would expect that current deregulated deep gas contracts would be much higher.

For these reasons, we believe that the validity of ERA's marginal cost pricing draft is questionable given the deficiencies in the technical staff analysis on which the Report is based.

II. All Competing Forms of Energy Must be Priced Under a Marginal Cost Theory if Such a Theory is to be Effective and Achieve its Purposes

Traditional economic theory maintains that a marginal cost pricing system will not work unless all competing forms of energy are priced pursuant to a comparable "marginal" theory. It is apparent in the instant case that not all of the competitive energy forms are priced on a marginal cost basis. This is particularly true with respect to electricity and domestic oil (notwithstanding imminent decontrol) which are not priced at the marginal cost. For this reason, imposition of a marginal cost theory on the gas industry can only lead to a distortion in gas rates and usage, as compared to these other fuels.

III. Marginal Cost Pricing Creates an Inherent Bias Against Supplemental Gas Supplies

In view of the fact that we have a clearly established national goal to develop our domestic energy resources, it is particularly imprudent and ill-advised to impose marginal cost pricing on gas utilities. Marginal cost theory will create an inherent bias against the development of supplemental gas supply projects (e.g. LNG and SHG) since most new gas supply projects have high capital costs and produce gas at initially higher prices. However, under a system of cost-of-service/rolled-in pricing, new gas supplies can be rolled-in with existing supplies without causing major economic dislocation to the users of that gas. In fact, these prices will become competitive over the life of the project. A marginal cost pricing system, however, would frustrate the development of these domestic gas supplies and increase our reliance on foreign oil.

IV. Any Reliance on Marginal Cost Pricing Must Be Based Upon Substantiated Findings and Not Merely Conjecture

Rolled-in pricing is the traditional utility approach and should not be abandoned until alternative pricing concepts have, by controlled experimentation, been proven to be superior. Marginal cost pricing on its face is essentially inequitable because it treats different size customers within the same class of service differently and does not track the costs of providing a particular customer with service.

Moreover, ERA offers no sound justification for its claims (1) that marginal cost pricing will foster conservation and avoid misallocation of natural gas supplies in the future; and, (2) that existing rolled-in pricing practices will hinder conservation efforts and create supply misallocation. In addition to relying on unproven benefits of marginal cost pricing, ERA assumes, without adequate reason or substantiation, that the practical difficulties in implementing marginal cost pricing can be easily overcome. (These practical difficulties are discussed infra at Sections VI through X.)

Existing gas utility rates are the product of much fine tuning and many adjustments at the local level in order to meet the utility customers' needs. In addition, such rates have met the test of regulatory commissions and have been found to be fair, just and non-discriminatory. To abandon these tried and true rate concepts for no better reason than the possibility of achieving unsubstantiated, conjectural benefits from marginal cost pricing is ill-advised and would result in disastrous consequences.

V. ERA Has Offered No Proof that Consumers Perceive a Price Signal Based on the Last Unit's Cost as Opposed to the Aggregate Utility Bill

The "price signal" can occur at numerous different points on the scale of usage depending on the individual customer's characteristics. Within a class of service, the twentieth, fiftieth, or even eight hundredth therm (or an infinite number of other points) may be the additional therm for a customer.

Moreover, there is further evidence to suggest that the aggregate size of the bill, rather than the cost of the last unit, is the "price signal" really understood by customers. If marginal cost pricing were applied to a distribution company's rate

design, a radical and sudden change from present rate structures would likely occur. The resultant rate form would probably be incomprehensible to most consumers because rates based on pure marginal costs would require a vast multiplicity of schedules. In this respect, the aggregate bill received by the consumer, rather than the last unit's cost, offers the simplest and most readily ascertainable "price signal" for such consumer. Practically, for the customer to receive a "price signal" from the last unit's cost, he would have to: read his own meter; know how close he is to the marginally priced unit; and, be able to predict the weather. Clearly then, it is highly improbable that any "price signal" arises for most customers from the last unit's cost.

VI. ERA Has Failed to Adequately Address the Practical Problem, Inherent in Marginal Cost Pricing Particularly with Respect to Price Elasticities and Specific Rate Designs

Price elasticities, even if they were precisely measurable at a given point in time, cannot be considered to be constant. They are subject to future fluctuation due to relative changes in competitive fuel prices or the physical restraints related to gas distribution characteristics and customer usage patterns. In addition, price elasticities are based upon various other exogenous factors such as customer income and perception of conservation incentives generally. The very fact that estimates of future costs, elasticities, and competitive fuel prices are needed to implement marginal pricing indicates that such a rate theory will prove administratively burdensome and unwieldy and cannot necessarily be relied upon to recover costs and return future revenue requirements.

Moreover, the specific rate proposals which ERA proffers to conform revenue requirements pose problems themselves. In particular, inverted rates do not track cost causation and, in this respect, shift to large volume users a disproportionate burden of fixed costs. For this reason, we believe that inverted rates violate the PURPA purpose of promoting equitable rates for gas consumers.

VII. The Multiple Season and Volumetric Rates Which the Report Identifies Are Inherently Biased Against Large Commercial and Industrial Users

The multiple season and volumetric rates identified by ERA as possible rate forms to reflect marginal costs recognize no difference between customers and patterns of consumption, i.e., they create rates that are the same for all customers. In this respect, these rates deny the equity inherent in traditional cost-of-service rate design. Moreover, such rates frustrate economies of scale by forcing large users to assume a disproportionate share of fixed or imbedded costs. The result is clearly inequitable and assuredly detrimental to all gas utilities' customers because such multiple season and volumetric rates would cause fuel switching among large interruptible and firm customers. This fuel switching increases the cost to high priority (residential) consumers in that they are ultimately forced to assume the fixed cost formally carried by the large users who have left the system. Therefore, a marginal cost pricing theory utilizing multiple season or volumetric rates would create an unacceptably high cost burden for the high priority and firm industrial users. In addition, this cost burden, if great enough, would ultimately cause even firm industrial users to switch to other fuels. Indeed, such a result contravenes two of the

three purposes of PURPA, viz., to provide equitable rates to gas consumers and to promote efficient utilization of utility facilities and resources.

Furthermore, to the extent that the large users on the system switch to fuel oil, such a rate design also serves to exacerbate our nation's dependence on foreign oil supplies. This result clearly operates to frustrate our efforts to reduce our dependence on these foreign oil supplies and impedes our progress in achieving energy independence.

VIII. Conforming Rates to Meet Revenue Requirements Under a Marginal Cost Pricing Theory Creates a Problem Which ERA Has Not Adequately Addressed

Perhaps the greatest problem with any form of marginal cost pricing for gas rates is the revenue requirements problem. As long as the revenue that a utility is permitted to earn is limited to, and based upon, a return on imbedded costs, there is going to be a discrepancy between the revenue produced from pure marginal costs and the revenues that are allowed.

The Report dismissed this key problem by stating on page 12 that, "It will be assumed that some mechanism to meet any such deficiency or excess can be designed but will not affect the marginal blocks of rates for either distributors or pipelines." (Emphasis added.) This assumption is wholly inappropriate. Any deviation from pure marginal costs to all consumers will cause price signal distortions. To achieve the alleged purposes and benefits from the marginal cost pricing concept, such distortion must be minimized. (See IX, infra.)

On page 9 of the Report, it is stated that inverted block rates or changes to the customer charges can be used to adjust pure marginal costs to provide the authorized revenue. No reason for this selection of adjustments is made and no analysis of the impact of these choices is given. In light of such rates being a drastic departure from the norm, it is unreasonable to suggest utilization of these rate designs without explanation or impact assessment.

IX. The Mechanism for Conforming Rates to Meet Revenue Requirements Under a Marginal Cost Pricing Concept Must be Equitable Across All Customer Classes

As discussed above, a very real possibility exists that the use of higher marginal cost rates for all users would produce revenues far in excess of the allowable levels. ERA has advanced a means (inverted rates) by which these "excess revenues" could be returned by reducing the rates for small and medium volume users in both residential and commercial classes. By so doing, however, ERA has embraced the proposition that such consumers would be least likely to increase their energy consumption because of lower rates. This wholly denies ERA's alleged purpose of providing a strong conservation incentive to all consumers and, in fact, creates a conservation disincentive for these particular consumers. This is a wholly unreasonable position especially in light of the fact that these segments hold a large conservation potential. To provide generally lower rates to these sectors would ignore this conservation potential. Therefore, ERA's endorsement of inverted rate design schedule would in fact directly frustrate all of PURPA's three purposes, viz., to promote both conservation and the efficient use of gas utility facilities and resources and to provide equitable rates to gas consumers.

Another major practical problem arises in that the calculations or determinations of price elasticities needed to implement this theory are on the frontiers of economic science. Reliable answers may be impossible to achieve. A second problem occurs if high marginal prices are set for price-elastic loads (generally considered to be commercial and industrial), and "excess revenues" are returned to price-inelastic loads (presumed to be residential). As the commercial and industrial customers reduce or terminate their gas usage because other forms of energy become more competitive, the distributor must necessarily obtain substantial rate increases from the remaining high priority residential users to meet the necessary revenue requirements. (See VII supra for an outline of fuel switching and other problems created by imposing a disproportionate share of revenue requirements on low priority large volume users.)

X. Marginal Cost Pricing Theory of Rate Design Would Likely Impose Greater Uncertainty and Instability on a Utility

Under present gas rate designs, as compared to marginal cost pricing, a utility is afforded greater certainty, predictability and revenue stability. This is true because the utility, even though subject to the vagaries of the weather, is not subject to the additional instability resulting from a rate design based on marginal cost pricing. In present rate designs a major portion of fixed costs are recovered in early blocks and are therefore not largely affected by weather fluctuations. The same is not so for marginal cost pricing. Under a marginal cost pricing theory, much

of a utility's revenues result from the high marginal costs of the tail block units. Therefore, any weather fluctuations causing less consumption in these blocks would substantially reduce the utility's revenue receipts.

XI. The Necessity of Implementing a New, Untried Rate Design Concept on a Gradual Basis Cannot be Over-emphasized

In view of all of the above-mentioned problems, it is important to note that, at most, a gradual transition in implementing marginal cost rate design is indicated. However, even under a gradual transition, it is unclear what implementation procedures are necessary to minimize disruption, and which classes of service should be marginally priced in order to accomplish the theory's purposes. Notwithstanding such gradualism, it appears that certain problems are unavoidable, and that even under minimal application of the theory these problems will arise.

Conclusion

In view of the foregoing discussion, A.G.A.'s general dissatisfaction with the Seventh Interim Report and the treatment of marginal cost pricing may be summarized as follows:

- o Existing rate design is founded on sound logic, is cost justified, and has served the industry and its customers well. It has not been subject to criticism on ground of discrimination. Marginal cost pricing, on the other hand, would impose inequitable and discriminatory methods to conform a utility's receipts to meet its revenue requirements.
- o Traditional average cost pricing has proven to be flexible as a workable pricing concept in gas rate design.

- o Marginal cost pricing requires estimates of price elasticities, relative energy costs, and timing of supplemental supplies. All of these factors are subject to serious questions of reliability. Therefore, to base present rates on such estimates is unwarranted and ill-advised.
- o Marginal cost pricing will require of each gas company major expenditures of time and money to quantify. The effort will likely result in a rate design which will almost surely be far less desirable and equitable than that currently in effect. We believe, therefore, that before DOE and ERA endorse marginal cost pricing, the Rate Design Study must fairly demonstrate that this rate theory is administratively feasible and cost-justified.
- o There appears to be no certainty with respect to how marginal costs shall be measured, and translated into workable rate schedules. This must be clarified before any analysis of the impacts and effectiveness of marginal cost pricing can be undertaken.

Finally, it should be noted that the regulated gas utility industry is not opposed to ERA's primary goal of encouraging conservation of our nation's energy resources. Indeed, our industry is itself actively engaged in this pursuit. However, the regulated gas utility industry is opposed to any allegedly conservation-oriented rate design concepts which are costly, drastic, disruptive, confusing, of unproven benefit and which forsake the simplicity and known effectiveness of existing rate design concepts. Theoretical constructs such as marginal cost pricing are all well and good on

paper, but to impose, or even suggest such theories, without adequate substantiation of the positive and negative impacts would cause serious adverse consequences for our nation and the regulated natural gas industry, a vital national industry.

Respectfully submitted,

THE AMERICAN GAS ASSOCIATION

By
George H. Lawrence, President

Donald J. Schellhardt, Assistant
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Dated: April 2, 1980

COMMENTS
ON
"PRELIMINARY DISCUSSION DRAFT
OF THE GAS RATE DESIGN STUDY"

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

415

792222A

Preliminary Gas Rate)
Design Study Initial)
Impressions)

ERA Docket No. ERA-R-79-22A

WRITTEN COMMENTS OF THE AMERICAN GAS ASSOCIATION

The American Gas Association (A.G.A.) is a national trade association comprised of more than 300 natural gas transmission and distribution companies which provide natural gas to approximately 160 million consumers in all 50 states. Indeed, A.G.A. member companies account for about 85% of all natural gas utility sales in our nation.

We wish to take this opportunity to set forth our initial impressions of the Preliminary Gas Rate Design Study (hereinafter referred to as "Study"). It should be noted that the summary discussion to follow presents only A.G.A.'s preliminary impressions which are proffered generally to aid the Economic Regulatory Administration (ERA) during its final deliberations and intra-departmental review. These are not intended to be, nor should they serve as, A.G.A.'s final written comments on the subject of the Study. We will be submitting, by the April 11 deadline, detailed written comments on this Study.

Summary of A.G.A.'s Initial Impressions of the Preliminary Gas Rate Design Study

- o At the outset of this discussion, it is important to note that existing, traditional gas rate designs are the product of years of fine tuning and adjustment to meet consumers' needs at the local level. These rates have been found by State regulatory commissions to be fair, just and non-discriminatory. Indeed, existing rates presently incorporate, to the extent possible given the social and political climate within the State, all three of PURPA's purposes, viz., conservation, efficient use of utility facilities and resources, and equitable rates to consumers.

- o A key to energy conservation is using the "least costly", most efficient fuel in all applications. A recent study conducted by the Carnegie-Mellon Energy Productivity Center concluded that if the U.S. had followed a "least cost energy strategy", it would be consuming less energy.* The only major increase in fuel use in that study was a 68% increase of gas use by industry. The Carnegie-Mellon study therefore tied gas use in industry to an overall national strategy for efficient use of all energy forms. Marginal cost pricing of gas to industry would discourage gas use in industry -- in favor of other, less efficient fuels.
- o Marginal cost pricing, as envisioned by ERA, would discriminate against gas energy in that most energy supply industries (e.g. electric and oil) do not marginally price their products. The natural gas industry is a regulated industry which imposes significant non-cost based penalties on industrial gas consumers. To impose an economic penalty on such industrial gas users -- and not impose it on fuel oil and electricity consumers -- would seriously undermine the market for natural gas.
- o The Study appears to be written to support a pre-determined conclusion, namely, that natural gas rates should be based on a marginal cost pricing theory. In this respect, the primary considerations appear to be that:

- gas customers of all classes must be aware of (and react to) per unit price signals reflecting the higher, marginal cost of supplies; and, that
- there must be an equitable transition to the deregulated market (post-1985) particularly regarding the relationship between interstate and intrastate pipelines in that market.

ERA's primary considerations begin to pale, however, when one recognizes that:

- ERA's recommended use of inverted rates, to conform revenue requirements, will preclude any effective conservation price signal from reaching small and medium volume users in both residential and commercial classes;
- consumers are more likely to receive a conservation price signal from the aggregate utility bill than from the cost of the last unit;

*The Least-Cost Energy Strategy: Minimizing Consumer Costs Through Competition, Roger W. Sant; The Energy Productivity Center of Mellon Institute; Arlington, VA; 1979.

- attempts to create a conservation price signal on the basis of the last unit's cost are confounded by "levelized" payment plans provided to consumers by gas utilities;
 - the rate design recommended to conform revenue requirements (i.e., inverted rates) does not track cost causation and, therefore, frustrates the "equitable rates to gas consumer" purpose of PURPA; and,
 - ERA has offered an unsubstantiated DOE analysis to prove that there will in fact be market distortions in the transition to a deregulated natural gas market.
- o A.C.A. believes that ERA must consider the long-range impacts of the Study to prevent its recommendations, particularly regarding marginal cost pricing, from working irreparable harm to the nation, the economy and to a vital national industry (i.e., the regulated natural gas industry). For example, such long-range considerations include the following:
- Marginal cost pricing creates an inherent bias against the development of supplemental gas supply projects. This bias is ill-advised if the U.S. is to reduce its reliance on foreign oil.
 - The increase in natural gas utility rates -- which are projected by ERA to result from marginal cost pricing -- may have an adverse inflationary impact on the economy.
 - Marginal cost pricing will create additional revenue instability and uncertainty for the natural gas utility industry because weather-related usage fluctuations will occur in marginally priced blocks.
- o A.G.A. continues to believe that ERA's reliance (for purposes of Chapter V, Marginal Cost Pricing) on DOE's Technical Staff Analysis (which projects possible future market conditions) is ill-advised because of the deficiencies inherent in that analysis. (For a discussion of these deficiencies, see Section I of A.G.A.'s WRITTEN COMMENTS on ERA's Seventh Interim Report, April 2, 1980.)
- o ERA risks unpredictable (and possibly disastrous) results by endorsing a novel, untried, untested marginal cost pricing rate concept. A.G.A. believes that no such endorsement is warranted without first determining: (1) whether ERA's assumptions surrounding marginal cost pricing and existing gas utility rate design are reasonable; and, (2) whether the costs of utilizing a marginal cost pricing theory in gas rate design are

offset by the benefits derived therefrom. It would be sheer folly to go forward with a recommendation endorsing marginal cost pricing before determining whether implementation of such a theory is, in the case of gas utilities, administratively feasible and cost-justified.

- o Finally, as well as not fully analyzing the impacts and ramifications of marginal cost pricing, we believe that ERA has addressed the existing natural gas utilities' rate design (cost-of-service pricing) in a superficial manner and in a negative light. In addition to the unsubstantiated allegations that existing rate design will not create conservation incentives and will create supply misallocations, ERA has failed to recognize that existing rate design has in fact fostered conservation and will continue to do so as wellhead prices for natural gas continue to rise. (See discussion, supra.)

Respectfully submitted,

THE AMERICAN GAS ASSOCIATION

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Dated: April 2, 1980

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

Gas Utility)
Rate Design Study)

Docket No. ERA R-79-22

THIRD SUPPLEMENTAL COMMENTS
OF
UNITED DISTRIBUTION COMPANIES

Pursuant to the March 21, 1980, memorandum of Dr. Stephen S. Skjei, United Distribution Companies (herein called "UDC") submit these written Comments on the March 1980 Preliminary Discussion Draft of Natural Gas Design Study, which will be referred to as the "Discussion Draft" or "Draft".

UDC, earnestly, recommends:

- (1) the correction of several factual errors which have crept into the Discussion Draft;
- (2) the addition of important explanations of gas utility obligations, operations and rates, all of which are essential to the design of rates for this public service; and
- (3) the qualification or outright removal of numerous categorical statements criticizing rolled-in or average cost pricing and endorsing marginal or economic cost rates as the best means of solving perceived problems.

The opportunity to file these comments is much appreciated.

UDC continues to recommend that the final conclusions of the Economic Regulatory Administration's (herein called "ERA") Report to Congress will be limited in the manner recommended in UDC's First Supplemental Comments.

Filed: April 11, 1980

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I
IDENTIFICATION AND INTERESTS OF
UNITED DISTRIBUTION COMPANIES

Statements with respect to these subjects are set forth in UDC's original Comments filed July 2, 1979 and in its First Supplemental Comments filed February 25, 1980. The same are incorporated herein by reference.

II
INTRODUCTION

As has been set forth on the foregoing cover page, UDC submits that the Discussion Draft must be revised in several major respects and these will be presented in some detail below.

Understandably in this most complex subject, several errors of fact occur in the Draft; and it is obvious that these should be corrected for the final Report to Congress.

But the deficiencies of the Draft are, in UDC's opinion, even more substantive.

To begin with, the Discussion Draft appears to be so anxious to rectify certain problems perceived to result from Federal field price regulation and rolled-in utility pricing, that it jumps to ultimate conclusions without ever considering, in a deliberate and ordered fashion, the fundamentals of the gas utility operation here involved. But it is only in the light of these fundamentals that rate designs can be considered and recommended. These Comments, therefore, like UDC's First Supplemental Comments, recommend the addition of important explanations of gas utility obligations, operations (including curtailments) and rate principles, all as set forth below.

Furthermore, there appear at numerous places in the Discussion Draft, wholly unfounded criticisms of existing rate designs and equally unfounded endorsements of marginal and economic cost rates. These Comments will show in some detail why neither the criticisms nor the endorsements are justified--certainly not in the cavalier and categorical fashions here used. At the very least, all must be carefully tempered or limited and, in many cases, they should be removed in their entirety.

In this regard, UDC calls particular attention to the fact that the Discussion Draft analyzes neither the long-standing reasons for and acceptance of existing rate designs nor the profound problems confronting the adoption and implementation of marginal or economic cost rates. It all reads as though existing designs are inherently wrong and desired results will easily and naturally flow from economic cost pricing. The Report to Congress must fairly and objectively correct these impressions.

There are, for example, sound economic, operating and consumer acceptance reasons in support of declining block rates; and this rate form, when used, has a long history of review by State Regulatory Commissions and by consumers of all classes. Contrary-wise, the problems of designing and implementing economic cost rates are manifold and well known, particularly in conjunction with inverted rates as here advocated; and the results which would be achieved are highly uncertain. These practical problems of implementation and efficacy have been highlighted in testimony in numerous State regulatory proceedings; and they cannot lightly be ignored in the Report to Congress.

The First Supplemental Comments of UDC, at page 11 and elsewhere, stress how little of the ultimate cost of gas to the end user lies within the control of the distribution utility and how great is the necessity for synchronizing utility rate design with the fixed and pipeline purchase costs which the utility must bear, month by month, as bills are presented. These grave problems are nowhere addressed in the discussion of economic cost rates; and all revenue and revenue stability problems are brushed aside on the basis of the results of the hypothetical model. These deficiencies of the Discussion Draft must be cured, in the consumer and public interest, as we will show.

It is essential that the Report emphasize that all here presented by way of analysis is based on a hypothetical model in which all desired ends are inherent in the underlying assumptions. For example, the model exactly balances revenues with costs; and yet the real life results under new and untried rates may be far different and indeed disastrous. So too with conservation. Assumed goals are achieved because they are worked into the model; yet actual results will be far different.

By reference, UDC again submits the views, set forth in the First Supplemental Comments, as to the limited and cautious final conclusions which may be included in the Report to Congress.

As in prior submittals, UDC desires to express its deep appreciation of the opportunity to comment on this extremely important subject.

III
COMMENTS ON "CHAPTER II -
CURRENT PATTERNS OF DEMAND, SUPPLY AND
REGULATION IN THE NATURAL GAS INDUSTRY"

3.1 THIS INTRODUCTORY CHAPTER SHOULD
INCLUDE AN EXPLANATION OF GAS
UTILITY OBLIGATIONS, OPERATIONS AND
UNDERLYING RATE PRINCIPLES.

While Congress has mandated a study of "gas utility rate design", the Discussion Draft, at no point, explains the fundamentals of utility service and operation and the underlying principles of rate making which are essential thereto. Yet full understanding of these matters is essential to consideration and determination of every issue involved in the design of rates.

Indeed, the Discussion Draft is so concerned with the solution of several problems which ERA perceives will result from Federal regulation and deregulation of field prices, that the fundamental driving forces of utility operation are brushed to one side.

This cannot be done in the consumer and public interest. The necessities and legal requirements involved in providing gas service to the public must be taken into full account in the consideration of existing rates and of any new and untried rate designs.

UDC submits that this introductory chapter of the ERA Report to Congress should commence with a sound explanation of gas utility service as such and of the underlying rate principles which are involved in that service.

To begin with, it would seem that the Report should summarize the numbers of consumers served throughout the Nation, the large number of distribution utilities engaged in the public service and the very great variations in the size of utility operation and character of areas served. These variations are stressed in the First Supplemental Comments filed by UDC in this matter.

The Report should, we submit, explain that every such utility is obligated by law to render service to all consumers within its service area on a continuing basis; and that, to this end, it has installed distribution facilities, arranged long term gas supplies and necessarily arranged its operations in such fashion as will cope with variations in demand, as well as operating emergencies and interruptions in supply, In particular,

it must be stressed that, for reasons of health and public safety, gas service to the millions of residential, small commercial and small industrial users along the distribution systems, must be continuous and uninterrupted, and that every prudent and necessary step to this end must be taken, including, where necessary, the curtailment and interruption of large users.

Underlying principles of constitutional and regulatory law require that the rates charged to the persons using the utility service shall be just, reasonable, non-discriminatory and non-preferential to all users. Such rates shall be limited to such amounts as will compensate the utility for the costs prudently incurred in providing the service and enable it to attract the capital necessary to the rendition of the public service on a sound long-term basis.

In all cases, the design of rates for gas service necessarily deals with the existing and ongoing utility operation in each area of service and its primary function is to apportion the overall costs of the service in an equitable fashion among the several users. As set forth in the First Supplemental Comments of UDC, at page 10, the design of these rates in the case of each utility necessarily involves balanced and careful judgments based on the cost of serving the several classes of user, the value of the service to those users, historical relationships among classes, the need for conservation and the necessity for coping with variations in weather and market demand. All designs must function satisfactorily under local regulatory procedures.

Furthermore, as stressed in those Comments, sound rate design must take into account the absolute necessity that the utility meet its tremendous fixed costs involved in the operation and its equally tremendous costs for purchased gas supplies. Labor, maintenance, capital and other costs must be met as they occur. The tremendous bills rendered each month by pipeline and other gas suppliers must be paid. Existing rates are designed to accommodate these needs; and any new rates must be weighed on this same scale.

It is also essential that the Report analyze the subject of curtailments in a clear fashion, particularly in view of the questionable suggestions later in the Draft, that shortages may be managed by proper pricing. UDC has stressed, in prior submissions to ERA, the absolute necessity that demand be limited to available supply. This must be done for reasons of health and safety; and, when shortages occur, the utility must curtail large industrial users to such extent as is necessary to achieve this balance. This is a physical necessity which must be met regardless of rates; and no rate design, however meritorious its intent, can take its place.

UDC submits that these fundamental requirements and principles must be laid forth at the start of the Report and that all aspects of the rate design study must move forward in their light.

3.2 COMMERCIAL USES OF GAS (Chapter II, page 7).

In contrast to what is said, there is great potential for conservation in the area of commercial space heating. (See "The Least-Cost Energy Strategy" by Roger W. Sant, pages 30-34.)

Much conservation has already occurred as existing rolled-in rates have increased; and much more will occur as these rates continue to rise.

3.3 "WHO SUPPLIES GAS" (Chapter II, page 10).

Several errors of fact have crept into the first paragraph:

- (a) Many distributors secure supplies from intrastate pipelines.
- (b) Federal regulation does not prohibit intrastate marketing from a gas field only dedicated in part to interstate commerce.
- (c) Some distributors own extensive transmission systems and secure pipeline supplies at points far from the "city gate".

While interstate pipeline supplies have predominated during recent decades, the ERA Report should stress the general obligation of the distributor to provide supplies for its service area and the great "self-help" steps taken by distributors in the 1970's as a means of supplementing pipeline gas and offsetting pipeline curtailments.

In this regard, the important role being played by local production, SNG, LNG, storage and other means should be discussed, as emphasized in the First Supplemental Comments of UDC.

3.4 "ROLE OF LONG-TERM CONTRACTS" (Chapter II, pages 14 et seq.).

Several errors of fact which appear in this discussion should be corrected:

- (a) Service agreements between pipelines and distributors do not limit or determine field prices paid to producers. This was the case in certain early contracts in the 1930's and 1940's, but it is not now the case.

- (b) Available gas migrated to the intrastate market in the 1970's not for the reason stated but simply because there was a demand for the gas in the intrastate market and producers could sell to that market free of the rate limitations imposed by the Natural Gas Act.

This portion of the Discussion Draft should be modified to emphasize that wholesale service agreements between pipeline and distributor have been held by the United States Supreme Court to be the appropriate form of business arrangement contemplated by the Natural Gas Act for use by the industry. (United Gas Pipeline Co. v Mobile Gas Service Co.; 1956, 350 U.S. 332; In Re Permian Basin Area Rate Cases; 1963, 390 U.S. 747)

3.5 "FEDERAL REGULATORY POLICY" (Chapter II, page 15).

Interstate pipelines are not "monopolies" and are not protected as such by the certificate provisions of the Natural Gas Act. (Section 7(g) of the Natural Gas Act; 15 U.S.C.A. See 717f(g))

3.6 "NATURAL GAS POLICY ACT" (Chapter II, pages 16-18).

On page 18, the second full paragraph draws the conclusion that pipelines holding "old gas" will have "a significant competitive advantage" as long as they are permitted to use rolled-in rates. It is submitted that there is no ground for this conclusion and that it represents a very grave oversimplification of a very complex problem.

In the first place, intrastate and interstate pipelines do not compete with one another in sales of natural gas. They operate in different geographical areas and against different market forces. Given its marketing area, the interstate pipeline, even with old gas, may be in a poorer competitive position than is an intrastate pipeline operating in the same gas producing area.

In the second place, the gas purchase operations of each pipeline and the prices which each will pay, at any point in time, are determined by its long term gas reserve and deliverability situation and numerous other factors. These will vary from time to time and from one producing area to another.

It cannot be cavalierly said, as here proposed, that a competitive advantage will invariably stem from the existence of rolled-in rates; and it is, therefore, suggested that the last two sentences of the second paragraph on page 18 be omitted.

3.7 "FACTORS AFFECTING PRICE
AT THE CITY GATE"
(Chapter II, pages 18-19).

An error of fact appears in the text on page 18. It is said that "frequently, the volume provision" in a contract between a pipeline and its distribution customer "is a percent of the remaining reserves available to the pipeline company". This was true in early wholesale contracts executed in the 1930's, but it is no longer the case. Existing contracts commit the pipeline to deliver specific volumes for a term of years without reference to reserves.

3.8 "PURCHASE PRICE"
(Chapter II, pages 19-20).

The first full paragraph on page 20 casts "rolled-in" pricing by pipelines in the role of the villain of the 1970's. It is said that it provided the pipelines little incentive to minimize costs of their supplies; and that "during the 1970's, when gas prices began to rise rapidly, there was substantial demand in excess of the supply available to the interstate market". The only inference which can be taken from this paragraph is that excess demands resulted from "rolled-in" pricing and that the pipelines recklessly paid high prices to satisfy the demand.

This is a grave misinterpretation of what actually happened in those years.

The industry used "rolled-in" pricing, to be sure,--as did the competing oil distributors, coal and electric utilities. But the excess of demand over supply resulted plainly and simply from the decline in drilling by producers during the 1960's, as a result of field price limitations imposed by the Federal government, and the sale of all available gas at unregulated prices to the intrastate market during the 1970's. Of course, interstate pipelines paid increasing prices (to the extent they were permitted so to do under Federal regulation) in a desperate effort to end curtailments in theretofore existing levels of service.

Furthermore, new Federal environmental policies, not rolled-in pricing, was the major cause of such new gas demand as did occur in the 1970's.

UDC submits that the whole paragraph should be deleted.

Likewise, the second full paragraph on page 20 is erroneous, for it applies, if at all, not to contracts between pipelines and distributors, but rather to contracts at the well between pipelines and producers. Under FERC regulations, service by pipelines to distributors is rendered at tariff rates which are raised or lowered according to established regulatory procedures. It is only in producer contracts that contract prices could continue in effect for periods after Federal regulation is removed.

3.9 "SHORTAGE"

(Chapter II, pages 25-26).

In the first full paragraph on page 26, it is said that the shortages of the 1970's and consequent curtailments led to

"disruption in the consumption pattern that has [been] undoubtedly led to an inefficient pattern of end use consumption".

This, it seems, is an unfair characterization of what was undoubtedly the most severe situation which ever occurred in gas distribution.

When pipeline curtailments of service were brought on by their inability to secure necessary supplies in the gas fields, the distributors were in turn forced to curtail their own deliveries,--at least until they could develop substitute self-help. As has been said above, it was absolutely essential to bring the demands served by each individual pipeline or distributor down to the level of its available supplies. Large industrial users were in all cases first curtailed and, as pipeline curtailments increased, distributor curtailments were necessarily extended to other users. Then, as distributor self-help projects came on line, or as pipeline service was restored, service to curtailed end users was progressively restored.

It is true that levels of curtailment differed from pipeline to pipeline, according to their several supply situations. And it is true that levels of curtailment differed from distributor to distributor, according to the curtailments suffered in pipeline deliveries and the extent of available self-help supplies. Consequently, some distributors were able to supply low priority users, at a time when others were curtailing higher priority users. But these differences resulted naturally from the fact that each pipeline and each distributor is necessarily predicated on its own contracted for or owned supply and must meet the uses within its own service area to the best of its ability.

It is recommended that the foregoing quoted sentence be deleted; and that the ERA Report be limited, accordingly.

3.10 "RATE PATTERNS"

(Chapter II, pages 26-27).

In the first paragraph under this heading, the rate differential between residential and industrial users is attributed to the fact that utility rates are "dominated by the concept of cost responsibility" and by the assignment of costs "to use during peak periods" and to the number of customers.

This implies that some fault is inherent in the rate methodology and differential; but, why so?

In every utility operation and, indeed, every kind of business, the small retail sale, on a per unit basis, is more costly to render than the large. Very large separable and identifiable costs are involved in the service of every residential user of natural gas,--though in practice it is customary to cause industrial users to bear a share of these costs.

Furthermore, the concept of cost responsibility is common to all utilities and is, indeed, carried forward in the "economic cost rates" advocated by later portions of the Discussion Draft. Customers who take gas at poor load factors and impose peaking facility requirements normally pay higher rates than customers who take service at high load factors. And costs are not assigned to residential users merely by reason of "the number of customers";--rather, certain basic costs are incurred in serving all residential users as a group and, to the extent that they are allocated to this class of user, they are reflected in rates for the group and borne according to the quantities taken.

It is suggested that differentials between small residential and larger industrial usages be accepted as normal to any utility operation.

IV
COMMENTS ON "CHAPTER III -
MAJOR STUDY ISSUES"

4.1 THE INTRODUCTORY STATEMENT
ON PAGES 1-5.

In the last paragraph on page 4, it is said that "incremental pricing" under Title II of the Natural Gas Policy Act of 1978 (herein called "NGPA") (15 USC §§3341 et seq.) is designed to encourage gas users to switch to coal or fuel oil. Quite the reverse is true. Congress specifically empowers FERC to guard against fuel switching, through reductions in the alternate fuel price in Section 204 of NGPA and exemptions granted pursuant to Section 206(d). The Report of the Conference Committee, at page 102, emphasizes the broad authority of the Commission in this regard.

4.2 "ISSUES"
(Chapter III, pages 5-9).

4.2.1 The Introductory Statement
on pages 5-6.

UDC strongly objects to the introductory statement of Issues, for the reason that it does not state the issues which are to be considered and merely recites unfounded conclusions as to the impropriety of existing rate designs.

The first sentence of the introduction states that "NGPA attempts to rectify through wellhead decontrol the undesirable consequences of years...of rolled-in or average cost pricing by pipelines". That is a complete non-sequitur. The Act was designed, as stated, to rectify the consequences of years of unsound wellhead price regulation. But there is nothing in the NGPA showing any design to "rectify" rolled-in or average cost pricing; and there is absolutely no connection between wellhead decontrol and rolled-in pricing by pipelines.

Furthermore, there is no basis for the charge that "rolled-in or average cost pricing by pipelines" has led to

"supply shortages";

"inadequate levels of conservation"; and

"use of gas as a boiler fuel in some locations... at the same time that gas was unavailable for new home heating purposes in other locations".

The supply shortages should be placed solely at the door of the cause thereof: Federal price controls at the wellhead which reduced drilling by producers and drove gas to the intrastate market.

Conservation has been increasing rapidly among all classes of gas user as rolled-in gas prices have risen during the 1970's. Among UDC Members, for example, residential and industrial conservation experienced during the past seven years represented 13.8% and 15.4%, respectively, to total demand. Under existing rate designs, conservation is already so great that distribution utilities now have excess supplies of gas. There is no basis for saying that accomplishments to date are "inadequate".

Differences in the relative uses of gas during curtailment were in every case due to the varying supply situations of the several pipelines and to the varying self-help measures of the distributors. Some pipelines had more plentiful supplies, irrespective of pricing techniques, and their curtailments were lower. Some distributors took self-help measures which enabled them to meet all requirements, including boiler fuel use, despite pipeline curtailments. There is no basis for claiming that the differences may be laid at the door of "rolled-in" or "average cost" pricing by pipelines.

It is, respectfully, submitted that the criticisms of Federal regulation in this introductory text should be confined to wellhead pricing policies.

4.2.2 "Price Quantity Stability
in Gas Markets"
(Chapter III, pages 6-7).

It is here argued that interstate pipelines, which have large supplies of "old gas" and use rolled-in prices, will be able to outbid intrastate pipelines for new supplies of decontrolled gas, thereby having a competitive advantage. And, having arrived at this conclusion it is said that rates which "reflect the costs of acquiring the last unit of gas sold" would reduce demands on the interstate pipeline and decrease the imbalance between the interstate and intrastate markets.

Neither of these conclusions is supported; and each is highly questionable.

Mention has already been made of the fact that interstate pipeline purchases and pricing actions will be determined by many factors other than rate design. The status of reserves, the deliverability of wells, the location of pipeline facilities and numerous other factors determine the necessity for purchasing additional gas; and these will differ markedly between pipelines and over time. Furthermore, many pipelines are still trying to rectify the serious depreciation of reserves and deliverability occasioned by their inability to purchase new supplies during the 1970's.

Pipeline gas purchase programs at any point in time are not directly keyed to current changes in the requirements of distribution utilities. They are concerned with long term supply-demand relationships and how these will, in fact, appear as the 1980's progress is anybody's guess. Some pipelines may be in dire need of new gas reserves in 1985 regardless of demand conservation. Others may not. The then overall energy situation will have an important bearing on the subject; as will then governmental policy with regard to the relative desirability of fuel uses. Witness, for example, the dramatic changes which have taken place in all areas of this subject during the past three years.

Marginal rates could change the situation only if they would materially reduce demands on each interstate pipeline which competes with an intrastate pipeline for a given new supply. This is not at all certain. Conservation is rapidly increasing as rolled-in prices increase; and overall conservation may be as great with rolled-in pricing as with new and untried marginal rates. Because of the restriction of rates to the revenue requirement, any high marginal rate to one use is necessarily offset by a low rate to another; and the net effect could be less conservation with marginal rates than will naturally occur with rolled-in rates.

The Report to Congress cannot categorically state, as does the Discussion Draft, that marginal pricing materially affects any perceived imbalance between interstate and intrastate pipelines.

4.2.3 "Shortages Prior to 1985" (Chapter III, pages 7-8).

All during the 1970's, levels of curtailment necessarily differed from pipeline to pipeline and from distributor to distributor, for the supply-demand balances differed. But it is implicit in the argument here made that changes in rate design can somehow place all companies across the Nation in uniform supply-demand relationships and that this can be done for the 1980-1984 period.

This necessarily assumes that a new and untried rate design will have monumental effects on demands on an almost instantaneous basis and that these changes in demands will be such as to bring all utility services into uniform relationship with supply.

This is a Herculean jump! Changes in rate design and consumer response thereto take years to accomplish.

It normally takes a year or more to get a new rate form into effect and after that conservation only comes as users grow accustomed to the new situation and install new gas equipment or turn to alternate fuels' equipment. It is more than probable that no material effect whatever would be felt from new and untried rates during the three years which will remain after ERA's Report is completed; and to assume that these could level out market uses over the Nation as a whole stretches the imagination to the breaking point.

4.2.4 "Efficiency and Conservation" (Chapter III, pages 8-9).

Two key statements in this section are highly questionable.

It is said at the top of the page that:

"for gas to be used efficiently, its price must reflect its value to the nation as a substitute for oil." and

"Gas rate design must promote levels of conservation of gas which are in accord with the value of gas in reducing oil imports."

Many end users, however, are not motivated to conserve by any comparison with the price of oil. For example, a residential user using gas heat installs conservation equipment solely in the light of gas prices versus cost of conservation equipment. So too, with a commercial building using gas for process and heating purposes. So too, with a gas process user who cannot use oil as an alternate.

UDC, earnestly, supports efficiency and conservation and this is growing steadily among all gas users as rates steadily increase under existing rate designs. It is the rate increase as such which increases efficiency in gas use and conservation and the price of an alternate fuel as such does not motivate actions to this end. If he could use oil as an alternate, he might turn to oil and reduce his gas demand; but this is directly opposed to the ends here sought by ERA.

Indeed, insofar as the achievement of efficiency and conservation is concerned, there is no logical reason for equating gas prices with the price of oil as such. And for many users of gas, this concept could represent a price penalty not conducive to public good. For example, if it makes no economic or conservation sense for a given type of user to install more conservation equipment, there is no point in still further increases in his gas rate just to equate the same to the price of oil.

4.3 "IMPLICATIONS FOR THE STUDY" (Chapter III, pages 9-12).

UDC strongly opposes the first paragraph of this section, at the bottom of page 9 and running over onto page 10. The categorical criticisms of existing rate structures and equally categorical approbation of economic cost rates are neither supported nor sound.

Most of the individual factors mentioned in these conclusions have been discussed above, but essentially it all comes down to the proposition that existing market uses are unsound and that "economic cost rates" will work a marvelous transformation in a very short period of time.

UDC earnestly disputes this flat and unqualified proposition, for reasons discussed in some detail above.

Conservation is now occurring under existing rates and there is nothing to show that it will be materially increased under economic cost rates, considering the fact that increases to one user necessarily decreases the rate to another.

Supply/demand balances differ and will continue to differ. That is of the very nature of the gas industry; and there is nothing to show that economic cost rates will transform the situation Nationwide.

V
COMMENTS ON "CHAPTER V -
MARGINAL COST BASED RATES"

5.1 "MARGINAL COST BASED RATES"
(Chapter V, pages 1-9).

5.1.1 "Economic Cost Rates"
(Chapter V, pages 4-7).

The knotty problem of balancing "economic cost rates" against the overall revenue requirement is discussed in the last paragraph on page 4 running over onto 5, and also in the first paragraph on page 7. UDC desires to make two comments with regard to this problem:

- (a) If a flat rate is used in order to balance out, there is essentially no change from "rolled-in" or "average cost" pricing.
- (b) If, on the other hand, an inverted rate is used, revenue instability is greatly increased; and the consequent costs and problems to utility service may be more onerous than the new rate form is worth. This will be commented on under the "Revenue Stability" point below.

"Economic cost rates" at the pipeline level are discussed in the last two paragraphs on page 5, and inverted block rates are suggested as a solution to the revenue requirement limitation. But the Discussion Draft fails to mention the serious problem resultant from differences in size of utilities who are customers of pipelines. Such customers vary in size from extremely large to extremely small and any inverted block rate will result in overall rate reductions to most utilities and major increases to the remainder. Any such result would lessen conservation and increase demands over wide areas of the Nation while unduly penalizing others; the kind of unequal treatment which the Draft elsewhere says should not occur.

5.2 "CUSTOMER IMPACTS OF
ECONOMIC COST RATES"
(Chapter V, pages 10-18).

This section of the Discussion Draft presents the conservation and other results portrayed by the operation of the hypothetical model, using all of the market, conservation and other assumptions adopted for the purpose.

But there is no certainty that these new and untried rate forms would achieve results of this same order in real life. Gas users may react to "economic cost rates" and, particularly inverted rates, in ways which are quite different from those which are portrayed in the model.

So too, the model assumes exact matching of revenues and costs, instantaneous changes in rates and other essentials which are proper for modelling but foreign to real life; and these could work far different results than those here shown.

UDC has no problem with the hypothetical discussion if clearly shown to be such. It is submitted that the heading to the section and the several conclusions should so state.

To this end the heading might read:

"CUSTOMER IMPACTS OF ECONOMIC COST RATES
AS SHOWN BY THE HYPOTHETICAL EXAMPLES .
DEVELOPED FOR PURPOSES OF THE STUDY".

5.3 "DISTRIBUTOR IMPACTS OF
ECONOMIC COST RATES"
(Chapter V, pages 19-24).

5.3.1 General.

As with the prior section, UDC submits that this section should clearly indicate that the impacts here discussed are those resultant from a hypothetical study and that actualities may be far different. To this end it is suggested that the heading be revised to read:

"DISTRIBUTOR IMPACTS OF ECONOMIC COST RATES
AS SHOWN BY THE HYPOTHETICAL EXAMPLES
DEVELOPED FOR PURPOSES OF THE STUDY".

5.3.2 "Revenue Collection"
(Chapter V, pages 19-20).

The model developed for the study is designed to provide rates which exactly achieve revenue requirements. Yet, in real life, this is one of the most difficult results to achieve with any rate design; and the problem becomes exceedingly difficult with any new and untried rate. No one can predict with certainty what will result and the ERA Report should clearly so state.

5.3.3 "Gas Purchases and Average
Gas Costs"
(Chapter V, pages 21-22).

This section of the Discussion Draft states categorically exactly what effects the assumed rate structures will have on pipeline purchases, the prices which pipelines will pay and the relative buying capabilities of inter- and intrastate pipelines.

All this, of course, assumes that pipelines will contract for new supplies in these years in exact relation to the conservation achieved by end users under the new rate forms.

But the fact may be far different. UDC has emphasized in the First and Second Supplemental Comments and above that pipeline purchases are motivated, determined and timed by many different factors; probably the least important of which is the exact level of end user demand at any given point in time. Yet the Discussion Draft makes no attempt to explain these many qualifications.

The EPA Report, UDC submits, must clearly state (1) that the results assume that pipelines will purchase new supplies in exact relation to trends in customer demand and (2) that pipeline purchases may, in fact, be far different.

5.3.4 "Load Factors"

(Chapter V, pages 22-23).

The Discussion Draft casually states that load factors will be worsened by economic cost rates and no attempt whatever is made to assess or illuminate the consequences.

Worsening load factor presents cost, safety and service problems of great magnitude; and given unusual weather problems or pipeline emergencies, irreparable harm can result.

Furthermore, the affects of worsening load factor at the distribution level are of extreme importance to pipeline costs and operations, as well as in the arrangement of field supplies.

This is not a problem to be lightly passed over; and the Report should clearly outline the difficulties which would be presented.

5.3.5 "Revenue Stability"

(Chapter V, page 23):

The Discussion Draft treats this extremely important subject with greater assurance than is warranted; and its positive conclusions must be tempered.

The hypothetical model is, of course, designed to balance out all utility costs and revenue needs. Yet with new and untried rate forms,--particularly of the kind here envisioned--, the event may be far different. Net income, far from being stable, may be more variable than ever.

Consumers served by a utility have no obligation to take specific volumes of service; and uses vary with changes in weather, economic conditions and other factors. Volumes and accompanying revenues may be reduced or increased far beyond the levels contemplated when rates are set. Consider, for example, how this affects revenue stability under the declining block rate currently in use in many areas and the inverted block rate here analyzed. Under a declining block rate, most fixed costs are covered in the initial blocks which customers use in either warm or cold weather, good or bad economic conditions, leading to stability in recovery of these basic costs. Under an inverted rate, fixed costs are in large measure cast into the higher blocks where there is great variation in take and hence variation in recovery of basic costs.

The ERA Report must emphasize that the model is designed to balance revenue requirements and that marginal cost pricing, if attempted, could lead to a serious depreciation of stability. Any such rates should be approached cautiously, with full awareness of this possibility.

5.3.6 "Volumes" (Chapter V, pages 23-24).

The positive statements in the Draft as to the extent of conservation and fuel switching necessarily assume the validity of all assumptions. Yet consumer reactions to marginal rates, and particularly to economic cost rates in inverted form, could be far, far different. The strong consumer desire for budget billing militates against any different affect from marginal rates than from existing rate designs.

5.4 "MARGINAL COST BASED RATES UNDER SHORTAGES" (Chapter V, pages 25-28).

This section of the Discussion Draft states, with assurance, that

"under a system of economic cost pricing, distribution companies would ration available supplies through prices".

The concept that marginal rates may be counted on to balance supply and demand at all times is far fetched. The theory may work well in a free market economy; but one is not dealing with that situation in the gas industry.

For example, the text on page 25 states that rates will be varied as availability of supplies varies, and that customer reactions will exactly track these rate changes.

All this overlooks the procedures, and accompanying lag, necessarily posed by State and Federal regulation--as well as the inevitable delay in consumer response.

In the first place, changing rates at the distribution level is a cumbersome and time-consuming task. There is invariably a long delay, in some cases years in duration. The supply/demand situation could change from surplus to shortage and back to surplus in the time that it takes to get a new rate in place. Witness the changes in supply/demand balance which have occurred in the gas industry in 1977, 1978 and 1979; and consider whether these could have been tracked through rate proceedings which involve months and months for hearings and decision.

In the second place, customer reactions to rate changes are not instantaneous. Conversion by an industrial user or installation of conservation equipment may take months or years. By the time an expensive new gas saving device has been installed, there may be another gas bubble in being.

It is, respectfully, suggested that the above quoted sentence should be deleted from the Report; and that both the heading and the text should emphasize the hypothetical character of the presentation and the practical problems standing in the way of achievement.

5.5 "NATIONAL IMPACTS" (Chapter V, page 31).

The Draft categorically states that "economic cost rates":

- (a) "induce a relative stability in the demand for gas during the period that wellhead prices are decontrolled";
- (b) "would not allow" interstate pipelines "to outbid" intrastate pipelines;
- (c) "reduce the incentives" for pipelines "to pay high prices" for decontrolled gas;
- (d) "could reallocate available supplies to customers who place the highest value on gas"; and
- (e) "could encourage conservation so that available gas can serve more customers".

While these results may be portrayed by the hypothetical model, none can be confidently predicted for real life, for reasons which have been set forth above and which are here summarized:

(a) "Relative stability in demand" during the next few years.

This assertion in favor of "economic cost rates" is far-fetched. It assumes that these new and untried rates will greatly increase conservation by users during the next three or four years; and, as has been pointed out above, this is most improbable.

The long periods required for the adoption and implementation of new rates and the fact that conservation comes only slowly and deliberately, militate against this result,--even if one assumes that the marginal cost rates will result in greater conservation than present forms of rates.

And it is far from certain that the rates would produce more conservation. The revenue requirement restriction means that every high marginal cost rate must be balanced by a lower than normal rate for other use, with the result that, overall, conservation may not increase.

(b) and (c) "Outbidding" and "payment of high prices" for new gas by interstate pipelines.

Earlier sections of these Comments emphasize that the gas purchase operations of each pipeline are dictated by its individual long term needs in the light of its reserves, deliverability, location and many other factors and that demand at any given point in time is only one factor among many.

The statement in the Draft assumes that demands will be reduced by far greater amounts than will result from present rates and that these reductions will exactly track the respective needs of this or that pipeline. This assumption is far-fetched, as pointed out above.

(d) "Reallocation of available supplies".

This statement in the Discussion Draft assumes, of course, that these new and untried rates will transform and level out the demand-supply relationships across the Nation; and, as pointed out above, this is impossible.

The supplies of each pipeline are based on individual contractual and operating arrangements, as are those of each distribution utility. Users are served in accordance with these individual supply situations; and the kinds and classes of user who are served depends on these supplies and the character of the service area.

There is no ground for assuming that the institution of economic cost rates,--particularly in view of the limitations and modifications therein required by the overall revenue requirement--, will materially alter these situations across the Nation.

(e) Conservation.

There is no ground for any assertion that these new and untried rates will provide greater encouragement for conservation than is already being achieved with existing rates.

It is, respectfully, submitted that the "Impacts" which may be expected from economic cost rates must be stated with far greater caution and circumspection than is now exhibited by the Discussion Draft.

CONCLUSION

United Distribution Companies, respectfully, request that the ERA's Report to Congress be modified in accordance with the foregoing comments.

Respectfully submitted,
UNITED DISTRIBUTION COMPANIES

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AFFIDAVIT

Commonwealth of Massachusetts)
County of Barnstable) ss.

C. William Cooper being first duly sworn deposes and says that he is the Vice Chairman and General Counsel of United Distribution Companies, that he has had over thirty years of experience in distribution, pipeline and producer rate and operating matters, both as an official of and attorney for gas distribution companies, that he has prepared the foregoing comments in consultation with members of UDC, that the statements therein set forth are true and correct to his best information, knowledge and belief and that he is duly authorized to execute and file the same with the Economic Regulatory Administration on behalf of UDC.

C. William Cooper
C. William Cooper

Subscribed and sworn to before me this 10TH day of
APRIL, 1980.

Paul S. Zink
Notary Public

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

792225 A

before the
Economic Regulatory Administration

Gas Utility Rate Design Study) Docket No. ERA-R-79-22

COMMENTS OF
ASSOCIATED GAS DISTRIBUTORS
ON PRELIMINARY DISCUSSION DRAFT OF
GAS UTILITY RATE DESIGN STUDY

The Associated Gas Distributors (AGD)*/ hereby submits comments on the preliminary discussion draft of the Gas Rate Design Study as requested by Dr. Stephen Skjei on March 21, 1980. With the exception of introductory remarks, these comments are organized by chapters, corresponding to the several chapters of the Economic Regulatory Administration's (ERA) draft report. The parenthetical references are to page numbers in the relevant chapters.

INTRODUCTION AND FUNDAMENTAL CONCERNS

Dr. Skjei's March 21 transmittal memorandum notes that the discussion draft does not include either a comparative analysis of the alternative rate structures or final conclusions on DOE's assessment of the various rate structures. Both of these items are of obvious and critical concern to AGD and

*/- A list of the AGD member companies is attached as Appendix A.

other interested parties and should be released for comment before the study is transmitted to Congress. The letter and spirit of Section 306 of the Public Utility Regulatory Policies Act (PURPA) call for meaningful public participation in the rate design study. To deny public comment on this most critical component of the study would not be consistent with DOE's responsibilities under Section 306. Thus, AGD respectfully urges ERA to release its conclusions for public comment at the earliest possible time.

Numerous specific points of error are made in the draft report. Many are noted and discussed later in these comments. There are, however, several fundamental concerns which pervade the entire report and warrant special attention. These involve the following areas:

1. Elasticities

The specific elasticities used in the study have a direct and substantial bearing on the results obtained. In many ways, they in fact control the results obtained. Accordingly, the study should provide information about the elasticity determinations sufficient to permit accurate assessments of them as well as the study's underlying validity.*

*/ We recognize that ERA's January interim report sought to explain the elasticity coefficients in Appendices A and B. On page B-5, for example, the demand adjustment lag model used to produce (footnote continued on next page)

At a minimum, answers to the following questions are necessary:

- What is the primary source of the elasticity factors?
- Who specifically calculated the elasticity factors?
- What is the data base upon which the elasticity factors were calculated?
Over what time period is the data from and who specifically compiled it?
- What studies have been done to verify or substantiate the elasticities used?
- How and on what basis were elasticities separated among the various blocks of the several rate forms?
- What assumptions underlie the elasticities used?

2. Conservation

In several respects, the report's treatment of conservation impacts is inadequate and unrealistic. First, the report does not appear to give any weight to non-price factors affecting conservation. The impact of conservation initiatives

*/ (footnote continued from page 2)

residential elasticity estimates was described and justified on the ground that the results fell within the range obtained by other studies, cited at page B-6. However, these other studies (a) are based upon historical periods, while the ERA model looks to the future when gas costs will be significantly higher, (b) develop long-run elasticity coefficients when the ERA model requires annual demand adjustments, and (c) apparently develop one long-run elasticity coefficient per customer class and, therefore, cannot support the 15 elasticity estimates needed for calculating total residential demand or the 36 needed for calculating total industrial demand.

by utilities and State and federal authorities has been significant, and there is every indication that this will continue. The Residential Conservation Service Program and the multitude of State and local efforts simply cannot be ignored. Second, the report appears to assume that conservation is endless. To the extent that elasticity coefficients reflect conservation, they should diminish over time as conservation reaches its limits. Finally, it cannot be assumed that consumers, particularly residential, will respond to a marginal tailblock rate. Generally speaking, experience indicates that consumers tend to respond to their total bills, rather than any marginally derived portions thereof. Accordingly, ERA should not assume a response contrary to this reality without, at least, first conducting reliable statistical surveys on the matter.

3. Equity

Overall, the study appears to equate "equity" with marginal cost pricing by definition. The "how and why" of this approach is ostensibly founded upon niceties of economic theory. The concept of equity in rate-making, however, deserves substantially more explication than this.

Inevitably, one consumer's equity is another's hardship. In part, it is for this reason that utility rates based upon cost of service have traditionally been considered "equitable." That is, it is generally believed that a "fair" or "just" utility rate is one which bears a high degree of correlation to the

cost of providing utility service to a relatively homogeneous group of consumers. And, it may fairly be said that as utility rate-setting departs from this cost of service concept a higher degree of arbitrariness enters into the process.

Certainly, such laudable national goals as conservation, reducing oil imports and improved efficiency in energy allocation may be considered in the rate design process. But, to the extent that these considerations elicit rates at odds with cost of service principles, the rate-setting process becomes significantly more fraught with political judgments. In AGD's view, this is inappropriate. Ultimately, Congress will address the issue. Hopefully, it will agree with AGD's judgment and leave consideration, vel non, of marginal cost pricing to the States, where public accountability for the political notions of equity inherent in that rate design technique is more keenly focused and difficult to elude.

4. Diversity of the Industry

Once again, we must strongly object to the very limited breadth of the study in terms of diversity of the gas utility industry. Four "synthetic" distributors cannot reasonably portray the whole of the industry. Yet, ERA has not only insisted upon this approach, but compounded the problem by extrapolating the conclusions reached as to those synthetic distributors in a wholesale manner to all distributors. Moreover, these conclusions are not regularly, and never prominently, qualified as the results of hypothetical constructs, which they are.

CHAPTER I

A number of statements in this chapter are inaccurate or misleading to the extent that summary and conclusory comments are made which leave out essential elements. The following examples are illustrative:

1. The study was not a "cooperative" effort between ERA and numerous interested parties.
(p. 1) At least from AGD's perspective, it would be more accurate to state that industry was permitted to "react" to some elements of the study as it was developed.
2. Section 306 of PURPA does not direct the Secretary to report his findings on the "implications of each approach to rate design" for conservation, equity and efficiency. (p. 1) Rather, the Secretary is directed to address the effect of several rate designs and other items on load factors, rates to class of users, demand for and consumption of natural gas, etc.
3. The report implies that the "ease of delivery" of natural gas is less than that of other fuel sources where pipes have not been laid. (p. 2) In fact, delivery of gas, as compared to delivery of most energy sources, is superior regardless of whether pipes have already been laid.
4. The report concludes that in a free market, the prices pipelines charge distributors would fully

reflect marginal costs. (p. 2) Aside from the fact that this conclusion is obviously not a "reason for the study," it is also wholly unsubstantiated economic theory and should be forthrightly recognized as such or deleted.

5. The prices paid by interstate pipelines for much of their supplies have, contrary to the draft, risen quite dramatically over the past decade. (p. 2) This fact is illustrated in the draft report itself at pp. 20-21 of Chapter II. Further, the wellhead price of natural gas has increased approximately tenfold from 1971 through 1980.
6. Given ERA's negative regulatory policy toward natural gas imports and the relatively small national supply role played by those imports, the draft's "particular concern" that their price is not fully reflected in prices pipelines charge distributors is overstated. (p. 2) Whether this "concern" is justified at all must begin by analysis of supply mixes of specific pipeline systems and specific gas distribution companies.
7. Gas distributors are not only "allowed" to base rates on average costs, they are required to do so to avoid undue price discrimination among customers. (p. 2)

8. While a Distributor's cost of gas may not drop as the volumes provided increase, its cost of service, which is the "product" being sold, does decrease relative to volumes consumed. (p. 3)
9. This section leaves the strong impression that cost of service pricing is primarily responsible for low natural gas prices at the burner tip when, in reality, the burner tip price is a function of price regulation exerted at all levels of the domestic natural gas industry -- producer, pipeline and distributor levels.
10. Unless the issue is total federal and State de-control of the natural gas industry, changes in pricing policies and price mechanisms are made by administrative action. (p. 3)
11. The description of the study "approach" does not sufficiently emphasize the hypothetical nature of the model upon which the study is based. The study does not provide insights into what "will" happen under alternative rate designs; it provides one organization's construct of what "could" happen given a multitude of assumptions which may or may not apply to any particular distribution company. (p. 5)
12. The March draft of the study report was distributed without final ERA conclusions. (p. 5)

While some of these items may seem insignificant, they nonetheless establish a tone and predisposition contrary to the desires of Congress in Section 306. This draft report leaves little doubt that ERA will recommend that Congress do something to implement marginal cost pricing in the natural gas industry. While ERA may or may not so recommend six months after the study is completed, it is highly inappropriate and disfunctional to permit this conclusion to so bias and color the Section 306 study that only negative aspects of cost of service pricing and only positive aspects of marginal cost pricing are emphasized. The draft study proceeds from the outset in this fashion.

CHAPTER II

There are numerous statements in this section which merit further explication, clarification, modification or emphasis. These include:

1. Strong economic incentives for conservation are present under current rate structures. (p. 7)
2. Time and time again AGD has sought a thorough description of elasticities used in the study. This should be included to permit analysis of the veracity of conclusions reached. (See, e.g., p. 7)
3. Producers are permitted to sell gas to the interstate and intrastate markets. (p. 10) Any given

producer will usually have such a mix of sales.

4. The description of the regulatory rate-setting process is grossly oversimplified. (p. 13)
 Aside from the mechanics of calculating a rate structure, the study should include a discussion of the multitude of forces at work in the process, e.g., State commission staffs, "public interest" groups, large consumers, cities, etc.
5. The study must take into account that the NGPA prices are ceiling prices; the impact of FERC Order No. 23 and its progeny should be carefully assessed in this context. (pp. 16-17)
6. Not all outer continental shelf gas is "new" under NGPA. (p. 17)
7. The "ability" of interstate pipelines and distributors to "roll-in" higher cost gas is severely restricted by the NGPA, which requires that the most price sensitive customers be incrementally priced. By contrast, NGPA incremental pricing is not applicable to the intrastate markets. The draft study skirts these facts. (p. 18)
8. It is untrue to state as an absolute that "pipelines assume little risk in purchasing higher cost gas" (p. 20).
9. The idea that pipeline contracts with distributors "carry on federal controls for years"

cannot be blithely stated without analysis of those contracts. (p. 20) Clearly pipeline service is constrained by contracts, but price is quite another matter. PGA and section 4 general rate increases do not take long to send the message of higher pipeline prices to ultimate consumers. The study's discussion of these matters is grossly simplified and not reflective of actual operations.

10. The "cost of meter reading and billing is" not "assumed equal for each customers," but, rather, for each class of customers. (p. 24) The bulk of the description of traditional ratemaking at p. 24 is inaccurate and misleading.
11. A third important upshot of curtailment is that gas distributors themselves augmented their own supply sources supplemental to their traditional pipeline sources. (p. 26)
12. Current rate patterns cannot be accurately analyzed in today's world without recognition of NGPA-mandated incremental pricing. The draft study fails to discuss rate patterns in this context, particularly with respect to Rule II, NGPA § 202. (pp. 26-27)
13. The source for Table II-5 should be provided. (p. 27)

14. Large users do not pay less than residential customers; their average rate is less. Further, factual substantiation is not presented for the conclusion that this price structure "tends to encourage added consumption" by those most able to switch fuels. (p. 27)
15. A distributors' preference for United or Seaboard is highly dependent upon its relationship with its customers and cannot be accurately generalized as broadly as the study purports. (p. 22)

CHAPTER III

The numerous misstatements and questions raised in this section are as follows:

1. NGPA does not broadly mandate "the deregulation of wellhead natural gas prices in 1985." Some categories are deregulated, most are not, and, in any event, contract authority to collect higher prices must be present. (p. 3)
2. Again, the impact of FERC Order No. 23 and its progeny is not assessed. (p. 3)
3. Nowhere in the draft study is there any data base presented as to the contractual relationship between intrastate pipelines and producers vis-a-vis those pipelines ability to "roll-in" higher cost supplies. (p. 4)

4. The study does not explain how non-exempt, incrementally-priced industrial users will "find natural gas a 'bargain.'" (p. 5) The effect of NGPA incremental pricing (the whole of Title II) cannot simply be ignored.
5. The study assumes "inadequate levels of conservation." (p. 5) Conservation has clearly been a significant factor in recent years in natural gas markets. The study cannot graciously brand this "inadequate" without some basis in fact.
6. While the study emphasizes that average cost pricing "may" obscure the economic cost of gas (p. 6), it does not present the other side, i.e., that average cost pricing, given dramatically increasing wellhead prices and their proportional weight in determining cost of service, may well provide at least something close to the price signals sought under marginal cost pricing.
7. The conclusion that, if pipeline and distributor rates reflect marginal cost, then consumers would either conserve more or switch to lower priced fuels (p. 7), ignores a very real third consequence -- consumers may simply pay more for gas utility service.

8. The study states that the "key concern" of rate design is to prevent the occurrence in 1980-84 of the misallocation and economic losses of the 1970's. (p. 8). As so defined, little if any room is left for any rate design but marginal cost pricing from a national perspective. Nowhere, however, does the study get to the particulars of how exactly this is to come about without anything less than federal fiat. It is submitted that there are very substantial "key concerns for rate design" at a State level which the study simply fails to recognize or address in anything more than ipse dixit reasoning -- i.e., what is assumed good energy policy at the federal level must be right for the States. This approach is cavalier at best unless significant benefits can be achieved which would not otherwise be achieved. The study does not quantify these "misallocations" and should do so if the intention is to radically reform rate-making, as it seems to be.

CHAPTER IV

Basically the concerns with this section fall into several categories. First, the analysis proceeds from the assumption that "accounting cost based" rates are misguided. Thus, rather

than even attempt a balanced description of the function and purpose of these rates, the study becomes an advocacy tool for predicting the consequences of this rate design approach which are seen as incompatible with the study's assumptions for "appropriate" national energy policy.

Second, the study frequently makes sweeping conclusions of what is "good" or "bad" based upon relatively insignificant distinctions between the rate forms analyzed. These distinctions are made without any regular qualification or caveat as to the scope of distributors studied or variety of market circumstances faced by different distributors throughout the country.

Third, conservation assumptions are not detailed. Specifically, neither the calculation nor verification of elasticities are disclosed. These are very important elements of the study, and ERA has steadfastly refused to provide the degree of detail necessary to assess the accuracy of its elasticity calculations.

Fourth, revenue stability is given extremely cursory treatment. It is dismissed as "a subject for decision in the individual case of a specific utility." (p. 37)

Lastly, the final report should include the cost of service study used herein as well as a description of the assumptions underlying that study.

CHAPTER V

Regardless of potential adverse specific impacts, p. 13, this chapter of the "study" is dedicated to the proposition that marginal cost pricing (MCP) is the "answer." Thus, it is not surprising that little or no effort is expended in detailing the problems and unfulfilled promises of marginal cost pricing. What are the administrative costs to consumers of a shift to MCP? Are the "benefits" of MCP so significant that it should be implemented to achieve only short-range objectives? What is the budget-billed consumer's response to MCP? What is the factual basis for the view that "consumers" respond to MCP more positively than to average cost pricing given rapidly escalating gas costs anyway? Precisely how was the MCP used herein derived? How can all gas costs to distributors reasonably be assumed as variable given real-world gas purchase contracts? These and a host of other issues are simply not discussed or detailed.

At best, Chapter V applies economic pricing theory to three hypothetical distributors and obtains conflicting signals. This weakness leads to seriously questionable "benefits" of MCP even from a "National Impacts" perspective. (p. 31) For example, the "smooth transition at the time of decontrol" benefit assumes MCP in 1978 to achieve the absence of a price "spike" in 1985. Query: Is not a "spike" merely brought about earlier? Second, nationwide application of real resource

cost rates can have severe adverse revenue stability consequences which the ERA model conveniently assumes away by defining all gas costs as variable. Third, by restraining price levels of decontrolled gas, is not supply restricted and, thus, less gas available to supply those consumers who otherwise use imported oil, contrary to the national interest? Finally, the improved allocation benefit is hardly substantiated sufficiently to warrant pipeline and distributor MCP nationwide. Moreover, it is quite unrealistic to expect regulatory authorities to permit value of service pricing to allocate gas utility service from residential customers, unable or unwilling to pay prices so generated, to larger or richer customers who are willing and able to pay such prices.

* * *

AGD appreciates this opportunity to comment on the draft rate design study and respectfully urges ERA to respond substantively to this critique in the final study.

Respectfully submitted

ASSOCIATED GAS DISTRIBUTORS

By
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Dated: April 11, 1980

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Baltimore Gas and Electric Co.
Bay State Gas Co.
The Berkshire Gas Co.
Boston Gas Co.
Bristol & Warren Gas Co.
The Brooklyn Union Gas Co.
Cape Cod Gas Co.
Central Hudson Gas & Electric Corp.
Chesapeake Utilities Corp.
City of Holyoke, Mass., Gas & Electric Dept.
City of Westfield Gas & Electric Light Dept.
Commonwealth Gas Co.
Concord Natural Gas Corp.
The Connecticut Gas Co.
Consolidated Edison Company of New York, Inc.
Delmarva Power & Light Co.
Elizabethtown Gas Co.
Fall River Gas Co.
Fitchburg Gas & Electric Light Co.
Gas Service, Inc.
Haverhill Gas Co.
Long Island Lighting Co.
Lowell Gas Co.
Lynchburg Gas Co.
Manchester Gas Co.
New Bedford Gas & Edison Light Co.
New Jersey Natural Gas Co.
New York State Electric & Gas Corp.
North Carolina Natural Gas Corp.
Northern Utilities, Inc.
The Pequot Gas Co.
Philadelphia Electric Co.
Philadelphia Gas Works
Providence Gas Co.
Public Service Company of North Carolina, Inc.
Public Service Electric & Gas Co.
South County Gas Co.
South Jersey Gas Co.
The Southern Connecticut Gas Co.
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April 22, 1980

Ms. Janet Grimes
U.S. Department of Energy
Economic Regulatory Administration
2000 M Street, N.W.
Washington, D.C. 20461

Dear Ms. Grimes:

Enclosed please find our final report entitled, "Comments on the United States Department of Energy Natural Gas Rate Design Study Pursuant to Section 306 of the Public Utility Regulatory Policies Act of 1978". We will forward invoices when we receive them.

I would appreciate it very much if you would forward the final copy of the DOE study together with all the appendices to me as soon as possible.

It was a pleasure working with you and your staff on this and I look forward to similar occasions in the future.

Thank you very much.

Very truly yours,

NEAL RAUCH
Assistant Attorney General
Energy & Utilities Section

NR:MS
Enc.

COMMENTS ON
THE UNITED STATES DEPARTMENT OF ENERGY
NATURAL GAS RATE DESIGN STUDY
PURSUANT TO SECTION 306 OF THE
PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

Submitted by:

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April 18, 1980

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I. Executive Summary

The New York State Department of Law concurs with the findings of the DOE study that marginal cost based natural gas rate designs best meet the mandates of the Public Utility Regulatory Policies Act of 1978 (PURPA) as set out in Section 301(a).

There are problems, however, which must be resolved before deciding to implement natural gas rate designs based on marginal costs. These include:

1. determining whether the costs of implementing such rate designs exceed their benefits;
2. determining a procedure for estimating marginal costs;
3. reconciling discrepancies between a utility's revenue requirement and potential excess revenues received when rates are based upon marginal costs.

The New York State Department of Law recommends that future research, as outlined in our full report, be undertaken to resolve these questions.

II. Scope of Comments

Section 306 of the Public Utility Regulatory policies Act of 1978 (PURPA) mandated a study of rate design for natural

gas with an eye toward promoting economic efficiency. A primary objective of the mandated study is to assess the merits of various possibilities for the design of rates for natural gas, such as those based on average versus marginal cost. As simple as it may seem, this is rather a broad mandate; and the task it describes is a substantial one. With respect to the different sorts of rates, there are many different kinds of customers they would effect. There are the obvious broad groupings into residential, commercial, and industrial customers, but different utilities have different mixes of these three groups so it is very difficult to make general statements about the effect of rate design on utility customers. In addition, the configuration of costs obviously varies from utility to utility, in large measure depending upon locational factors. Third, numerous possible rate forms can be analyzed, such as flat rates, seasonally differentiated rates, marginal cost based rates, inverted rates, and so on. A study which can be used to make general statements about the design and effects of various natural gas rates on a national basis represents a substantial undertaking.

The DOE sponsored study reviewed represents a laudable effort to satisfy this mandate. Its authors have modeled several different types of utilities with different

types of customers facing numerous supply conditions for natural gas and having different cost configurations, and they have analyzed a number of different rate forms. As a general observation, the study probably comes about as close as is reasonably possible to satisfying the extremely broad task mandated by Section 306 within the allotted time.

The analyses performed in the study address either traditional rate designs (the status quo) or 'reforms' of rate designs (which reforms usually mean marginal cost based rates). It is clear that one of the objectives of Section 306, and the PURPA in general, is to suggest appropriate responses to "the energy crisis". Among the possible responses are "rate reform". One notable absence from this study is an assessment of whether "rate reform" is worth the effort. That is, when we study different rate forms, among the things we would like to know is whether consumers derive any benefit in either the short or the long run from changes in the design of rates. Although marginal cost pricing has been presented by some (including the study's author) as the obviously appropriate direction for rate reform, it is not unambiguously clear that a change to marginal cost pricing would lead to substantial benefits for consumers of natural gas. (For example, a study done by the authors of this review found that in 1970 the net benefit, in consumer surplus terms, to residential-consumers of electricity of a switch from average cost to marginal cost based rates would amount to about 25 cents per month per household.

This study was done with reference to residential customers and it is probably true that the benefits to industrial customers would be substantially higher. These benefits, however, would vary depending on what 'definition' of marginal costs is used).

The following sections present detailed comments on the DOE study of gas rate design from the perspective of economists. For example, there are no comments upon assumptions about, or models of, cost conditions from the supply side of the natural gas market. Nor is the rather elaborate industrial gas demand model discussed. (However, it is worth noting that the time frame for switching between fuels which occurs in the industrial demand model is not specified. The authors do not make clear whether a switch from gas to oil or oil to gas can be done in the span of a week, a month, or a year. Moreover, they do not mention, and it is not clear, whether the same amount of time is usually required to switch from gas to oil as it is to switch in the opposite direction).

Several broad issues in the DOE study are of concern. A major consideration, not dealt with at length, is the proper time frame for the marginal cost estimates used in Chapter V of the study. Marginal costs are defined fairly precisely in this section, but the authors do not make clear whether they prefer a long-run or a short-run definition. In the study's

analysis of demand, the models used contain a number of shortcomings. These have been detailed in earlier interim reports (See Appendix, p. 42). Below, are some additional comments about the demand models. The demand models are probably the weakest part of this study. However, given the complexity of modeling customer demand, this is to be expected. Finally, in Chapter V, the market analysis relies upon a crucial assumption about the price of natural gas and its relation to its nearest alternative, oil. Comments on this issue are fairly lengthy.

Limited comments on narrow issues, such as the definition of various terms or the organization of the text, are presented in this review. The study was well organized but the quality of the exposition was somewhat uneven. Some sections were too long, while other were too short. At the same time, Chapter IV relies very heavily on tables, while the last chapter tended to ignore them despite the obvious relevance to the material in the text. The discussion would likely benefit from some summary tables included in the body of the text. These would be useful if it were possible to distill some of the information in the appendices. For example, the discussion may include the presentation of some broad averages over the various customer groups or over the various types of utilities analyzed.

Section 306 of PURPA mandated a gas rate design study to provide overall broad assessments of the effects of changes in the pricing of natural gas. Clearly, better information could have been obtained if the study had been done for specific utilities, but, of course, this would not be feasible. Nonetheless, such studies could be done and the results would be a valuable source of information. It is noteworthy that one state has moved in this direction. In its Opinion No. 79-19, (Sept. 17, 1979), the New York State Public Service Commission directed that "future rate filings by all gas utilities shall include a complete analysis of the utility's marginal commodity costs and marginal capacity costs and shall explain how the proposed rate structure reflects marginal costs . . ." Brooklyn Union Gas Co., has since submitted such a study. The study we have reviewed here might, in addition to the information it provides in its own right, suggest a framework for similar studies by others on discrete utilities.

The DOE study involved the analysis of many different configurations of utilities, many different kinds of customers, and many different supply scenarios. The number of combinations of the three of these is clearly quite large. As a consequence the study required the accumulation of a tremendous amount of information. There could be a problem of organizing and presenting all of this information in a coherent fashion.

The report represents a good job. The comments below indicate the weaknesses in the study of some suggestions aimed at improving the presentation.

III. Responses to Specific DOE Questions Concerning its Rate Design Study*

A. WHAT MAJOR ISSUES ARE NOT ADEQUATELY ADDRESSED?

Natural gas rate designs that rely on marginal costs have several practical difficulties. These practical difficulties are not given sufficient detail in the report. At the very least, the report should be candid and admit that these difficulties do exist, and are not addressed. These difficulties include:

1. How are marginal costs to be estimated?

Specifically, what time horizon is to be used in the estimation of marginal cost, (i.e. long-run or short-run marginal costs, some intermediate run, or compromise between the two)? These difficulties must be faced before any marginal cost rate design can be adopted.

* In the cover letter of March 21, 1980, Dr. Steven Skjei, of the Economic Regulatory Administration of DOE, specifies several questions of particular interest to DOE. This review responds to most of those questions in detail in the body of the report immediately following this section, and only a summary appears in this section.

2. If marginal cost based rates lead to revenues that are substantially in excess of traditionally determined revenue requirements, some mechanism must be adopted for returning these "excess revenues" to the customers. The report does not discuss the alternatives in any detail: the alternatives include (at least) reduction or elimination of customer charges, inverted rates, reconciliation based on inverse elasticity considerations, and customer rebate schemes. If customers react only to their total bills, and not to the marginal rate, these alternatives will have different implications for conservation. The report should at least acknowledge that these questions exist, and that these questions must be addressed before marginal cost rates are actually implemented.
3. The alternatives listed in paragraph 2 above have different implementation or administrative costs, and these costs must be considered

in deciding which alternative to choose when revenues greatly exceed revenue requirements under marginal cost based rates. The cooperation of gas utilities would be very useful in conducting research aimed at 'solving' this problem.

B. HOW WELL ARE VARIOUS ISSUES TREATED? HOW CAN THE DISCUSSION BE IMPROVED?

As set out in Section IV herein, Chapters IV and V of the study need to be extensively rewritten, Chapter IV is excessively detailed: there are far too many tables and too much information for any reader to comprehend. On the other hand, Chapter V makes little specific use of the tables which follow it. Some of the tables should be integrated into the chapter, and the others should be referred to by number in the text of the chapter. Other than these two chapters, the report is well written. Of course, the report certainly needs a "conclusions and recommendations" section.

C. WHERE IS THE DISCUSSION IN THE REPORT INAPPROPRIATE OR MISLEADING?

As stated in detailed comments following this section the assumption that the price of natural gas will float to the BTU equivalent price of imported oil may be correct: but on

the other hand it may not. How confident are the authors that this assumption is correct? What will happen if sufficient supplies of natural gas are found at a low enough cost to keep the market price for natural gas below the BTU equivalent price for oil? How sensitive are the results to this assumption? All of these issues should be addressed in the report, (See pp. 15-19, Note 13, ante).

The structure and format of the report are satisfactory. Its size seems about right: however, the authors may want to make detailed simulation runs available to the interested reader. If this is done, they should be provided in an indexed form.

The labeling for the different company types might be improved if the authors were to adopt regional, rather than the cost designations. For example, rather than refer to their first case as the "Moderate Cost Utilities", they could refer to this case as the "Midwest Utilities". They would need to carefully explain this designation, as they have done on Page 4 of Chapter IV. This designation should be adopted only if the moderate cost case is fairly typical of midwest utilities.

IV. Comments on the DOE Natural Gas
Rate Design Study

Chapter I - Introduction

1. Page 2, second complete paragraph: The wellhead price of natural gas has not "remained close to level set a decade or more ago." The real price, corrected for inflation, has probably remained constant, or has even fallen. But the distinction between real and nominal prices is not made here, and the statement given is incorrect. Also, later in the paragraph the word "unregulated" might be inserted between free and market.

Chapter II - Current Patterns of Demand,
Supply and Regulation in the
Natural Gas Industry

2. Page 3, second complete paragraph: Why not state precisely what the Power Plant and Industrial Fuel Use Act of 1978 does require. It is not clear what is meant by "in general cease using natural gas". Why not say, presuming that it's true, that they can no longer use it as a boiler fuel - to generate electricity.

3. Page 7 , first paragraph: If a conservation measure takes ten years to return its original cost in gas savings, the rate of return in the investment would be below 6% (in real terms). The numbers should be re-examined and a more reasonable example picked.
4. Page 8 , second paragraph: What are the substitution possibilities for process uses of natural gas? The reader is left dangling after this paragraph.
5. (Deleted)
6. Page 13, first complete paragraph: Are the Authors sure that the interruptible customer does not incur high costs? That is, the text states that the use of interruptible customers to meet peak demands is not a high-cost alternative. Considering that these customers must switch to alternative fuels or shut down, it's not clear that the social costs of this form of meeting peak demand are low. Furthermore, the utility's "costs" should include the revenue loss during the entire year by not providing these customers with firm service. When these two factors are taken into account, it's not clear that the use of interruptible customers is a low-cost alternative.

7. Page 17 , last paragraph, last sentence:
Figure II-1 says nothing about prices for oil and new gas between 1979 and 1985. Figure II-1 is an overview of the U.S. natural gas system.
8. Page 20 last complete sentence: The estimate of gas costs to the pipeline in 1978 should be checked, a price of 1.06 cents per mcf seems a bit low.
9. Page 24 , last paragraph: The high proportion of non-gas costs that are assigned to residential consumers are assigned not because there are large number of residential customers, but rather because they consume a large quantity of gas. Also, the authors may want to point out here that the results of a cost of service study have, in general, very little to do with the cost of supplying more gas to individual customers, or the savings from conservation by individual customers. The results of a cost of service study are not the marginal costs but rather some arbitrarily defined average cost.
10. Chapter II ends rather abruptly. Right in the middle of a discussion of rate structures, the reader turns the page and finds Chapter III. It would be advisable

to discuss current rate structures more fully, especially by considering their seemingly arbitrary nature. The statement in the last paragraph that the current price structure encourages added consumption by the customers most able to switch to alternate fuels needs explanation. Furthermore, it would be useful to discuss the historical reasons for the current rate designs, and to discuss whether or not they are likely to make economic sense.

11. Chapter II was, in general, well written, and thorough. The only item missing was a discussion of gas production. The operation of the natural gas industry from the pipelines onward is discussed in sufficient detail, but gas production is almost never mentioned. A discussion of numbers of wells drilled per year, and the way that this drilling activity has been influenced by FERC and FPC policy would be useful. The types of risks entailed, and the identity of the individuals and corporations engaged in drilling activity, should also be discussed.

Chapter III - Major Study Issues

12. Page 4 and bottom of the first full paragraph: After stating that the intrastate pipelines would be at a disadvantage (have higher costs and thus higher prices) relative to the interstate market, the paragraph concludes with the statement "gas may flow from the interstate

to the intrastate markets." The underlined words apparently should be reversed.

12A. Page 5, first paragraph: The authors are mixing apples and oranges in this paragraph by comparing the \$15.00 adjusted per barrel price in 1985, which is an inflation-corrected price, with the current nominal price of \$30.00 per barrel?

12B. (14 - deleted)

13. The reasoning at the top of page 9 should be strengthened somewhat. The first two paragraphs on that page appear to argue that the marginal cost of natural gas to the nation is the price of its principal substitute - imported oil. While this may be true, it is not a simple argument.

Referring to Figure I, of this report, the argument could be made as follows: In an unregulated market, with the demand schedule for natural gas represented by DD and a supply schedule for natural gas represented by SS, the equilibrium or market clearing price would be $O-P_{mkt}$. Producers, reacting to this market-determined price P_{mkt} would produce quantities of natural gas up until the point when their marginal cost of producing another mcf of gas was P_{mkt} . Beyond that point, with their costs in excess of P_{mkt} , additional production would be unprofitable. For this reason, in an unregulated market, the marginal costs of additional production of natural gas would be P_{mkt} .

However, over the period of 1978 to 1985, the price of natural gas will be regulated at an artificially low level, represented by P_R in Figure I. At this lower

regulated price, quantity demanded is O-C, while the quantity supplied is the lesser amount O-A. A shortage of A-C will appear. The problem facing the regulators, and the sense in which the marginal cost of natural gas reflects the price of imported oil can be seen by attempting to allocate the quantity O-A of natural gas among those individuals who would like to purchase that natural gas, represented by O-C in Figure I. If the regulatory system is perfectly effective, in the sense that the operation of a competitive industry is replicated perfectly, the users who are denied the use of this gas will be the users who place the lowest value on it. Those users are represented by all demanders from A to C in Figure I. If that is the case, then the gas will be allocated to the highest value users, represented by O-A in Figure I.

Then the question can be asked, what is the value or marginal cost of an additional mcf of gas? To answer this question, we must first realize that, among those users who do not receive natural gas, even though they would like to purchase natural gas at the regulated price $O-P_R$, the user placing the highest value on this natural gas is the user at A. That user would pay a price O-E if he were able to purchase natural gas.

Because he has been denied natural gas by the rationing or some other allocation scheme, the user at A must turn to alternative supplies, and the value that he would be willing to pay (O-E) reflects the costs he incurs by turning to these alternative supplies.

Figure I

So if we envisioned the marginal cost of natural gas in this shortage situation to be what individuals currently denied natural gas would be willing to pay were they able to get natural gas, then the marginal cost of natural gas is clearly dictated by the alternatives these potential users must adopt. Assuming that the alternative chosen by the potential users who places the highest value on the natural gas is imported oil, which is represented by the price or opportunity cost $O-E$, then the marginal cost of natural gas to society is $O-E$, or the BTU equivalent natural gas price of imported oil. This is necessarily true, however, only in an artificially induced shortage, which results when a price ceiling of $O-P_R$ is placed on natural gas. The truth of the statement also depends on the assumption that the best alternative facing the customer at A is oil, and not coal or some other energy source. Finally, whether the marginal cost of natural gas in an unregulated market (e.g. post 1985) will be equal to the price of imported oil depends on the supply schedule as well as on demand conditions. Under the admittedly arbitrary diagram shown, the supply elasticity is sufficiently high to result in an equilibrium price below imported oil costs in an unregulated market. Of course, it might be that the equilibrium price in an unregulated market would be $O-E$, the equivalent BTU price of oil. Accordingly, the authors should be more careful to spell out the circumstances surrounding their statements at the top of page 9

Under what conditions will that assumption be reasonable? Is it possible that the price of natural gas will be less than the price of high-sulfur residual oil? What factors would cause this lower price to occur?

14. The closing part of Chapter III is essentially an introduction to Chapter IV. This introduction could be more thorough: The authors should explain what they are going to do with these alternative scenarios. They describe in some detail what the price assumptions will be, but what will be the output of this simulation?

Chapter IV - Accounting Cost Based Rates

15. Page 3 - second full paragraph: Present FERC procedures call for 25% of the fixed costs to be allocated to the demand charge, not the "fixed charge" as stated in the second to last sentence in this paragraph.
16. The beginning of Chapter IV needs revision. The early part of the chapter now discusses different types of rates, describes in too little detail a survey of large gas utilities, states that the simulation will be applied to three types of utilities and then presents the results of this simulation. The reader is given very little information about how the simulation actually works. An intelligent and interested reader will want to know just what is inside this "black box" that produces all these numbers. Anyone who has undertaken a simulation analysis of their own will naturally be suspicious, and will

realize that the model builder can force the simulation model to produce nearly any results that he or she wishes. Some detail must be provided on the workings of the model. Otherwise, the readers only response will be well deserved skepticism.

17. The results of the model are given on page 5-40, a total of thirty-six pages: twenty-four tables appear on these thirty-six pages: two-thirds of the pages have tables on them. Do the authors really believe that anyone can retain and process the information contained on twenty-four different tables? So much information is presented in this chapter that it is difficult to retain any of it.

The chapter needs to be re-written entirely. There should be a section at the beginning of the chapter which describes what the model does in some detail, and also a few brief sentences in the introduction to the chapter which describe the results of the simulation. A conclusion to the chapter should be added which summarizes the findings, and points the reader to what the authors feel is the most likely scenario. In between the introduction and conclusion, the authors should be much more selective in presenting results. The authors should select what they feel is important information, and include only those tables. There should not be more than ten tables in this chapter.

If the authors really believe that all of these tables are necessary, they should be placed in an appendix to the chapter (or to the entire report). Assuming that the purpose of this report is to get information across to the Congress and to the general public, chapter IV should be re-written.

18. At the top of page 19, the authors should make clear what price per barrel is equivalent to a price of residual fuel oil of \$4.43 per dth.
19. After reviewing this chapter's discussion on fuel switching by industrial customers, and conservation by residential and commercial customers, it is apparent that the authors need to describe briefly their assumptions about demand elasticity. With respect to industrial customers, does the simulation model assume that all industrial customers switch at the instant that the price of natural gas is equal to the price of fuel oil? What is the long run demand elasticity for residential customers? Are these assumptions conservative: are they widely accepted by the other economists working in the area? What are the consequences for the model's results if the assumptions are changed slightly?
20. The discussion in the paragraph at the top of page 33 hints at an interesting issue, but doesn't develop it. Has the use, by gas distribution utilities, of interruptible customers for the purpose of leveling load

over the year, lead to a non-optimal method of production and distribution of gas? Would it be more economical to have the rate of production of gas by the producers, and the rate of transportation by the pipeline companies, vary over the load cycle, rather than the prevalent constant rate of production in place today? It may be that one cost of having regulated prices below market clearing levels was that the producers had an unusually strong bargaining position, and were able to force their will on the pipeline and distribution companies with respect to rates of production during the year. If so, DOE may want to consider encouraging a change in this practice if such a change is economically justified.

Chapter V - Marginal Cost Based Rates

21. The discussion on page V-5 and 6 of inverted block rates for pipelines is perplexing, and probably incorrect. The authors imply that gas distribution companies will change their rate schedules in response to pipeline company rate schedule changes. There is a great deal of inertia in the gas distribution utility business, and it is unlikely that the gas distribution companies would change their's. The example is given that the distribution companies would raise their tail-block rates if the pipeline companies raise their's, "otherwise they would be charging some customers prices for gas which were less than the prices they were actually paying." But this is exactly what is happening now

with average cost based rates, and the distribution companies don't appear inclined to change their practices. They currently charge some customers much less than their marginal costs of securing supplemental supplies (such as SNG), and don't appear anxious to change this policy.

22. It is questionable whether full wellhead price decontrol would necessarily lead to marginal cost pricing for gas distribution companies, as is implied on page 6. Unless by decontrol the authors mean that all current long-term contracts would be abrogated, the fact that some of these long-term contracts specify prices well below the uncontrolled market price that might result would still leave the pipelines open to roll-in or average together high cost new gas with low cost old gas. Similarly, the distribution companies could roll in their different supply sources.

23. Page 7 , second paragraph, first sentence: In this sentence the authors side-step what is probably the most important problem with marginal cost pricing. What is the marginal cost of natural gas? How far into the future does the analyst look when estimating marginal cost? The authors state that they have estimated the "real resource costs of gas plus variable transmission costs": what they mean by that is not clear. At the very least, the authors should explain the disagreements that might arise over what time frame or time horizon is used to estimate marginal costs. A more satisfying approach would be to

develop those arguments extensively, and make a decision after evaluating the difficulties of estimating marginal costs under the different assumptions..

24. In the definition of marginal costs on p. 8 , some attention is paid to the issue of defining marginal costs from the perspective of the distribution company. The treatment in this section is rather like the treatment of marginal costs by electric utilities. But, in fact, as the authors appear to discover late in this chapter, this method of dealing with marginal costs is problematic. It would probably be best to dismiss this method of computing marginal costs early on in the study and not spend any more time on it. The computation of marginal cost based rates based on the distribution company's cost, when the pipeline delivered price is not based on marginal costs, either resource costs or some other measure, really makes no sense. No economically efficient signal is transmitted by passing on the marginal cost to the customer when, in fact, that marginal cost has nothing to do with real resource cost at the wellhead. Therefore, it is best that this section be dispensed with early on and not mentioned again.

25. The authors should point out, on page 8, that their distributor incremental cost rates are only marginal cost rates under the assumption that distributors can get as much gas as they desire at the prices

charged by the pipelines. These rates don't reflect marginal costs in a shortage situation.

26. The use of an inverted rate design throughout most of the Chapter V study, particularly for the pipeline companies is unnecessary. The authors have dealt with revenue shortfalls for either pipelines or distributors by using lump sum adjustments. There is no reason why the same kind of adjustment can't be made in the opposite direction, that is, when revenues are overcollected, lump sum reductions could be used. The advantage in this is that at no time does the price signal differ from marginal cost as it does in the case of the inverted rates. Another problem with inverted rates is pointed out on page 6 of chapter V in which it's noted that when the distributor must purchase gas at an inverted rate structure and sells it using an inverted rate structure it will frequently be charging customers prices which differ from the prices the distributor is actually paying for the gas. In fact, this can go in either direction. Therefore, again, the mismatch of revenue produced with allowed revenues should be dealt with using the same kind of lump sum adjustment in the revenue overcollection case as is suggested in the undercollection case.

27. Another very important problem that the authors have not dealt with at sufficient length, is customer reaction to the different alternatives for returning "excess

revenues". If customers look only at their total bill, and if this total bill is unchanged under marginal cost pricing (relative to average cost pricing), they will not change their consumption at all as prices are increased from average costs to marginal costs. If, on the other hand, customers look at their marginal charge only, then they will conserve as the marginal rate is increased. It is unclear which assumption the authors made in the simulation model, although it seems reasonable to assume they made the prior assumption.

28. The load factor of residential, commercial, and industrial customers is markedly different. These differences in load factor lead to a difference in the cost (marginal or opportunity cost) of serving these different types of customers. How have the authors handled this difference in load factor and thus this difference in marginal cost between the three types of customers? They should spell out their methodology on this issue in detail.
29. The section on customer impact of economic cost rates beginning on p. 10 is substantially too long. It can be shortened if the authors confine themselves to a single definition of marginal cost and perhaps a bit less detail with respect to each customer group. By and large the organization seems correct, that is, the major headings being residential, commercial, and

industrial customers and minor headings being type of utility.

30. About midway through the section (at p 12), the term "lifeline rate" appears for the first time, and is used intermittently throughout the remainder of the discussion. It seems to me that the issue of lifeline rates has never arisen in any of this discussion, and it is probably misplaced. The question of lifeline rates involves a question of income distribution, a point discussed later. For now, it is worth noting that the impact of changes in rate design upon various consumer groups has not been analyzed in this study. It is probably not a good idea to raise the issue of lifeline rates at this point unless the authors intend to deal with distributional impacts of rates specifically. In spite of the fact that inverted rates and lifeline rates are sometimes equated, the term "lifeline rate" should be scrapped wherever it appears here in favor of "inverted rates", simply to avoid the issue altogether.

31. Whereas Chapter IV presented far too much numerical information for the reader to comprehend, this chapter provides too little: All comparisons are made qualitatively. In terms of overall consistency of the report, this chapter would benefit from the addition of some tables. Qualitative comparisons of results,

such as are made in this chapter, are not very satisfying.

Perhaps the tables at the end of the chapter contain the information that is needed within the chapter.

If so, some of them should be placed within the chapter.

At the very least, some reference to these tables should be made in the report.

32. Page 21 , first paragraph: In the paragraph on rate levels, the authors refer to transmission costs. Are these transmission or transportation costs the pipeline charges? If so, are these really marginal costs? That is, considering that the pipelines are already built (sunk) and considering that there is an excess pipeline carrying capacity over what is being shipped, what is the marginal cost of shipping another mcf of natural gas? Hopefully, the authors have included only those costs that are truly variable.
33. Page 23- revenue stability: One of the main objections of the gas utilities to marginal cost pricing is revenue stability, and it is not likely that the treatment in this paragraph is sufficient to answer their objections. They feel that when the tail block rate is raised, as it would be for many of the country's utilities, revenue stability will begin to be a problem. They also feel that the time horizon for estimating marginal costs might change, as might the methodology

used for calculating marginal costs, with the result that the price for a given consumer will change dramatically over time. They believe that a possible result of this changing price signal will be revenue instability for the gas utilities. Gas utility managers should be consulted on this issue.

34. Suddenly, on page 25, the tables are being referenced for the first time. This change in style is rather abrupt and should be eliminated. (See also point 31, supra)
35. As mentioned above (point 30), the report does not contain a discussion of the distributive impact on customers of the changes in rate design. This is consistent with the primary orientation of the study to the supply side of the natural gas market. I am not sure that this sort of thing is under the author's purview. But, if it is, then the demand model, which appeared in an earlier report, would of course be useful. This would involve an analysis of income effects as well as substitution effects, particularly with reference to small residential customers. It is uncertain what information is available on the use of gas by income level or on elasticities of demand as they vary (if they do indeed vary) by income level. However, if such data are available, they could be built into a simulation model in order to assess, at least in broad terms, the distributive impact of changes

in rate design such as the use of marginal cost pricing vs. average or embedded cost pricing.

36. A related point is mentioned in a few places within the report. There appears to be a considerable difference between the class revenue allocation which results under a regime of embedded cost pricing and that which results under a regime of marginal cost pricing. A section on this topic might be worthwhile. For example, there are some interesting numbers in Table 2 which show that industrial rates tend to increase substantially when marginal costs are used to determine price. Of course, two effects would be observed. The industrials which stay on the system, so to speak, would be absorbing a larger portion of the total revenue requirements; but some industrials might choose to leave the system. In the latter event, the burden is shifted back to the other customers, including the residentials. A discussion of the net outcome might be worthwhile.
37. The discussion on marginal cost pricing would probably benefit from some verbal discussion on the differences between the rate structures as the customers would see them. Some of this information does appear in the tables which appear at the end of the section. However, a discussion would probably be worthwhile. For example, it is well known that under current regimes industrial users tend to pay substantially lower rates for natural gas, even in some settings in

which these rates cannot be justified on a cost basis. It appears that under the marginal cost pricing regime analyzed by the authors some of these differentials disappear, and, in fact, are even reversed. An overall assessment of the changes in these differentials would probably be worthwhile.

38. The section on marginal cost includes, in a number of places, the term, "incremental costs" (properly so). However, earlier in the report, there is a discussion of something called "incremental pricing". These are not necessarily the same thing, and it would probably be worthwhile to reconcile the two or drop the term, "incremental costs" in favor of "marginal costs" if they cannot be reconciled.
39. Page 31, principal benefits of economic cost rates: The most important benefit of economic cost rates is left until last and receives only a short phrase. Economic based rates encourage conservation, allocate the available gas efficiently, and reduce our reliance on imported oil. This should be stated up-front, in capital letters, with less talk about transitions and inequities between inter and intrastate pipelines.

V

CONCLUSIONS AND POLICY RECOMMENDATIONS

As indicated at the outset, this study is generally well done. Indeed, given the broad mandate of Section 306, it

is as good as could be asked for.

The authors use simulation analysis to study the various issues considered. Thus, they simulated the supply side of the market, that is, the delivery of natural gas, the pipelines, and the costs of the distributors; and the demand side of the market, that is, the responses of customers to various changes in prices and design of rates. As always, there are problems with simulation analysis. In essence, it requires assuming the answers to questions. That is, the results obtained obviously follow directly from the initial assumptions made. But, as the authors indicate, many of the scenarios they were required to study had in fact never occurred in the real world. Among these, for example, are the use of marginal cost rates and inverted rates. Given this, as they state, there really is no other satisfactory way to analyze the problem. On the other hand, simulation analysis, as the authors amply demonstrate, allows great flexibility in analyzing a broad range of scenarios.

The exposition in this report left quite a bit to be desired. Much of the text is a sequential statement of the results of the simulation analysis, in which the authors list somewhat repetitively the outcomes of the various studies as they apply to the different customer groups or utilities. Of course, how detailed or technical the discussion ought to be depends upon the audience to which it is directed. Nonetheless, we feel that in general the discussion would benefit considerably from some broader more general discussion of, for

example, the averages of some of the effects. Thus, the authors might have observed at some point that "for the most part the effects of such and such a policy, e.g. seasonal rates, on residential customers seems to be . . ." Such discussion would enable the reader of the report to form overall views on the various policies and issues analyzed in the study.

There were several areas in which rather substantial methodological problems arose. These were found primarily in the section on marginal cost pricing. Of course, this was to be expected because it is in this setting that the least real world evidence is available. Nonetheless, the following are points which we believe deserve further emphasis.

1. There is a major problem with the assumptions about the price behavior of decontrolled natural gas vis a vis the price of oil. The assumption that the price of natural gas will float to the level of the price of imported oil is a crucial one in this section on marginal cost. This assumption deserves very close scrutiny.
2. On the demand side of the model, only one rate form is analyzed, inverted rates. There are numerous of other possibilities, such as lump sum

adjustments, manipulation of the customer charge, and so on. We do note that information on elasticities is very important here and ought to be used at length.

As the authors note, the only really accurate model of the gas utility is the utility itself. The simulation analysis is necessarily limited in the scenarios which can be considered and in the specific assumptions which can be built in. The assumptions necessary to perform such an analysis are clearly not appropriate to any specific utility. But, it is clearly possible to analyze specific utilities using simulation analysis.

This suggests that it is not too early for State Commissions, perhaps with the aid of the Federal government, to require similar analysis for the gas utilities within their respective states. A precedent has already been set in New York State. The New York State Public Service Commission has already required all gas utilities to perform an analysis of marginal cost pricing for their system in each rate case. The Brooklyn Union Gas Company has presented such a study to the Commission in Case 27631. The ERA/DOE study suggests to the New York State Department of Law that a similar analysis for other utilities in other states would be very valuable.

VI

Agenda for Future Research

If the Congress, DOE and the state utility commissions want to seriously consider the implementation of marginal cost rates for natural gas, they should first determine the answer to a number of important questions. Answering these questions will involve further research, which should bring together government and academic economists, engineers, state public utility regulators, and representatives of the natural gas industry, including distribution, pipeline, and production officials. Among the questions that should be answered before state commissions impose marginal cost based rates are:

1. How is marginal cost to be estimated?

Whereas the estimation of average embedded costs has a long history, relatively little attention has been paid to the estimation of marginal costs. Among the problems that should be faced are:
Do we want to base rates on long-run marginal costs, short-run marginal costs, or some compromise between the two? Should the state commissions require their distribution companies to look only to their own marginal costs (taking the rates they face from their pipeline suppliers as representative of true costs), or should they attempt to determine the "global" marginal costs? Should the state commissions require the utilities to consider

external costs, i.e. social costs that are not reflected in private cost calculations, such as the risk of an LNG explosion in a crowded harbor?

2. If marginal cost based rates raise revenues in excess of the utility's revenue requirement, what should be done with the excess? Should the utilities use this "excess revenue" to pursue offshore gas supplies, to build SNG facilities, to build coal gassification plants? Or should these "excess revenues" be refunded to the customers, so that, on average, they are not hurt by marginal cost based rates?
3. Assuming that the commissions decide to return the "excess revenues" to customers, how should this be done? This question itself contains several parts. First: what are the alternative methods available for returning these revenues? Certainly a listing of these methods will include inverted rates, inverse elasticity based rate designs, rebates, and reductions in the customer charge. After the possibilities are enumerated, researchers should proceed to determine the benefits and costs of each of the alternatives.

One criterion for evaluation is the effect of the alternative on conservation incentives.

For example, will the reduction in the customer charge reduce the incentive to conserve because some customers will look only at their total bill (which will be unchanged, on average) and not at their marginal rate?

4. The administrative difficulty and associated costs of the alternatives will certainly differ. It would be useful to get the utilities' involvement in determining which of the alternative methods for returning "excess revenues" to customers is most costly, and which is least costly. Some of the methods may be totally infeasible, and some may be feasible but excessively costly.
5. What are the equity or distributive effects of the different refund alternatives? This question and most of the others listed above require a detailed estimation of the demand for natural gas by final users. This estimation must be carried out in different parts of the country: one cross sectional study is not sufficient. Knowledge of demand elasticity is important, for example, in

establishing the equity effects of inverse elasticity based rate designs. Obviously, before we can implement inverse elasticity based rate designs, we must have a good idea what the demand elasticity is for the different service classes.

6. What will happen if some states institute marginal cost pricing for natural gas, while other states do not? Will the rates under marginal cost pricing be so different from average cost based rates that some firms will choose to move from marginal cost to average cost rate design states? If so, how many firms will move? Is there any social benefit to the moves? What will be the socio-economic impact of these moves? Is there any way to prevent a problem of this sort through legal action by the Congress?
7. How much conservation will actually be achieved by marginal cost pricing that would not be achieved by average cost pricing? What are the net benefits of this additional conservation: alternatively, what are the net national economic benefits from the improved efficiency adjustments that would accompany marginal cost pricing? These net benefits should, of course, include a consideration of all costs caused by a shift from average cost to marginal cost pricing.

8. Finally, is the shift from average cost to marginal cost pricing worth it? That is, are the net national economic benefits of such a shift positive?

APPENDIX

COMMENTS ON
ICF NATURAL GAS RATE DESIGNS STUDY -
INTERIM REPORT NO. 5

Submitted by:

The New York State
Department of Law
(under contract to the
Department of Energy)
Energy and Utilities Section
Two World Trade Center
New York, New York 10047

Prepared by:

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January 31, 1980

1. The comments contained herein relate primarily to methodology. The comments do not go in detail into issues of appropriateness of the assumed parameters. We would suggest that the American Gas Association be asked to provide expertise on whether or not the assumed parameters and rate designs are realistic. With the exception of marginal cost pricing and lifeline rates, we feel that the study does analyze all reasonable rate designs. The descriptions of the distributors is fairly terse, so it is difficult to know whether or not they are reasonable or appropriate. With respect to DOE questions numbers 1, 2, and 4, (memo. from S. Skjei, 1/11/80, U.S.D.O.E.), as suggested above, we feel that the American Gas Association provides a more appropriate source for information. DOE question number 3 (Ibid.) is discussed to some extent below.

2. Page II-7, Item B

The description refers to "The natural growth of demand". This is rather imprecise term: the authors should specify what factors affect this "natural growth of demand". Presumably these factors include growth in population, growth in real income, and other items. What parameters were assumed for these growth rates? Were there sensitivity analyses on these rates? Do the parameters vary from company to company (A-B-C)?

3. The following comments relate to Appendix B - The Demand Model:

- A. In numerous places a "conservation effect", as distinct from a purely price induced elasticity effect, is discussed. Yet in the demand model this conservation effect is absent in formal terms. The authors of the study should reconcile this discrepancy.
- B. A number of significant demographic trends probably affect the forecast of the number of customers in the demand model. These effects are probably most important in the determination of the variable labelled TNU on page B-3. They may well be included in the DRI estimate of the growth parameter. If not, the authors should discuss how they (Demographic Trends) would affect this parameter (TNU) and perhaps consider them; if so the authors should discuss how these demographic trends are reflected in that growth parameter.
- C. There is no income effect in any of the demand equations which define use per customer. Note especially page B-5. There may be an important income effect in gas usage, for example, in the purchase of appliances, gas stoves, etc. The authors might address this question.

- D. The description of the residential demand model on page B-5 states that the long run effect would be due to the installation of heat pumps etc. However, the parameters of that model were estimated over a period during which the use of devices such as heat pumps was quite limited. Therefore, it is not unlikely that the long run elasticity in the demand model are underestimates of the true effect which we could expect to observe.
- E. The demand model is probably considerably more detailed than necessary. Throughout its construction it is assumed that various uses by customers occur in particular rate blocks, for example heating usage takes place in block one, non-heating usage, in block two given heating usage, and so on. However, the fact is that customers do not use gas in this fashion at all. The daily cycle of gas use includes all functions so that, for example, in the early part of the month, some gas in rate block one is used for heating and some is used for cooking. Given this, the model could be considerably simpler than the one the authors have used. It probably makes sense to have separate demand elasticity effects for heating customers and for non-heating customers. However, within these categories it

may not be necessary to have several elasticities within each rate block. A simpler model could probably be devised based upon the work of Lester Taylor in his Bell Journal survey in 1976 or 1977.

4. Table II.4, on Page II-9 describes growth in the number of interruptible customers. Prior to this point, the study has not described the terms under which these customers can be interrupted. What is being assumed about the terms of the contract for these interruptible customers? Under what conditions, and with what lead time can they be interrupted?
5. On Page II-8 it is noted that "growth and residential customers is affected slightly by differences among these rate forms, because of the small difference in average rate." This sentence seems to indicate that the authors have assumed that customers usage patterns are affected only by average rates and not by marginal rates. That is, customers are sensitive to their total bills and not to the marginal rate embodied in the total bill. Do the authors have empirical justification for this assumption? Much of economic theory would run contrary to the assumption that customers are sensitive to average prices and not to marginal prices.

6. The finding - on page II-14 - that "Industrial conservation shows little variation by size" is surprising. The authors should provide a discussion of the reasons why the amount of industrial conservation undertaken is not sensitive to price. Furthermore, the sentence in the middle of II-14 about the effect of declining block rates provides a unique opportunity for an observation about the perverse effects of declining block rates. The large customer obviously has more potential conservation opportunities, and since declining block rates reduce the number of those opportunities that the large industrial customer will invest in, declining block rates obviously have a perverse effect on conservation. This is an obvious point, and one that's been stated before, but the fact that the ICF model confirms the observation that a declining block structure is the worst of all worlds for efficiency purposes should be emphasized strongly.
7. The authors should discuss the reasons, in Table II-10, that the Northeast Utilities' residential customers bear a much higher proportion of the total distribution cost than do the residential customers of utilities B and C.

8. The first sentence in the section "Typical Residential Bill" on page II-20 is a peculiar one. The authors should be more specific: for example, "rising prices" of what? It is difficult to understand what they mean.
9. The discussion of volumetric rates on the first page of Chapter III is too brief. Although it is not clear, it appears that the authors have not allowed a customer charge (differing between classes) to be applied. This is an alternative form of volumetric rates - i.e. volumetric rates with a customer charge - which could have been used.
10. A more dramatic inverted block rate structure could have been used. In particular, the first block rate could have been structured similar to a lifeline rate. We are not advocating this alternative, but merely suggesting that the authors state clearly that their inverted block rate structure is not the oft-discussed lifeline rate.
11. The observation at the bottom of page III-9 is an interesting one. We had expected that inverted rates would lead to fuel switching that would dwarf any other effect they might have. But the model predicts that the fuel switching would be just about counteracted by the increased service to interruptible customers. How much confidence do the authors have in these results?

12. On the first page of Chapter IV, the authors should be clear about the use and implication of a "single cap" at the wholesale price of residual fuel oil. Exactly what does this mean? Are there alternative assumptions that are equally reasonable, and if so, why weren't they used? If the reader does not understand the use of this cap, the chapter itself is unintelligible. A discussion of the nature of "incremental" pricing would also be useful.
13. The major observation at the bottom of this first page of Chapter V is not clear. Perhaps it's because we did not understand the point in the body of the report, but this conclusion does not make sense.
14. The sentence on page V-2, that begins "by 1990, under..." may have a word missing. It is not clear which customers are referred to in the last four words.
15. We should also add, as a major observation, the fact that declining block rate structures lead to much less conservation by the customers who matter most (large volume users) than do any of the other rate structures.

16. The authors could discuss Table V-1 in more detail. In particular, except for the fact that the share of distribution born by residential and typical residential bills only score M, inverted rates seem to be preferred. Perhaps the authors could select two or three of the cases and compare them, i.e. flat rates with customer charge versus inverted rates.
17. On page V-4, the authors discuss price response changes to be made in the next phase. We would suggest varying the elasticity of demand as the price of gas approaches the BTU equivalent price of fuel oil. Actually, looking at Table I on page A-10, it appears that the fact that the elasticity varies by rate block may actually accomplish the variation we would like to see.
18. At the bottom of page A-11, the authors describe their "switchpoints". We would be interested to know just what the price premiums, above the price of the alternative fuels, were. Furthermore, what justification do the authors have for choosing these price premiums? In the description on page A-12 it appears that switching takes place immediately - that is, at the instant that the gas price passes the switchpoint. Is it possible to allow for gradual switching?

19. The cost allocation factors for plant and expenses are not clear. In Table IV, it is noted that three items - rate base, gross plant, and revenue are allocated "based on previous allocations". What are these allocations? Are the allocations in the table above these three items? It is not at all clear what is meant by "previous allocations". This is an important issue, and deserves more detailed treatment.

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April 16, 1980

Mr. Stephen S. Skjei
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Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
2000 M Street, N.W. Room 2313
Washington, D. C. 20036

Re: ERA-R-79-22: Gas Utility Rate Design Study

Dear Mr. Skjei:

The Interstate Natural Gas Association of America (INGAA) respectfully submits the following pursuant to your request for comments relative to the preliminary discussion draft of the gas rate design study dated March 21, 1980. The person to contact in regard to these comments is Arthur G. Gillum, Director of Finance and Accounting, Interstate Natural Gas Association of America, Suite 601, 1660 L Street, N.W., Washington, D.C. 20036, telephone (202) 293-5770.

INGAA is a nonprofit trade association representing virtually all of the major natural gas transmission companies operating in interstate commerce in the United States. The interstate natural gas transmission industry has been subject to extensive regulations for a number of years and under current law INGAA's member companies are subject to rules and regulations of the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) as well as other departments and agencies of the Federal Government. INGAA has a vital interest in the study authorized by the Public Utility Regulatory Policies Act (PURPA).

Unfortunately, the final conclusions of the rate structures assessed by the study are not included in the draft, however, it is apparent that the primary thrust of the report will be to endorse the use of marginal cost based rates to best achieve the objectives of PURPA. INGAA wishes to express its opposition to the advancement of such rate theory to Congress without full disclosure regarding the severe and unresolved problems of its practical application in utility ratemaking. INGAA further expresses its concern relative to the inequitable expounding of the attributes of untried marginal cost based rates and the alleged deficiencies of existing or average cost rates.

INGAA contends that the ERA has an obligation to the public interest to disclose and fully address the following relevant issues before it can justifiably endorse marginal cost based rates to Congress within the context of the PURPA mandate.

- The uncertainties associated in the transition from a simulation of an untried rate design to a real world situation where demand/supply responses are not programmable.
- The theoretical problems associated with marginal cost based rates which must be resolved in practical terms, e.g. the length of the periods over which costs are to be considered, the size of the unit of production to be given a marginal value and the method of allocation of common costs to the various customer classifications.
- The limitations imposed by "cost of service" regulation in which overall revenues must be held to overall costs. Marginal cost based rates can only be instituted within this framework. Its method of implementation will determine its economic consequences which, though uncertain, could likely deviate from PURPA objectives.
- The impact, if any, that end-user rate forms will have on the efficiency of the pipeline purchase decisions at the wellhead.
- The impairment of the revenue collections process presently designed to recoup allowable costs without need for retroactive adjustments, refunds, etc.

INGAA concedes that the rate design study is a monumental task, however, simplistic solutions to complex problems will aggravate rather than enhance the most efficient use of natural gas. Economic theory must be measured in terms of practical application and Congress must be so advised to properly act in the best interests of the public.

Appreciation is expressed for the opportunity to comment during the development stages of the gas rate design study and it is hoped that the suggested modifications will be given your utmost consideration. INGAA looks forward to continued participation in the next phase as legislative recommendations and proposals are developed for submittal to Congress in November.

Sincerely,

Arthur G. Gillum
Director, Finance and Accounting

AGG/sms

STATE OF NEW YORK DEPARTMENT OF PUBLIC SERVICE

THE GOVERNOR NELSON A. ROCKEFELLER
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Secretary

April 17, 1980

792228A

Mr. Stephen S. Skjei
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, DC 20461

Dear Mr. Skjei:

Commissioner Richard Bower and I reviewed the draft copy of the Gas Rate Design Study which you sent me. I conveyed many of our comments to Janet Grimes of your staff on April 14 by phone. This letter is an elaboration of those comments. I trust that you understand that the views expressed below are the personal views of Commissioner Bower and myself, and do not necessarily represent the official views of the New York State Commission or Staff.

Most of your conclusions are correct but you have unfortunately stopped short of making the important policy recommendations which follow from your analysis. Both Commissioner Bower and I are concerned that the way in which some of your conclusions are stated, coupled with the lack of policy recommendations, will tend to encourage some readers to draw the wrong inferences from your work. For example, in Chapter 5 after discussing rates based on the marginal cost of gas to a distributor, you observe that such rates can aggravate the problems of over-consumption and uneconomic purchases of high cost gas. The implication seems to be that if New York State pursues a policy of basing rates on the marginal cost of gas to distributors, it is pursuing a bad pricing policy. Our view is, of course, that such a pricing policy may be the best available to New York State. The reason it has undesirable consequences from a national perspective is because pricing at the interstate level is done incorrectly. It would be better to state that the

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practice of averaging gas costs at the interstate pipeline level aggravates the problems of over-consumption and uneconomic purchases of high cost gas particularly when a state decides to adopt marginal cost based rates based upon the costs its distributors see. You should then state that the proper remedy for this problem is to make pricing at the national level more rational, not to prohibit states from pursuing their own self-interest by adopting what is, from their perspective, the most sensible pricing practices.

Although we encourage you to expand the report to include recommendations, we also believe you should shorten the report by limiting yourself to an analysis of the major issues. For example, while the historical perspective, Chapter 2, is nicely presented, it seems to us much longer than what is needed in this paper. Tables, such as 7 and 8 in Chapter 4, take up a lot of space but do not seem crucial to understanding the key issues.

Because this paper deals with gas rate design issues it is important to distinguish rate design from revenue allocations. There should be some discussion of the difference between allocating revenue responsibility to customers, or classes of customers, and rate design. It has certainly been common practice in the past for regulators to separate issues of revenue responsibility from rates. As presented here (Pages 3 and 8 of Chapter 4) rates are used to determine revenue responsibility.

For my own convenience, I am now going to list comments on a page-by-page basis. The order in which they appear has nothing to do with the importance I attach to them.

1. You should have a table of contents and an executive summary. The entire discussion on Page 31 of Chapter 5 is of major importance and I suggest you move it to the front of the report with a brief introduction which explains that of all the rates examined, those based on economic costs appear to be the most desirable.

2. In Chapter 1 at the bottom of Page 2 and the top of Page 3 there is some discussion of declining block rates. You should recognize that not all of a company's costs are gas costs. At one time, declining block rates may have made sense because they covered the full marginal cost of gas

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and they insured a larger contribution to common costs from the least elastic users. Thus, contrary to what is suggested in your draft, whether declining block rates are justified or not does not depend on whether a company's cost of gas drops as the quantity it sells increases.

3. Chapter 2.

A. On Page 8 you suggest that there will be little conservation associated with aggregate feedstock demand. There have been some changes, notably in the chemical industry, which have significantly increased the product yield per unit of feedstock. Presumably, one of the motivating forces for looking for such process changes is the price of the feedstock.

B. On Page 13 you note that all methods of meeting peak winter demand incur high costs except interruption of service. In a properly operated system, the costs of meeting additional load at the margin by using any of the listed techniques might be about the same. (The marginal costs will tend to be equal.)

C. On Page 18 you assert that pipelines that can roll-in the costs of gas they purchase will bid up prices for new gas to undesirably high levels. Normally, it is not considered wise to pay more for a product than you plan to sell it for. If you expect the interstate pipelines to engage in such strange behavior and you believe such behavior is a pernicious result of Federal regulation, you should say so. You could note that gas adjustment clauses can encourage this otherwise irrational and undesirable behavior. This same issue comes up again on Page 20 and Pages 4 and 6 of Chapter 3.

D. On Page 20 and 21 you should probably note that the average cost of transportation to distributors varies greatly across the country.

E. On Page 22 in the first four paragraphs, you incorrectly state that if all customers had the same ratio of peak demand to average, the allocation of cost between demand and commodity would not matter. For this to be so you would also have to assume that all usage is completely insensitive to price level, otherwise you will have inefficiencies from either under or over pricing of resources.

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F. What is meant by the last sentence on Page 27? Are you suggesting that such a price structure improperly encourages added consumption? If so, then you also need to show that the price charged is below marginal cost. Since that doesn't seem to be your claim at this point, I suggest you change that sentence to simply read "This price structure may properly encourage additional consumption as long as the block rates are at or above the marginal cost of gas."

4. Chapter 3.

A. On Page 4 you should emphasize the absurdity of Federal pricing policies which make it attractive for interstate pipelines to pay more for gas than it can be sold for. This same issue is also discussed on Page 6 and Pages 18 and 20 of Chapter 2. Perhaps you should discuss it just once.

B. On Page 7, in the last paragraph, you may also want to include an estimate of the economic loss due to the inefficient use of gas by those who did receive it (because it was priced below its opportunity cost).

C. On Page 9, in the third paragraph, you discuss how incremental pricing to industrial customers may reduce the price charged to other utility customers. You should note that it would not be desirable to push prices to other customers below marginal cost. On the other hand, incremental pricing may simply tend to bring the rates charged industrial customers closer to those charged other utility customers. From the point of view of economic efficiency that may be desirable.

D. I don't think most of the discussion on Pages 11 and 12 under "Prices of Gas" is needed to explain gas rate design issues.

5. Chapter 4.

A. On Page 2 in the first paragraph, it is observed that accounting cost based rates are tied to average, historic costs. An equally important characteristic is that all costs, including common costs, are allocated to some group of customers as if each of the costs were directly caused by some particular group of customers. In fact, a large number of costs, called common costs, are by their very nature not caused by any particular customer or group of customers. Thus, not only are accounting cost based rates based on average costs, but they are based on an allocation that is almost invariably highly arbitrary.

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B. On Page 3, rates are discussed as if they alone determine revenue responsibility. In fact, decisions about revenue responsibility can and have been made independently of decisions concerning the form that rates should take.

C. On Page 5, the last sentence in the second paragraph is confusing. If the rate structure is unchanged, and the rates charged in all blocks are raised the same percentage, then what kind of demand equation gives you a different response for a different basic structure? Your use of the word "incentives" in the last sentence seems particularly odd and suggests to me that you are talking about a static situation and are not examining the expected changes over time.

D. The prices and quantities in Tables 1 and 2 seem inconsistent. For example, under "Flat with Customer Charge", a price increase to industrial customers leads to a dramatic reduction in usage. Under the volumetric rates, a substantial price increase leads to a substantial increase in quantity used per customer. This doesn't seem to make any sense.

E. On Page 8 in the last paragraph, what you say is true because you have tied revenue responsibility to rates. But as I noted earlier, revenue responsibility for each class of customers can be set before the rates for each class are determined.

F. The average rates shown in Table 3 vary across rate types. Is this because revenue responsibility for the residential class is different for each of the basic rate structures examined and is this because you have considered the price responsiveness of the class?

G. On Page 9 you give an example of how to use the inverse elasticity rule. You may wish to identify it as such.

H. On Page 10 in the last paragraph, you seem to confuse characteristics of the rates under static conditions with how consumers will be affected by the different rates over time.

I. On Page 14, in the first full paragraph, you state that commercial customers will conserve but not to the extent that residential customers will conserve. Is this a direct result of assumptions built into the model concerning price elasticity? If so, then you are not stating a result but merely an assumption.

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J. Should the average rates shown in Table 10 match those shown in Table 7? For example, in Table 10, under 1990 Base, the average Flat, Declining Block and Volumetric rates are given as 4.50, 4.49 and 4.56. In Table 7, the same average rates are given as 4.60, 4.49 and 4.56. In Table 10 why does the average rate shown for Declining Block change so much between Base and High for 1980?

K. On Page 16, the middle paragraph seems to suggest that the load factor of industrial customers is much worse than the load factor of residential customers. I don't think this is what you intended.

L. Tables 11 and 12 seem of minor importance. They can be replaced by a sentence which simply says that the form of the rate structure alters the contribution by different classes to non-gas expenses. You could follow that with an example.

M. The discussion of interruptible customers on Pages 21 and 22 should point out that if rates were set to reflect the fact that the marginal cost of gas on peak days is quite high, many interruptible customers would voluntarily choose to leave the system and use an alternative fuel. They would decide for themselves. As discussed here it sounds as if the only issue is how the gas company will manage its supply of gas without using prices. In addition, I believe your cost estimate of 21¢/dth underestimates, by a factor of 2 or 3, the marginal cost of storing gas except in areas where there is a substantial surplus of storage capacity.

N. Pages 23 and 24 were missing from our draft copy.

O. In Table 19 on Page 30 did you assume that any excess revenue from incremental pricing would flow back to the pipeline, or did you assume that states would set rates, as they have, in a way to keep such revenue within the state?

P. The numbers in Table 20 on Page 32 seem to be at odds, in some instances, with the numbers in Table 2 in Chapter 4. For example, for a high cost utility, why is the volume of sales to firm customers under the Volumetric rate in Table 20 for 1990 less than sales under the Flat type of rate, whereas, on the basis of numbers in Table 2, it would appear that just the opposite would be the case. In addition, the change in average prices shown in Table 1 of Chapter 4 suggests that there might be a larger increase in consumption between 1980 and 1990 under the volumetric rate than under the other two rates.

Mr. Stephen S. Skjei

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Q. The last sentence in the first paragraph on Page 33 is misleading. Take it out.

R. On Page 33 and 34 you discuss the improvement in load factor that should accompany a shift to industrial customers. The current end-use priority system that Federal regulatory agencies have looked on with such favor in the past provides a strong incentive for distribution companies to attach "high priority" loads. Thus the scenario you describe here seems to have little relevance for many distribution companies in New York State.

S. The last statement on Page 36 concerning stability of rates is only true if the price being charged is above the marginal cost of gas.

T. On Page 37 you need to qualify your statements about the desirability of stable earnings. As you observe, the cost of equity capital may rise if a "less stable" rate structure is used. On the other hand it may not.

U. On Page 37, under your discussion of shortages, you should clarify what you mean when you say in the third sentence that distributors cannot purchase as much gas as they can sell. From what follows it becomes clear that what you mean is that distributors cannot purchase as much gas at regular pipeline rates as they could sell at prices that are only slightly above those rates, and that other supplies of gas available to the distributor are too costly to be of interest to the distributor.

V. I am puzzled by your discussion of interruptible load at the bottom of Page 38 and the top of Page 39. Why would what you describe here happen? Is it the result of price assumptions or regulatory policy assumptions? Do interruptible customers get priced off the system because your accounting cost based rates did not reflect differences in peak and off-peak costs?

6. Chapter 5.

A. On Page 1, in your introduction to marginal cost based rates, you suggest that rates have been set historically on the basis of accounting costs. Some reasonable people believe they were actually set on the basis of marginal costs, or value of service, and only later justified on the basis of fully allocated cost of service studies.

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B. On Page 4 you suggest that one way to obtain rates that are based on the real resource costs to the Nation is for state regulatory commissions to try to guess what that resource cost is and then to base rates charged by distribution companies under their jurisdiction on that cost estimate. Why would it ever be in a state's best interest to do this? It seems to me your lead-off discussion on how to achieve such economically efficient rates should focus on the role that Federal agencies should play, rather than suggest that it somehow might be proper for states to adopt questionable pricing rules in an effort to compensate for deficiencies at the Federal level.

C. On Page 6, in the second full paragraph, what do you mean by "and might affect the extent to which gas displaced oil"? If the marginal cost equals the opportunity cost and all the gas that is available at a price below the opportunity cost is being marketed, then are you suggesting that not enough oil is being displaced? If so, why?

D. Your last sentence on Page 6 does not appear to make sense. Pipelines should not rationally choose to forego a sale at a price equal to or above their marginal cost. Pipelines might have to extract a larger portion of their fixed costs from the less elastic customers if their marginal costs are below their average costs.

E. On Page 10, in the first paragraph, you say that changing the basis for setting rates from accounting to economic costs does not alter the rate increases that all customers will experience between 1980 and 1990. This seems like an odd assertion. Won't a change to economic cost based rates change the quantity consumed and hence mean that different supplies are acquired by pipelines? For example, if consumption is 25% less under economic cost based rates, as suggested in paragraph 2, then won't the pipelines avoid the cost of some of the more expensive supplies of gas? Have you assumed that marginal cost equals average cost for a very wide range of supplies?

F. On Page 11, in the first full paragraph, you note that when the real resource cost is less than the average cost, rates based on resource cost will lead to greater consumption. You should note that this is desirable. You might also note that such rates will lead to lower average costs as well.

Mr. Stephen S. Skjei

April 17, 1980

G. In the second full paragraph on Page 11, you suggest that the price an intrastate distributor pays for gas may be above its real resource cost. How can this be if interstate pipelines are required to market gas according to their marginal costs? The real resource cost, the marginal cost to pipelines, and the opportunity cost are really all the same thing. Thus, what you assert in the last sentence of this paragraph just can't be true. If pipelines try to charge more than the real resource cost of gas, they won't sell it because customers will choose cheaper alternatives. It is worth noting that if a shift is made from average cost pricing to marginal cost pricing there will be a shift in purchases from companies with low average costs to companies with high average costs. This is as it should be because it adds to allocational efficiency.

H. On Page 14, in the first paragraph, you do not mention the fact that the real resource cost of gas is generally higher at times of peak demand. Therefore, if rates are really based on resource cost, residential customers with poor seasonal load factors may find that their average price has increased. Is your assertion that the average price will drop based upon a consideration of how the real resource cost of gas varies by time of usage?

I. In the last paragraph on Page 14, a reference is made to a lifeline rate. You have not used a lifeline rate. You have used a rate which is based, in part, on the price elasticity of some users.

J. On Page 15, in the second paragraph, you state that economic cost based rates are higher than accounting cost based flat rates, but that the residential contribution to overhead costs are lower under economic cost based rates. Why, if residential customers are paying higher rates, do you conclude that they are making a smaller contribution toward overhead costs, particularly when you seem to have implied earlier that you have assumed that residential customers are less price elastic than industrial customers? I think you may have gotten yourself into this seeming contradiction by tying revenue allocation to rates.

K. Your last sentence on Page 18 explains why the allocation procedure you describe two sentences earlier is not very good.

L. At the bottom of Page 22, you once again refer to reductions in sales to interruptible customers. What is the basis for this? (See Chapter 4, comment V above.)

Mr. Stephen S. Skjei

April 17, 1980

M. On Page 23, in the last paragraph, can we safely assume that the marginal cost of gas at all times during the year is above the price interruptible customers would pay for an alternate fuel? It also appears that, for the high cost utility, you are dealing with either a smaller price change or less elastic customers because you get a smaller percentage shift away from gas when you change from accounting to economic cost based rates.

N. On Page 25, you seem to be setting up a straw man. There are other supplies of gas then gas priced at the oil equivalent price of \$15/bbl. What you should say is that if supplies are marketed at a price based upon accounting costs, there may be shortages.

O. The last statement on Page 27 does not seem correct. Why would it not be to the advantage of the high cost utility to serve interruptible customers during off-peak periods? Have you assumed that the real resource cost of gas at all times of the year is above the alternate fuel price faced by interruptibles?

P. You might wish to emphasize on Page 28 that one of the perverse effects of gas adjustment clauses is that they encourage the purchase of gas by distributors for more than its opportunity cost.

Q. On Page 31, your last point is that, under economic cost based rates, gas is allocated better when supplies are limited. Supplies are always limited. In addition, while it is important that such rates ensure that the supplies of gas are allocated to those customers who place the highest value on it, it is also important that under such rates the level of usage by customers who receive the gas will be more in line with the levels of usage that are economically efficient. That is, the gas will be used more efficiently by those who get it.

7. In looking at the tables at the end of the report, I see nothing which indicates that you examined marginal costs as a function of peak usage. Does this mean the marginal costs shown are average seasonal marginal costs? If you have been unable to include an analysis of how marginal costs vary by time of usage, then I encourage you to state that in the main body of the report.

8. The "Impact Matrix" tables are of little value.

Mr. Stephen S. Skjei

April 17, 1980

Both Commissioner Bower and I appreciate the opportunity to review the draft. I hope our comments are helpful.

Sincerely,

A handwritten signature in cursive script, appearing to read "Joel Brainard", with a long horizontal flourish extending to the right.

Joel Brainard
Policy Analyst
Office of Research

cc: Richard Bower

W. J. Jefferson
Executive Director of
Rates and Regulation

General Offices: 212 West Michigan Avenue, Jackson, Michigan 49201 • Area Code 517 788-1230

April 16, 1980

792229A

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

Gas Utility)
Rate Design Study)

Docket No ERA R-79-22

Pursuant to the MEMORANDUM FOR DISTRIBUTION dated March 21, 1980 from Mr Stephen S Skjei, Consumers Power Company (the Company), hereby submits comments on PRELIMINARY DISCUSSION DRAFT COPY OF THE GAS RATE DESIGN STUDY (Draft Study). Consumers Power Company is a member of the United Distribution Company (UDC) group, and supports the comments filed in its behalf by UDC. These comments are intended to supplement those filed by UDC. The major concern of Consumers Power Company is the overall tone of the Draft Study. A study of this magnitude and potential impact should be highly objective in reporting facts about the gas utility industry, as well as results from the hypothetical market analyses provided by the model utilized. Instead, the Draft Study is overly subjective. Conclusions are drawn based, in some cases, on assertion not fact. The hypothetical model is not producing actual, demonstrated results, particularly when the output concerns the effects of changes in price on consumption of energy.

The Company is a combination gas and electric utility serving over 1,000,000 gas customers and 1,250,000 electric customers in the lower peninsula of Michigan. The Company has actively performed gas cost of service analyses, gas load analyses, and gas rate design by class of service over the last 15 years.

The concept of marginal costs or economic cost pricing as a basis for retail gas rates cannot be rationalized as the savior for the gas industry by the type of analyses and incomplete or misleading statements appearing in the Draft Study. The use of accounting costs is consistent with the determination of revenue requirement under the present scheme of regulation. At Page 1 of Chapter V, Marginal Cost Based Rates, it is stated that: "In contrast to accounting costs, which reflect the costs of past decisions and actions, marginal costs indicate the costs of current decisions." In a gas rate case presently being prepared by the Company for filing with the Michigan Public Service Commission the test year cost of service for determining revenue requirements will reflect the historical calendar year 1979 data plus forecasted changes in the cost data through December 1981. The Company submits that there is no need to mandate or adopt any alternative form of cost determination. The present system employing an "accounting cost" methodology can be forward-looking in determining revenue requirements. It is extremely misleading for the Draft Study to indicate so categorically to the contrary.

An economic cost basis for rate design can be utilized by either pipeline or distribution companies. At Pages 4 and 5 of Chapter V it is indicated that, with an economic cost pricing approach, there would be a revenue collection problem -- that is, total rate revenues would exceed total costs of gas. Further, it is indicated that one way to resolve the problem of overcollections is to invert the rates. Even if rate inversion could resolve the problem (which we do not concede) it could well create a customer equity problem, lead to customers not receiving appropriate price signals and be counter-productive insofar as encouraging conservation is concerned.

Rate inversion of a pipeline company's rates could lead to a large distribution company purchasing a substantial amount of its gas requirements in the higher priced tailblock, while a small distribution company might purchase all of its gas requirements in the lower priced first block. Both companies might have the same end-use customer mix, the same supply contract terms and equally efficient operations, yet the cost of gas to the smaller sized distribution company could be significantly lower on a cost per unit basis. The small distribution company, as well as the end-use customer of that company would not receive the "appropriate" price signals. Moreover, the small distributor could have a customer mix of essentially low priority end use, while the larger distribution company could have a customer mix of essentially high priority end use. The inverted rate form might not provide a pricing mechanism which gives the end user appropriate price signals, and might not assist in the movement of gas to the most efficient uses. These situations merely serve to illustrate potential inadequacies of such economic cost-based rates. Marginal cost pricing is not a cure-all, and weaknesses and strengths should be pointed out in an objective manner. The real world does not work as smoothly as a hypothetical model.

Rate inversion of distribution company rates can lead to small sized customers receiving inappropriate price signals. For example, on Consumers Power's system around 63,000 (over 90 percent) of the commercial customers have an annual consumption of 200 Mcf or less. These customers account for about 50 percent of the annual commercial usage of gas. An inverted commercial rate would seemingly give inappropriate price signals to a substantial number of customers. In addition, such a rate design would completely ignore the appropriate allocation of significant fixed costs to the small commercial customers. It is not at all clear that conservation would be promoted through an economic cost approach to rate design.

Additionally, we believe that inverted rates would not solve the revenue collection problem, but would rather exacerbate the problem. Gas distribution companies will continue to incur substantial fixed costs in providing service to the ultimate consumer. In order to remain financially viable those fixed costs must be covered by revenues with a reasonable degree of certainty. This being the case, revenue stability is a critical criterion by which any rate design proposed must be evaluated. The discussion of revenue stability in Chapter V of the Draft Study is totally inadequate. It is not at all clear how revenue stability is promoted with economic cost-based rates. With inverted rates, revenue instability is bound to worsen because customers subject to tailblock rates have so great an incentive to conserve, switch fuels or -- if they can do neither -- go out of business. If fixed costs must be recovered through the tailblock, a distribution company is practically guaranteed that it will not receive adequate revenues.

On Page 23 of Chapter V of the Draft Study the first sentence under the heading "E. REVENUE STABILITY" states "Under economic cost rates the total revenue requirements of all three distribution company types will be lower." This statement is confusing - "lower" than what? At any point in time, the total revenue requirement of a utility will be the same no matter what rate design concepts are utilized.

Finally, throughout the discussion of marginal cost-based rates any concept of time frame is totally lacking. Apparently, the customers are supposed to react to marginal cost-based rates instantaneously. Nothing is further from the truth. The installation of conservation measures and fuel switching takes time. The regulatory process involved in implementing and subsequently adjusting such a pricing scheme will be very time-consuming. The Company has experienced regulatory lag exceeding three years in completing its most recent rate proceeding and its current gas rate proceeding is in its 25th month. How often must marginal costs be determined in order to give appropriate price signals? The Draft Study lacks a discussion of these matters.

Page 9 of Chapter III of the Draft Study provides an example of the inconsistent emphasis of the report. At the top of the page it is stated categorically that for gas to be used efficiently, its price must reflect its value to the nation as a substitute for imported oil. Yet, in the third paragraph, lowering the price of gas to customers exempt from NGPA to a point below average system costs (and presumably significantly below the marginal cost of gas supplies) only reduces to some extent their incentives to conserve. Any analyses concerning the effects of price on the demand for a good require the use of elasticity measurements. Price elasticity measurements for the demand for gas service are imprecise estimates. The report should discuss the use of estimates in measuring the effects of price on consumption in the hypothetical market analyses from the model. Moreover, the report should not state the effects of price changes with such certainty.

The Company also believes that the Draft Study would have been more objective if statements based on the results of the hypothetical model had been put in a conditional posture. For example, on Page 5 of Chapter I, lines 5-8, it is stated "these results provide useful insights into what will happen under alternative rate design..." The results merely indicate what could happen with various rate forms.

Consumers Power wishes to thank the Economic Regulatory Administration for the opportunity to submit these comments.

Respectfully submitted,

A handwritten signature in dark ink, appearing to read "W. J. Jefferson", with a long, sweeping horizontal flourish extending to the right.

STATE OF CONNECTICUT

DEPARTMENT OF BUSINESS REGULATION

DIV. OF PUBLIC UTILITY CONTROL

April 11, 1980

792230A

Mr. Stephen S. Skjei
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

Dear Mr. Skjei:

We have no real problem with your Gas Rate Design Study. It is well done. We agree in principle with marginal cost concept, provided methodology can be shaped to meet the needs of each basic region or system. The following comments were inputs from my staff. They are somewhat "knitpicks" but perhaps useful.

a. Major issues not adequately addressed.

1. The model used in assessing the rates is barely mentioned. Without a fairly detailed explanation of the model, particularly the computation of elasticities and validity testing over actual data, the findings and conclusions are unsupported.
2. The report mentions a consultant hired for low-income rates, but no low income discussion is included in the report.
3. The objective of having equity in rates is barely discussed. Of course, since equity in rates is usually construed as each customer paying his fair share of accounting costs, this lack of discussion is not surprising.

c. Inappropriate or misleading discussion.

1. The balancing of revenue requirement against economic cost rates is treated as a much more trivial deviation from theory and equity than it, in fact, is.

- e. Labels should probably be A,B,C since the sets of assumptions have no real world referent anyway.

Sincerely,

Charles T. Caprino

Charles T. Caprino,
Director

Rate Analysis, Statistics and Research
165 Capitol Avenue • Hartford, Connecticut 06115

An Equal Opportunity Employer

CTC:hmd

COLUMBIA GAS DISTRIBUTION COMPANIES

99 NORTH FRONT STREET

COLUMBUS, OHIO 43215

THOMAS E. MORGAN
SECRETARY AND GENERAL COUNSEL

April 11, 1980

792231A

Mr. Stephen S. Skjei
Chief, Regulatory Support and
Analysis Branch
Division of Regulatory Assistance
Office of Utility Systems
Economic Regulatory Administration
United States Department of Energy
Washington, D.C. 20461

Re: Preliminary Discussion Draft Copy of the
Gas Rate Design Study, Docket No. ERA-R-79-22

Dear Mr. Skjei:

By memorandum dated March 21, 1980, under your signature, a copy of the above-referenced document was forwarded to the undersigned. Your files will reflect that I have submitted comments in behalf of the Columbia Gas Distribution Companies (hereinafter, "Columbia"), concerning the fourth, fifth and sixth interim reports; Columbia has also participated in two informal conferences conducted by your office pursuant to Section 306 of PURPA. In the course of each of these past efforts, Columbia has endeavored to plainly state its concerns relating to the lack of justification or support for certain fundamental assumptions underlying the technical support documents.

Columbia takes exception to the "Preliminary Discussion Draft Copy of the Gas Rate Design Study" particularly insofar as it embodies a recommendation favoring so-called marginal cost based rates over accounting cost based rates. There is practically no experience, and certainly none on an industry-wide basis, to support the Draft's premise that the marginal cost based rate model will heighten conservation of gas or offset any imbalance in supply and demand for the foreseeable future. Columbia is disturbed by the apparent lack of consideration given to potentially disastrous consequences of the institution of marginal cost rates before all ramifications have been fully explored.

Columbia calls attention to the fact that numerous important issues have not been adequately addressed in the report, including the following:

1. The institution of marginal cost pricing involves major risks to the public service and to consumer interests. This rate-making concept carries with it the danger of major short falls in revenue and loss of certain classes of customers, with resultant increases in residential rates. More particularly, the Draft Report fails to discuss potential economic dislocations which would result from loss of industrial loads, particularly in the midwest. In this connection, the Draft Report fails to admit, as it clearly should, the absence of any consideration of the factors, other than price, bearing on a consumer decision to switch to an alternate fuel and its impact on usage of the alternate fuel. Such other considerations include decisions to "buy rather than make", or to simply go out of business altogether. In the context of the "buy versus make" decision, Columbia notes reference in the Draft Report to natural gas as a feedstock for making ammonia and, therefore, fertilizers (Chapter 2, page 8). The Report should address the potential for foreign control of these markets, and the implications of such control.

2. The Draft Report does not deal with the problem of overcollection or undercollection of revenues resulting from implementation of economic cost based rates without distorting the intended price signal to the fuel user. Because gas distribution companies are uniformly regulated on a cost of service basis, expected revenues from approved rates must be in balance with test period expenses. It is possible that if some rates are increased to reflect marginal costs, other rates may be reduced by a corresponding amount depending on the treatment of excess revenues. In this connection, the Draft Report fails to indicate how currently used gas cost recovery mechanisms, which tend to average costs, might be changed in a manner consistent with the professed goals of marginal cost based rates.

3. The Draft Report does not consider the interaction of marginal cost based rates with Phase I and Phase II Incremental Pricing mechanisms through 1985. If this failure is the result of DOE's assumption that the study results cannot be implemented prior to that time, then such assumption should be explicitly stated.

4. The Draft Report makes no attempt to quantify the impact of either the Residential Conservation Service Program for existing residential structures, soon to be implemented pursuant to the National Energy Conservation Policy Act of 1978 (NECPA), or the Building Energy Performance Standards currently being promulgated pursuant to the Energy Conservation and Production Act of 1976 (ECPA). Such quantification must be undertaken before any reliable forecast can be made concerning conservation under either accounting cost-based rates or economic cost based rates.

Mr. Stephen S. Skjei

April 11, 1980

5. The Draft Report is silent on the critical area of exploration for and development of non-historic sources of gas, such as coal gasification and waste conversion. If such supplies are to be available after depletion of historic supplies, all reasonable steps must be taken to encourage development now. However, to marginally price these volumes would effectively preclude their continued development, because of their high incremental cost. Because these projects are so highly desirable, the report should explicitly consider the effect of economic cost based rates on them.

6. The Draft Report ignores the fact that present industrial loads were added to distribution companies' systems at much lower marginal costs, resulting in lower overall costs to all classes of customers. The new economic cost concept would ignore this end of the marginal cost spectrum.

In addition to the foregoing important areas which have not been addressed by the Draft Report, Columbia notes the following issues which have been discussed in the preliminary document in a misleading or inappropriate fashion:

1. The study suggests that supply/demand imbalances will be exacerbated by accounting cost based rates and that these imbalances will be eased or eliminated altogether by marginal cost based rates. No support has been advanced for either premise. It would appear that the imbalance springs from wellhead pricing controls, geographical location and varying contractual obligations rather than from accounting cost based rates. The study should note that marginal cost based rates may stimulate rather than reduce the imbalance. The real issue is whether overall end user demand for fossil fuels will be decreased over the next few years if a marginal cost rate philosophy is adopted in place of accounting cost based rates for natural gas. As earlier noted, because of the cost of service philosophy in setting rates, if some service is priced at marginal cost, some service would probably be priced at less than average cost in order to limit revenues in relation to overall cost. It is submitted that any conservation by the user who is subject to the marginal cost based rate will be offset by added requirements of users not similarly affected.

2. It is no answer to suggest, as the Draft Report does, an inverted block schedule with a high tail block designed to provide the desired price "signal" under the economic cost based rate theory. It is erroneous to assume that end users, particularly in the residential class, will be influenced by such a mechanism. Instead, it is more logical that an end user of this class would tend to be influenced by his overall billing. It must also be recognized that the concept of a high tail block pegged at marginal cost is completely at odds with "budget plan" type billing, which spreads and levelizes the end user's bill over the calendar year (a device which is becoming increasingly popular with gas consumers). For these reasons, Columbia submits that the Draft Report should expressly recognize that supposed added conservation as a result of marginal cost based rates is at best highly speculative. Furthermore, the Draft Report should recognize

Mr. Stephen S. Skjei

April 11, 1980

and Congress should be informed of the very real gains being made in conservation due to changes in rate forms and usage by state regulatory commissions in response to local conditions.

3. It is insupportable to suggest, as the Draft Report does, that the replacement of accounting cost based rates by marginal cost based rates will cure supply/demand imbalances. The DOE must recognize and credit the strides in conservation which have already occurred, and which will undoubtedly accelerate in the future in all classes of use under rolled-in or average pricing. It is submitted that the currently unknown results of exploration and development through 1985 will have substantially greater impact on the balance of supply and demand than adoption of a new rate scheme.

Accounting cost based rates are apparently being made a scapegoat to protect the true culprit: wellhead pricing controls, which have been, and continue to be, the real reason for supply/demand imbalance. In Columbia's opinion, wellhead pricing controls and incremental pricing, the latest governmental effort to regulate usage, have been and continue to be ineffective to achieve their stated goals. Indeed, as to incremental pricing the Draft Report concedes that this is the case. For these reasons, decontrol of wellhead pricing seems more likely to achieve the goal of accurate price signals to end users than an elaborate rate design embodying marginal cost principles.

4. The Draft Report makes economic cost based rates appear to achieve the desired goals of conservation and supply/demand balance, despite the economic rule of "second best." Briefly, the rule states that when one of the perfect competition assumptions is violated, fulfillment of the other assumptions is generally not desirable. The rule is applicable here because alternate fuels are not marginally priced. For this reason, reduction in gas usage in the percentages indicated in Chapter V, Table 4, may well be inconsistent with the ideal of reducing use of imported oil by efficiently using other fuels, including natural gas. It is impossible to discern from the Report whether the reduction in gas usage reflected therein pursuant to economic cost based rates is the result of conservation of natural gas, increased usage of other fuels (including imported oil), plant shut downs or a combination of these factors.

5. In Chapter IV, in the discussion on load factors, the comment is made that, "As the cost of gas increases, it would appear that the question of load factor becomes less important." While it is true that higher commodity charges make the existing storage charges a smaller percentage of the gas cost, efficient storage operations operate on a tight balance and any major reduction in load factors would require development of new storage fields most likely resulting in higher overall storage charges. This is not adequately measured in the current model since it does not address costs associated with developing new storage fields. Also, lower load factors mean a higher seasonal based load which exaggerates storage problems during especially cold or warm winters.

Mr. Stephen S. Skjei

April 11, 1980

In closing, Columbia suggests that the DOE consider the following alternative labels for the distribution company types identified in this Draft Report. "High Cost Utilities" should be redesignated "Northeast Utilities", "Moderate Cost Utilities" should be redesignated "Midwest Utilities", "Intrastate Utilities" should be renamed "Gas Producing State Utilities." In this fashion, legislators will more clearly understand the regional discrimination inherent in an economic cost/marginal cost rate design.

Columbia urges the DOE to reconsider the decision to present marginal cost in such a favorable light in its Report. No industry is capable, in a free market society, of recovering the true marginal cost of providing one more unit of its product. Averaging is the norm rather than the exception. Marginal cost pricing of natural gas will not change this norm for competing fuels. Therefore, the price signals which the scheme is intended to provide will be masked. For the reasons set forth herein, far more analysis and review is imperative before any such sweeping endorsement can be made without overwhelming risks to reliable distribution of natural gas.

Very truly yours,

Thomas E. Morgan
General Counsel

ADDRESS ALL COMMUNICATIONS
TO THE COMMISSION
CALIFORNIA STATE BUILDING
SAN FRANCISCO CALIFORNIA 94102
TELEPHONE (415) 857-0507

Public Utilities Commission

STATE OF CALIFORNIA

April 10, 1980

FILE # 792232A

Stephen S. Skjei
Economic Regulatory Administration
Department of Energy
2000 "M" St., NW
Washington, D.C. 20461

Subject: California PUC Staff Comments on Preliminary
Decision Draft of ERA Gas Rate Design Study

Dear Mr. Skjei:

Our comments are necessarily limited by other program priorities and the complexity of the draft report. We have recommended to the NARUC that they provide a summary of their March 10, 1980 Questionnaire on the Status of State Natural Gas Rate Design for inclusion in the report.

The draft has been considerably improved from earlier versions and the format appears reasonable. We assume only one additional chapter on conclusions would be added. A detailed Table of Contents and Index to tables in the next draft would be very helpful.

It is also requested that we and the California utilities have an opportunity to review the study of "a company type reflecting the situation in California..." (III-11) should you decide to include it in the report.

Our comments on the attachment are identified by chapter and page number. Observations relative to the quantitative analysis have not been verified by independent calculation but should be useful in identifying potential problem areas.

Very truly yours,

Walter Cavagnaro
Walter J. Cavagnaro
Policy and Program Development Unit

Attachment

cc: Paul Rodgers, Admin. Dir. and General Counsel, NARUC
Charles A. Zielinski, Chairman, NARUC Ad Hoc Committee on NEA
Leonard Grimes, Jr., Vice-Chairman, NARUC Ad Hoc Committee on NEA
Members NARUC Staff Subcommittee on NEA
Ray Nery, Dir., Natural Gas Div., No. Carolina Utilities Commission
H. E. Shutt, Illinois Commerce Commission
John P. Zekoll, New York Public Service Commission

ATTACHMENT

Comments on ERA Draft of March 1980

Chapter/Page

- Introduction - Recommend more specifics of Section 306 be included. That discussion of wellhead pricing, pipeline pricing, and retail rates be more definitively segregated. Phased deregulation of wellhead pricing, incremental pricing, and recent changes in retail rate regulation should be covered.
- I-2/3 Suggest more specific discussion of state rate practices. Demand for gas influenced by many factors other than declining block rates.
- II-5 More emphasis needed on the limited nature of the study.
- II-13 Hopefully, the Questionnaire will shed more light on "traditional" ratemaking. I don't believe that historically too many states have -- "These expenses are divided up among various classes of customers".
- II-24/26 Cost responsibility overstated?
- II-27 Note that the differences between 1971-1978 are fairly uniform - residential, \$1.41 and interruptible, \$1.39. We believe that this is mainly influenced by uniform ¢/Mcf increases under P.G.A's and other rate increases rather than "cost responsibility" advocated by industrial customers and some utilities. You should be particularly concerned if your cost responsibility calculations include some purchased gas as demand. Some comparison by regions would be appropriate.
- II-28
or in
III Page should be added describing the move by the states to raise retail rates to the federal ceiling in order to eliminate incremental price surcharges. This, and state positions on exemptions from incremental pricing, also covered in questionnaire. Summarize innovative ratemaking initiatives by various states.
- III-7 The question of "all wellhead prices were decontrolled" should not be treated so lightly if you are going to treat it at all.
- III-9 We concur in conservation emphasis; there should be more complete discussion. Consider inverted rates as part of solution. Federal incremental pricing does not thus far show significantly higher prices to industrial customers. Your high cost example shows other effects.

Chapter/Page

- IV-1/4 Suggest NARUC Questionnaire results be substituted or two included and compared.
- 3 Paragraph on pipeline rates is out of place here; should be deleted or integrated into discussion at II-21-22.
- 4 We would appreciate reference to Minnesota decision? Appears to parallel action taken in Montana?
- IV-4/6 Suggest some regional analysis of NARUC Questionnaire to compare to Moderate, High & Intrastate.
- IV-7 thru Tables Much more organized and complete discussion of Tables needed if they all are to be included.
- Table 1 - Examination of \$ changes between 1980-1990 may disclose some problem areas. Relationship between residential and interruptible in intrastate may not follow those state rate practices, etc.
- Table 3 - Customer charges appear non-typical.
- V-4 Like to see some citations of the progressive state commissions referred to.
- V-6 Re full de-control, everybody's problems are mentioned except the consumers.
- V-7 Inverted rate examples should also consider the marginal cost of gas.
- V-15 The average price per residential customer need not always be less under inverted rates nor does it necessarily mean a lower residential contribution to overhead costs. This will greatly depend on the relative costs of gas and oil.

PACIFIC GAS AND ELECTRIC COMPANY

PG&E

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W. M. GALLAVAN

VICE PRESIDENT - RATES AND VALUATION

792233A

April 9, 1980

Dr. Stephen S. Skjei
 Economic Regulatory Administration
 U.S. Department of Energy
 2000 M Street, NW
 Washington, D.C. 20461

Dear Dr. Skjei:

In response to your memorandum of March 21, 1980, Pacific Gas and Electric Company (PGandE) has reviewed the most recent version of the Natural Gas Rate Design Study report. The purpose of this letter is to share with you some of our critical observations about the accuracy of the modeling and the applicability of results to individual utilities, especially California utilities and PGandE. It is PGandE's hope that these comments can be usefully incorporated in ERA's written submission to the Secretary of Energy and the Congress.

Before going to the specific comments on the model and the results, there are two remarks that should be made. First, PGandE believes that it is extremely unfortunate that a full summary and conclusions were not included in this version of the report. It is really difficult to provide comprehensive and meaningful comment on an incomplete work. Moreover, it is PGandE's understanding that there will be no further opportunity to review the report before it is submitted to the Secretary. Throughout the evolution of this study, utilities and state regulators have been active participants in the review and revision process; it is regrettable that these parties have been excluded from this crucial last phase. Second, many of the previously submitted comments have been completely ignored. PGandE does not realistically expect that the ICF model can be completely overhauled to incorporate the changes herein advocated. However, it would not seem unreasonable to include an appendix of comments submitted. The Federal Energy Regulatory Commission (FERC), for example, includes a summary of comments when it publishes a

DR. STEPHEN S. SKJEI:

April 9, 1980

regulation. Similarly, it would be appropriate to include comments when this study is released. In order for the uninformed reader to gain an objective understanding of the results, it would be helpful to be able to review comments of utilities and regulators about the limitations of the analysis.

PGandE continues to be concerned about the potential use of the rate design study. We expect that policymakers may seek to use these study as a basis for specific rate design legislation. The consultant, ICF, Incorporated notes on page 5 that, "The only precise model of a given distribution company is the company itself, its varied customers, and its sources of supply." Because PGandE concurs with this statement, it is our belief that this single model should not be used for policymaking for individual companies. The naturally occurring diversity of customer composition, storage capability and supply costs makes a uniform approach questionable. There are too many differences in gas utility operations to make a generalized model useful for individual company analyses. As noted in the report, the results can only provide "insights;" the quantitative results are not "precise forecasts," nor are they representative of any individual company or region.

From a policymaking point of view, some may find the above caveats disturbing. Policymakers constantly seek analytical tools to aid them in formulating equitable and effective legislation and regulations. However, it must be recognized that generalized computerized simulation models do not always provide all of the needed answers. FERC's experience under Title II of the NGPA has amply demonstrated the complexities of the natural gas industry. The reality is that implementation of national regulation of gas distribution compass is extremely difficult at best; to formulate national rate design initiatives on the basis of an imprecise computer model which does not capture the complexities of the industry or particular companies would be grievous. Nonetheless, the policymaker must have a constructive alternative. To PGandE, that alternative is self-evident: require state regulatory authorities to consider a number of rate designs, using whatever utility-specific models or other analyses they deem as appropriate to measure the impacts. This is obviously in the spirit of the Public Utilities Regulatory Policies Act (PURPA) mandate and appears to be the most reasonable policy to pursue.

Having dispensed with overview comments, it is important to provide you with a list of critical weaknesses PGandE believes exist in the model. They are as follows:

DR. STEPHEN S. SKJEI:

April 9, 1980

1. The supply selection process is done on a year-by-year basis. Such a feature fails to recognize the long-term contractual nature of most gas supply acquisitions. For example, the purchase of gas from a supplier in one year may require a company to take gas from a supplier in subsequent year or pay some charge under "take or pay" provisions. The one year planning horizon also fails to include the possibility of storing natural gas from one year to the next.
2. The model treats the supply optimization processes as separate at the transmission and distribution levels. Many gas utilities (including PGandE) have large transmission systems as well as distribution networks. As a result, the supply optimization process must be performed jointly for the transmission and distribution systems. This is similarly the case for combination electric and gas utilities; the optimal operating configuration of gas operations is related directly to electric operations.
3. The demand module does not allow for the influence of the level of economic activity on gas demand in the commercial and non-heating residential sectors. In addition, the price of electricity is omitted from equations determining commercial gas use per customer.
4. The price of imported gas is modeled so as not to exceed the price of residual fuel.
5. The economic cost rate analysis in Chapter V fails to recognize that in the event of wellhead decontrol, pipelines may net back (i.e., discount) the price so that it does not exceed the cost of alternate fuel.

As noted above, PGandE does not believe the model applies to individual utilities. In particular, the model is largely inapplicable to California utilities for the following reasons:

1. The price elasticities of gas demand may not be valid for California. One reason is that much of the data used to estimate the demand module came from the northeastern part of the U.S. The composition of the industrial sector in California is quite different from other parts of the country, thus biasing industrial demand elasticity estimates. DOE's residential gas demand elasticities may not be applicable either. California's mild climate means that customers spend a smaller portion of disposable income on heating than customers elsewhere in the U.S. This may result in a lower price elasticity for California customers than used in the model. In addition, the de facto prohibition on the installation of electric resistance heaters precludes interfuel substitution that is available to residential customers in other regions. Finally, extensive

DR. STEPHEN S. SKJEI:

April 9, 1980

conservation programs mandated in California may cause the model overstate price-induced conservation.

2. None of the categories of gas distribution companies fits PGandE. It is unfortunate that the case of a high import distributor has not yet been analyzed. (PGandE imported 45.5 percent of its gas from Canada in 1979.)
3. The rate structures explored in the report (accounting-based, declining block, flat) are not used universally. In California, industrial customers face incremental pricing for gas, based on the cost of residual or distillate fuel oil (i.e., parity pricing). Residential customers face increasing block rates which begin with a lifeline block up to a certain consumption level with dramatically higher unit prices for consumption above the lifeline level. Thus, California utilities have adopted certain aspects of economic cost structures already.

It is PGandE's hope that the comments contained herein will be helpful as ERA prepares to submit this report to the Secretary of Energy. If you would like to discuss these issues further, please contact me at 415/781-4211 Extension 2577.

Sincerely,

cc: Mr. W. J. Cavagnaro, CPUC

792234A

STATE OF WEST VIRGINIA
PUBLIC SERVICE COMMISSION
CHARLESTON, 25305

April 9, 1980

Stephen S. Skjei
Office of Utility Systems
Economic Regulatory Administration
Department of Energy
Washington, D.C. 20461

Dear Mr. Skjei:

Re: Preliminary discussion draft copy
of The Gas Rate Design Study

We have read your draft with great interest and, in general, found it both clear and informative. In response to your request for comments we have the following:

- (a) What major issues are not adequately addressed in the report; what should it say that it now does not?

Little is explained about the model which predicts increases and decreases in volumes used and numbers of customers served in the various time frames and under various scenarios. A brief explanation of the assumptions used would have been helpful.

- (b) How well are various issues treated; how can the discussion be improved?

In general, the subjects were well treated. However, there were sections where specific examples or clarifications would have been helpful. An example is the discussion of "Shortages Prior to 1985" in Chapter III, specifically page 7. It is unclear what is meant by "net national economic losses of \$1 to \$2 billion per year?" Is this based on welfare economics modeling? The explanation that losses occurred because "high valued users" had to switch to another fuel while "low valued users" received gas is perhaps too broad and could be expanded for clarification purposes.

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- (c) Where is the discussion in the report inappropriate or misleading; how can those sections be improved?

No comment.

- (d) How can the structure and format of the report be improved?

No comment.

- (e) What alternative labels for the distribution company types would make the report easier to follow?

We have no difficulty with the labels of moderate cost, high cost, and intrastate. However, it was unclear where the "reference case" of a California utility with abundant but high gas costs fell within the three general labels.

It is hoped that these comments will prove helpful to you. We look forward to seeing this report in final form.

Very truly yours,

David J. Ellis, Director
Division of Accounts,
Finance and Rates

DJE:PPS:bp

UNITED STATES OF AMERICA
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION **792235A**

In the Matter of:)
)
Gas Utility Rate Design Study:) Docket No. ERA-R-79-22
Responsibilities Under Public)
Utility Regulatory Policies Act)
of 1978)

COMMENTS OF
THE PROCESS GAS CONSUMERS GROUP
AND THE GEORGIA INDUSTRIAL GAS GROUP
ON PRELIMINARY DISCUSSION
DRAFT OF THE NATURAL GAS RATE DESIGN STUDY

Pursuant to the March 21, 1980 Memorandum of Stephen S. Skjei of the Economic Regulatory Administration ("ERA"), The Process Gas Consumers Group ("PGC") and the Georgia Industrial Gas Group ("GIG") hereby respectfully submit their comments on the Preliminary Discussion Draft of the Natural Gas Rate Design Study ("Draft Study").

I. STATEMENT OF INTEREST

PGC is an association organized to promote the development and adoption of coordinated, rational, and consistent federal and state policies which will assure an adequate and reliable supply of natural and manufactured gas at just and reasonable cost-based rates for industrial gas uses which cannot technically or economically be converted to alternative fuels. The members of PGC participating in this proceeding are: American Can Company, Armco Inc., Bethlehem Steel Corporation, Cone

Mills Corporation, General Motors Corporation, Owens-Corning Fiberglas Corporation, Owens-Illinois, Inc., and United States Steel Corporation.

Joining with PGC for the specific purpose of participating in this proceeding are the following members of the Georgia Industrial Gas Group: American Industrial Clay Company of Sandersville, Anglo-American Clays Corporation, Freeport Kaolin Company, Georgia Kaolin Company, Griffin Pipe Products Company, and Thiele Kaolin Company. These companies all operate industrial facilities which consume natural gas in the State of Georgia. (General Motors, a member of PGC, is also a member of GIG).

II. COMMENTS

As discussed in greater detail below, the Preliminary Discussion Draft of the Natural Gas Rate Design Study is seriously deficient in a number of respects. These include its failure to consider important alternatives; its failure to set forth adequately its assumptions; its failure to analyze or acknowledge serious deficiencies in the marginal cost rate structures espoused; and its failure to recognize or to acknowledge serious deficiencies in the computer model approach employed. If these defects are not corrected, the study is likely to be misleading and to produce seriously misguided conclusions.

A. The Draft Study Fails To Consider The
Fairest And Most Efficient Alternative
Available: Wellhead Price Deregulation
Accompanied By Cost Of Service Ratemaking.

Perhaps the single, most obvious flaw in the scope of the ERA's Draft Study is its failure to analyze seriously the alternative of immediate deregulation of wellhead natural gas prices accompanied by traditional utility ratemaking based on the actual costs of serving each class of end users. Although the Seventh Interim Report on Marginal Cost Pricing indicated that this alternative would be analyzed fully, and although passing reference is made to the advantages of wellhead deregulation, thorough analysis is omitted. This omission renders the Draft Study defective for both legal and practical reasons.

Section 605 of the Public Utility Regulatory Policies Act clearly requires that the impacts of alternative wellhead pricing policies be analyzed in the gas rate design study. In describing the matters to be analyzed in the ERA study, Section 605 states, in pertinent part,

Such study shall address the effect (both separately and in combination) of the following factors...: incremental pricing; marginal cost pricing; and user gas consumption taxes; wellhead natural gas pricing policies; demand-commodity rate design; declining block rates; interruptible service; seasonal rate differentials; and end user rate schedules."

By specifically including "wellhead natural gas pricing policies," Congress plainly intended ERA to consider the effect of various possible pricing policies, not just the limited decontrol

policy adopted by the Natural Gas Policy Act of 1978. Not only would an assessment of impacts from one policy be meaningless without reference to alternative policies, the obligation to consider alternative wellhead pricing policies is underscored by the reference to "wellhead natural gas pricing policies" in the plural. Also, the statute's list of areas to be studied plainly includes alternatives requiring legislative actions. Of the possible "wellhead natural gas pricing policies" available, prompt decontrol is the single most obvious alternative. Accordingly, under the terms of PURPA, wellhead price deregulation must be analyzed fully, particularly in view of the economic distortions that the Draft Study finds have resulted from pricing rules under the Natural Gas Act and NGPA.

Furthermore, apart from the legal compulsion, the ERA should fully analyze the alternative of prompt wellhead price deregulation accompanied by utility rates based on actual cost of service, because this alternative would provide the simplest, fairest, most accurate, and lowest cost method of assuring that supplies and demand for natural gas and alternative fuels are kept in equilibrium. As noted below, the advantages of this approach are many.

A free market at the wellhead is the most direct and effective means of assuring that the price signals are felt by both the supply and demand sides of the natural gas industry and that they accurately reflect the actual costs associated

with producing and transporting natural gas. Wellhead prices which reflect the market value of natural gas will assure that producers receive sufficient incentive to continue and to increase their gas exploration and development activity. At the same time, by allowing market prices to prevail, one avoids the problem of regulated and partially regulated prices creating artificial supply shortages which merely encourage sellers and regulators to resort prematurely to stop gap high cost supplemental supplies. */ Further by allowing wellhead prices to be determined by market demand, proper price signals are sent both to intermediate purchasers (pipelines and distributors) and to ultimate purchasers (end users). End users' demand for natural gas is sensitive to the price of all available substitutes, including coal, oil, propane, "waste" fuels (sawdust, wood chips), etc., as well as conservation alternatives. And because pipelines and distributors are sensitive to their end users' demand for gas, they will not bid more for gas supply than their customers are willing to pay after being charged for transmission costs. **/ Furthermore, the prompt decontrol

*/ For example with wellhead prices limited by the Natural Gas Act, a number of distributors served by interstate pipelines resorted to expensive SNG plants when lower cost supplies were physically available in intrastate markets.

**/ In other words, contrary to the implication (page V-6) in the Draft Study, one would not expect wellhead gas prices to match the price of alternate fuels. Such an approximate balance would occur only at the burner tip because it is the total cost per Btu that consumers compare in making allocation decisions between various energy sources.

of wellhead prices would eliminate the high costs associated with the administration of the NGPA's complex pricing rules. These costs are currently borne in the form of higher taxes and gas rates and lower profits.

A free market at the wellhead should, in turn, be combined with traditional, nondiscriminatory cost of service ratemaking. Under this approach, the utility would charge to each class of customer rates based upon the fully allocated cost of serving that class of customer. This approach has several major advantages. First, it is simpler and far less subject to error and abuse than alternatives that depend on theoretical economic concepts that have never been generally applied in the real world. Although some accounting questions may at times be difficult, the utility industry and its regulators have substantial experience and expertise in calculating rates based on fully allocated embedded costs. Companies and regulators can deal with measurable reality and avoid speculation about such things as "real resource costs," replacement costs of facilities, costs of competing energy sources, elasticities of supply and demand, relative costs of conservation, etc. Second, by allocating costs to classes on the basis of actual patterns of cost incurrence, one avoids both the inequities of discrimination and the economic inefficiencies flowing from subsidization of one class by another. Third, because each consumer will thereby confront the actual cost of being served

natural gas, regional mixes of fuels will reflect the least-cost combination of various fuels. Unlike a rate scheme that artificially pegs all end user gas prices to a specified oil price (as is sometimes implied in the Draft Study's marginal cost discussion), regions of the country would have varying fuels mixes that reflected relative transportation costs and demand patterns. The end result would be the most equitable and economically efficient system for matching energy demand and supply.

While the Draft Study acknowledges that full wellhead deregulation would resolve most, if not all, of the economic problems perceived with the current system of price controls, it asserts that, during a transition period in which price controlled gas is rolled-in with new volumes, gas would move from the intrastate to interstate gas markets. The theory is that interstate pipelines would be able to outbid intrastate buyers because, relying on the rolled-in prices that average price controlled gas and deregulated gas, the interstate pipeline would be able to expand its sales even if the new gas prices were well in excess of alternate fuel prices. This "problem" is mentioned a number of times during the Draft Study, but it is never seriously analyzed. Consequently, several potential limits on the underlying assumptions are never mentioned.

(a) The Draft Study implicitly assumes NGPA's limited form of decontrol and does not consider the possibility of more complete decontrol, in which price escalator clauses are fully

honored, and in which vintaging concepts are dropped in order to permit market prices at the time gas contracts "roll over."

(b) The Draft Study does not evaluate the magnitude of gas supplies that intrastate buyers were able to put under long term contracts during years of interstate price controls, when gas supplies migrated from interstate to intrastate markets. Although higher than interstate prices, the intrastate prices were well below what they will be in the future. (c) The Draft Study also assumes a rapidly expandable interstate market, and ignores the significant regulatory and physical delays associated with extending new gas service. (d) No mention is made of the fact that interstate pipelines and their distributors are already complaining that they are losing load to fuel switching and conservation even under current, controlled prices. (e) The Draft Study omits any analysis of how transportation cost differentials for interstate and intrastate pipelines would tend to mitigate the hypothesized drain. (f) The Draft Study fails to consider relatively simple and direct methods for dealing with the assumed rapid expansion of interstate markets, such as use of certificate authorities and enforcement of the Powerplant and Industrial Fuel Use Act's restrictions on gas usage by electric utilities. */ In sum, the only problem that the

*/ Restoring former levels of gas service to electric utilities --the lowest form of gas usage by virtually all standards--is the most obvious way for interstate pipelines to expand their markets at the expense of intrastate pipelines. Hence, if the DOE would

(Continued on next page)

Draft Study foresees with decontrol requires further analysis both because it appears to be overstated, and because there may be far simpler and better solutions than leaping to novel, complex, and discriminatory rate designs.

B. The Draft Study's Analysis of Marginal Cost Rate Design Is Seriously Deficient.

Although the ultimate conclusions of the study have not yet been added, the tone of the Draft Study clearly suggests that the authors plan to embrace some form of marginal cost pricing. Unfortunately, there are a number of defects in the underlying study and in the draft report explaining it. Readily apparent problems include: (1) the alternative rate structures assumed are poorly defined in the Draft Study; (2) the authors' policy objectives are not clearly enunciated and there is little clear indication of whether these goals are met or missed; (3) there is no recognition or analysis of many of the economic, equitable and administrative distortions that will be produced by the authors' preferred rate structures; and (4) the analysis is replete with problems and errors which suggest that its model is seriously defective.

(1) Failure to Define the Assumed Rate Structures.

It is impossible for a reader to begin to evaluate the Draft Study given the failure to delineate clearly the mar-

simply enforce FUA and stop granting "temporary public interest exemptions" to electric utilities, it could substantially reduce the possibility of major shifts of gas from the intrastate market.

ginal cost rate structures employed and how they are derived. Indeed, one is inclined to infer that the Draft Study's descriptions are unclear because the underlying analysis is, itself, somewhat muddled. For example, the Draft Study states (page V-2) that for "the nation as a whole, the marginal cost of gas is . . . determined by two types of real resource costs:" the cost of acquiring other substitute fuels, in particular oil, or the cost of expanding the gas supply itself. The cost of oil, one is told, is the cost of resources, goods, and services which must be exported to pay for oil imports. Then, the reader is advised (pages V-3 to -4) that the "economic costs of gas may also be defined by the costs of exploring for and/or developing new supplies," so that "[i]f these costs are lower than the price the nation pays for importing oil because gas is not available, they should be the basis for the estimates of real resources of gas." Having said this, the Draft Study simply assumes that the proper measure of oil as of the "real resource cost" is low sulfur residual fuel oil, without analysis of whether the cost of developing new gas supplies is lower than the cost of oil imports, which, at least up to a point, it certainly is.

This concept of "real resource cost" is next used to derive the Draft Study's "economic cost" rates as follows. (Page V-7) At the pipeline level, flat rates are used and are derived by adding the "real resource cost" to the pipeline's

"variable transmission cost." The distributor pays this rate to purchase gas, and presumably it adds its own costs of distribution when it resells the gas. That is, the consumer pays a price equal to the "real resource cost" (oil), plus pipeline and distribution costs. If inadequate rate recovery results, a customer charge may be added as well. Two obvious but unanswered questions are: what happens to the pipelines fixed transmission costs? and what consumers would pay for this very expensive gas? With burner-tip gas prices equal to the price of oil plus transmission and distribution costs, massive switching from gas to oil will no doubt occur.

Although the distributor presumably only adds its distribution costs to the price it pays for gas, the Draft Study is apparently concerned that the revenues recovered by the distributor may be too high; and, hence, it assumes adoption of inclining block rates at the distribution level. Again, two obvious questions arise. If the distributor has to pay the real resource cost (oil) plus the pipeline's variable transmission cost, and if it has to recover its own distribution costs well above the alternate fuel price, when would it ever worry about over-collection -- wouldn't it instead just worry about significant losses of sales? Also, although advised in vague terms that the tailblock is set at the average cost for pipeline gas and the initial block is set at whatever level is needed to reduce revenues to match the revenue requirement, the reader

must ask how initial blocks and tailblocks are actually to be designed in the different customer classes? Although the Draft Study is silent, obviously the regulator's choices would have profound effects on the fairness and efficiencies of the resulting rates and on usage patterns. To illustrate, one could achieve the same level of revenues (\$10,000) (a) by charging 100 customers 50c/Mcf for their 100 Mcf of consumption and having one large customer pay \$5.00/Mcf for his next 1000 Mcf, as (b) by charging 100 customers 90c/Mcf for their 100 Mcf and by having the one large customer pay \$1.00/Mcf for his next 1000/Mcf. One choice of blocks could lead to no conservation but serious financial hardship for the large customer, while the other might produce very different results. Unfortunately, by their silence, the authors imply that this is not a significant assumption or a potentially serious problem.

The vagueness of these and other very basic components of the Draft Study strongly suggests that the study's authors desire to provoke profound changes in gas utility rate design with only the vaguest idea about how those rates would be designed, or how those rate structures will affect the public. Fundamental policy changes that will intimately affect the structures of a crucial energy industry deserve better and more detailed support than this Draft Study offers.

(2) Failure to Identify Goals and to
Acknowledge Serious Departures
from Them.

Apart from the Draft Study's lack of clear definition of its fundamental terms, its authors fail to enunciate clearly their policy goals and, thus, fail clearly to assess how well those goals are met under the various alternatives before them. A brief examination of the identifiable goals, however, reveals that the Draft Study's preferred rate design approach does not work very well.

According to the Draft Study, wellhead price controls of the NGPA will produce shortages, and, consequently, "[t]he key concern for rate design, particularly at the distribution and pipeline company level, is to prevent the occurrence in the 1980-84 period of the misallocation and economic losses that occurred in the 1970's." In the same vein, it makes clear that achieving levels of conservation and oil imports that reflect "real resource costs" are vital. In other words, it appears that the Draft Study's major goal is to use rate design to imitate free market efficiencies (i.e., a market without price regulations). The authors would add a novel form of burner tip price regulation in order to obscure the low, controlled wellhead prices that, in turn, are blamed for obscuring the real resource cost of gas. That is, the Draft Study would compensate for bad wellhead price regulation by adding more complex burner-tip regulation.

Once one recognizes that the Draft Study's ostensible goal is to imitate free market efficiencies, one is forced to ask "If you like the efficiencies of a free market, why not opt for a free market?" Phrased otherwise, "If the problem is over-regulation, how can the correct solution be more regulation?" With these thoughts in mind, the authors of the Draft Study should revise the analysis and discussion to measure the advantages and disadvantages of the marginal cost rate solution against the implicit ideal of a free market at the wellhead. They should then attempt to explain why the free market should not similarly be adopted by promptly deregulating wellhead prices.

Such an analysis would quickly reveal a number of serious disadvantages of the rate design "solution" to the wellhead price control problem.

First, the rate design solution is grotesquely complex. Not only would it be virtually impossible to determine on a continuous basis the "real resource cost" to be used in setting prices, translating that into reasonable, workable flat or inverted rates for every pipeline and distribution company would be a nightmare. In hundreds of rate cases across the country (or worse, in one national rate case), experts would debate over complex market forces including what the "real resource costs" are; what the relevant elasticities are; whether revenues will be recovered; where inverted blocks should be

set; etc. Inevitably, the result would be inaccurate and only the degree of inaccuracy would vary. The results could be seriously wrong, at least for some classes of affected persons.

Second, the marginal cost rate design approach suggested in the study would be inherently discriminatory because it ignores the relative costs of serving different classes of customers. For example, flat rates would discriminate between temperature sensitive (e.g., residential) and high load factor (e.g., industrial) customer classes, by charging rates without regard to the relative costs of serving the different groups. Discrimination would occur within customer classes under inverted rates because rates would vary according to the size of the consumer and without regard to the relative cost of serving it. Consequently, a large, high load factor industrial would be forced to subsidize a small low load factor industrial, even though it is cheaper to serve the former. Further, the Draft Study's rate design may result in interregional subsidies if, for example, pipelines really are expected to charge only for variable, not fixed, transportation costs and if the burner tip price is geared to some national estimate of "real resource" (oil) costs. Unfortunately, the study's rate assumptions are defined so poorly as to make this difficult to determine what would happen here.

Third, just as the novel rate designs would discriminate, so would they cause serious distortions from the cross

subsidies implicit therein. In other words, the new rate designs necessarily create a new set of misleading price signals. To illustrate, under inclining block rates, one would see larger users forced to bear larger costs without regard to the relative economics of service and without regard to the relative ability to convert or conserve. Thus, a small, poorly insulated residence would face lower unit prices, than a larger more tightly built home, simply because of size, not because of relative costs of service conservation costs. Although, under the study, this problem would be carried forward on a large scale in the form of industrial "lifeline" rates, the inevitable distortions from the misleading price signals is nowhere acknowledged. The result might be no additional conservation or relatively high cost conservation measures or plant closings, but the "least cost" solution would not be adopted.

Fourth, severe revenue stability problems could be created for utilities. Obviously, the more that costs are loaded into the tailblocks, the greater the likelihood of large revenue swings. Moderate changes in demand due to economic conditions or competing fuels prices could lead to major shifts in revenue levels. Further, to the extent the burner-tip price for gas is fixed to match the substitute fuel price closely, consumers capable of switching are more likely to switch between fuels to take advantage of minor price changes. Since gas utility rates cannot change rapidly enough to match oil

price movements, a sudden softening of oil prices (as has recently happened) could lead to significant load shifts and corresponding increases in oil imports. Unfortunately, the draft rate design study ignores this and asserts, without analysis, that revenues will be more stable under marginal cost pricing.

Fifth, the marginal cost rate design solution ignores supply side economics. To producers, marginal cost calculations are relevant only in deciding whether to invest in new exploration and development. If they do not receive the proceeds of the Draft Study's marginal cost rates, they will not be influenced in their exploration decisions. In other words, distortions in supply and demand will necessarily remain under the rate design approach to coping with problems created by well-head price controls.

(4) The Underlying Study Is Defective As A Tool For Policymaking.

Apart from the foregoing failures to analyze and discuss major problems with the rate designs espoused on the Draft Study, it is apparent that the underlying computer methodology is itself defective.

First, a computer simulation model is an inherently poor tool for making policy decisions in an area as complex as energy markets. Economic forecasting models may be helpful in illustrating the interrelationship between various aspects of the economy. However, reliance on the results of such fore-

casting can be very misleading, particularly in an area as volatile and unpredictable as future energy costs. No model can conceivably include accurate assumptions about enough variables to predict price, supply and demand patterns for natural gas over a 10 year period as this model purports to do. The model used by ERA would appear to be even more subject to error than typical forecasting models. This is because assumptions have to be made about facts and relationships for which there is little or no empirical evidence or support. For example, the model's predictions are based upon elasticities of demand and supply which cannot have any historical validity as modern society has never experienced prices anywhere near as high as those contained in the model. Similarly, it is impossible to assess accurately and predict the energy costs since gas and oil prices have historically been controlled politically and they are increasingly influenced by non-economic forces. */ Likewise, it is impossible to predict relationships between energy costs and the future cost of the various other commodities, which compete with energy for the consumer's dollar, since the future overall product mix of society is impossible to predict with accuracy. As the Draft Study itself acknowledges,

*/ Recent history graphically illustrates the critically important role played by non-economic events in our economy. Both the price and supply of internationally traded oil and gas is determined not merely on the basis of traditional economic analysis, but is strongly influenced by political and social factors.

the model does not apply to any real world utility or its customers. Nevertheless, by using a model to produce specific sets of numbers, the computer simulation approach has the insidious effect of implying precision where nothing remotely resembling precision exists. In this regard, the Draft Study is particularly misleading because it is written in such positive predictive tones.

Second, there are obvious serious flaws in the assumptions and formulae underlying the model. This can be inferred from information in the Draft Study, even though the factual assumptions are not spelled out in the document. For example, examination of Tables 1 and 2 in Chapter IV reveals several bizarre relationships in which there is absolutely no fit between percentage changes in price and demand. Between 1980 and 1990, an industrial customer of a moderate cost utility shows a 4.7% increase in consumption following an 85% increase in price, while an industrial customer of a high cost utility shows a 64% decrease in consumption following a 65% increase in rates. */ With the high cost utility using declining block rates, a 60% increase in rates to industrials produces a 9.3% decrease in average usage; while with the same utility using volumetric rates, a 47% increase in price produces a 69.4% in-

*/ This cannot be explained by Table 13's assumption of a mass exodus of industrial customers from the high cost utility in that period because Table 2 speaks of average consumption per customer.

crease in average industrial demand. The latter increase in demand is particularly strange inasmuch as the average price of \$6.87/dth in 1990 is by far the highest industrial rate under any scenario. Examination of calculated price increase effects on industrial demand served by an intrastate utility also reveals inexplicable patterns.

Other flaws are apparent when one considers the relative consumption patterns assumed or produced for residentials, and the absolute changes are also unrealistic. Hence, for a residential customer of the moderate cost utility with flat rates, a 71% increase in price causes a 24% decrease in consumption--far more residential conservation than has occurred in the last decade from a far larger increase in gas rates. Without expanding the list of obvious defects, here we would note that there are also clear factual errors in the text of the draft. Indeed, the more we examine the Draft Study the more defects we find, and we plan to continue to examine the document.

Because of the importance of, and apparent defects in, the many critical assumptions underlying the Draft Study, the numerous assumptions and the basis therefor should be clearly stated in the next draft of the report. Without a comprehensive listing of assumptions about prices for alternative fuels and conservation investments, elasticities of demand by customer class, prices of competing goods and services (they will indi-

rectly reflect gas price increases), patterns of reduced usage due to plant closings, the actual block structures used in rate setting (instead of references to average prices), etc., no one can begin to evaluate the meaningfulness of the study. From what can be told, however, the Draft Study appears to prove nothing more than that computers can generate numbers. That is hardly helpful in designing policies.

III., CONCLUSION

In sum, the Draft Study is patently inadequate in several respects. The analysis must be expanded to consider the advantage of prompt wellhead price decontrol, and it must be expanded to more candidly acknowledge the serious drawbacks in the marginal cost rate designs espoused. In addition, the study should be substantially rewritten to describe in detail both the numerous assumptions underlying the computer model and the inherent deficiencies in using simple models to predict actual behavior, over a long period of time, in a complex world. Further, the study should more clearly spell out the authors' policy objectives, and it should acknowledge the serious problems that will result from the new rate schemes.

Finally, the study should ultimately recommend the simplest, most equitable, and most efficient economic solution: prompt decontrol of wellhead natural gas prices accompanied by fully allocated cost of service ratemaking. The Draft Study recognizes that this Nation's problems with natural gas supply

and demand, including the shortages of the 1970's and the likely shortages of the next few years, can be traced directly to federal policies regulating wellhead prices. Although the ultimate utility rates are necessarily affected by low wellhead prices, the traditional utility ratemaking principles, in themselves, do not create significant problems, since they fully allocate actual costs to classes of users in accordance with actual patterns of cost incurrence. Now, in an effort to compensate for a bad federal policy of wellhead price controls, the authors of the Draft Study would apparently abandon the one well-established and economically sound form of gas pricing regulation--fully allocated cost ratemaking--in favor of experimental burner-tip pricing policies. This, we submit, defies common sense and would be poor policy. The only reasonable solution is one which is not adequately analyzed in the Draft Study, prompt deregulation of wellhead prices accompanied by actual cost of service ratemaking.

Respectfully submitted,

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
ECONOMIC REGULATORY ADMINISTRATION

792236A

Natural Gas Rate)
Design Study:)
Preliminary Discussion)
Draft)

ERA Docket No. ERA-R-79-22

WRITTEN COMMENTS OF THE AMERICAN GAS ASSOCIATION

The American Gas Association (A.G.A.) is a national trade association comprised of more than 300 natural gas transmission and distribution companies which provide natural gas to approximately 160 million consumers in all 50 states. Indeed, A.G.A. member companies account for about 85% of all natural gas utility sales in our nation.

We wish to take this opportunity to set forth our comments, concerns and recommendations regarding the Preliminary Discussion Draft of the Natural Gas Rate Design Study (hereinafter referred to as "Draft"). With respect to the specific questions which accompanied the Draft and which concern specific aspects of it, A.G.A. believes that such questions more easily lend themselves to textual discussion rather than specific, enumerated responses. Therefore, our general discussion will address, in whole or in part, the questions which ERA has posed.

The following comments are divided into two parts. The first concerns general considerations regarding the Draft and rate design theory in general. The second part raises specific questions and concerns which A.G.A. has regarding specific aspects, techniques and assumptions contained in the Draft.

Introduction

A.G.A. believes it is important to recognize at the outset of these comments that existing, traditional gas rate designs are the product of years of deliberation, fine tuning and adjustments to meet various requirements. These rates have been found by State regulatory commissions to be fair, just and non-discriminatory. Indeed, existing rates presently incorporate, to the extent possible given the social and political climate within the State, all three of PURPA's purposes, viz., conservation, efficient use of utility facilities and resources, and equitable rates to gas consumers.

In light of the above assertion, we believe it is essential that ERA give these assertions careful and close scrutiny in order to lend credibility and accuracy to the Gas Utility Rate Design Study. (See Sections II and III for more detailed discussion of this issue.) This close examination is necessary if ERA is to render a fair assessment of existing rate designs as compared to alternative and innovative rate concepts such as marginal cost pricing. Practically speaking, it defies logic and reason to embark upon a rate design study of wholly novel, untried and untested rate design concepts before having fully assessed the existing rate design practices of the gas utility industry.

Finally, A.G.A. wishes to stress the importance of having an opportunity to review the Gas Rate Design Study prior to May 9, 1980 when it will be submitted to Congress. To deny this opportunity for final review of the draft report, would preclude the possibility of valuable input, comments and recommendations from the regulated gas utility industry and other interested parties. Also, to deny this review of the final draft report would risk the possibility of

including in that report misleading, ambiguous and possibly incorrect material. Further, this opportunity for review is of particular importance because the Preliminary Discussion Draft lacks ERA's final conclusions regarding the assessment of the various rate structures considered in the study. The Draft does not now provide a comparative analysis of all the alternative rate structures required to be studied. Therefore, an opportunity to review the final draft before submission to Congress is deemed essential by the regulated gas utility industry, and is in fact required pursuant to Section 306 (a) and (d) of PURPA.

Summary of A.G.A.'s Comments and Recommendations Regarding the Draft

- o ERA risks unpredictable and possibly disastrous results by endorsing a novel, untried, and untested marginal cost pricing rate concept. A.G.A. believes that no such endorsement is warranted without first determining: (1) whether ERA's assumptions surrounding marginal cost pricing and existing gas utility rate design are reasonable; and, (2) whether the costs of utilizing a marginal pricing cost theory in gas rate design are offset by the benefits derived therefrom. (See I, infra.)
- o ERA has addressed the existing gas utility rate design concepts (cost-of-service and rolled-in pricing) in a superficial manner and in a negative light. (See II, infra.)
- o Existing rate design has been effective as a conservation incentive. As natural gas wellhead prices continue to rise, this conservation incentive will continue to grow. (See III, infra.)
- o It appears that ERA has based its analysis of distribution company marginal cost pricing rate designs on real resource cost pipeline rates. This is not the most realistic approach to analyzing the distribution rate designs in the Draft. (See IV, infra.)
- o A.G.A. maintains that ERA's reliance (for purposes of Chapter V, Marginal Cost Pricing) on DOE's Technical Staff Analysis (which projects possible future market conditions) is ill-advised because of the deficiencies inherent in that analysis. (See V, infra.)

- o ERA recognizes that marginal cost pricing's alleged "price signal" would cause substantial fuel switching by large volume users (mostly interruptibles) due to higher priced tailblocks. What ERA does not seemingly recognize, however, is the potential for major economic dislocation due to industrial relocation resulting from the imposition of a marginal cost pricing theory. (See VI, infra.)
- o Marginal cost pricing creates an inherent bias against the development of supplemental gas supply projects. This bias is short-sighted and ill-advised if the United States is to reduce its reliance on foreign oil. (See VII, infra.)
- o Marginal cost pricing will create additional revenue instability and uncertainty for the natural gas utility industry because weather-related usage fluctuations will occur in marginally priced blocks for residential and some commercial users. (See VIII, infra.)
- o Marginal cost pricing, as envisioned by ERA, would discriminate against gas energy in that most energy supply industries (e.g. electric and domestic oil) do not marginally price their products. To impose an economic penalty on gas users -- and not impose it on fuel oil or electricity consumers -- would seriously undermine the market for natural gas. (See IX, infra.)
- o ERA's recommended use of inverted rates, to conform revenue requirements, will preclude effective conservation price signals from reaching small and medium volume users in both residential and commercial classes. (See X, infra.)
- o Consumers are more likely to receive a conservation price signal from the aggregate utility bill rather than from the the cost of the last unit. (See XI, infra.)
- o Attempts to create a conservation price signal on the basis of the last unit's costs are confounded by "levelized" payment plans provided to consumers by gas utilities. (See XII, infra.)
- o The rate design recommended to conform revenue requirements (inverted rates) does not track cost causation and, therefore, frustrates the "equitable rates to gas consumers" purpose of PURPA. (See XIII, infra.)
- o It must be recognized that ERA's use of synthetic utilities cannot be used as an accurate reflection of the response of "real world" utilities to the rate designs studies. (See XIV, infra.)

- o A.G.A. believes that ERA must consider the long-range impacts of any recommendations in order to preclude the possibility of working irreparable harm to the nation, the economy, and to a vital national industry (i.e., the regulated natural gas industry). (See XV, infra.)
- o Rate design and the theory on which it is based should not be considered a panacea to cure our nation's energy problems. (See XVI, infra.)

I. ERA Should Not Endorse Any Innovative Rate Design Until the Gas Utility Rate Design Study Fully Analyzes and Assesses the Assumptions and Conclusions Underlying that Rate Design and Determines it to be Cost-Justified

It appears that ERA has overlooked a primary and major deficiency underlying the marginal cost pricing theory. Whereas existing cost-of-service pricing is essentially a delicately balanced and finely tuned rate design (as mentioned in the introductory comments above and in II infra) marginal cost pricing is skewed in that it imposes a disproportionate cost burden on large volume users. With the hope of gaining an effective conservation price signal, ERA, through an implied endorsement of marginal cost pricing, has wholly abandoned the benefits and other desirable characteristics which cost-of-service and rolled-in pricing provide.

To credibly assess marginal cost pricing theory, ERA must determine the accuracy of its assumption that consumers in fact receive a conservation price signal from the last unit's cost rather than the aggregate utility bill. (This is discussed in greater detail at XI, infra.) Also, to determine whether the marginal cost pricing theory is cost justified, ERA must make a close examination of whether the 18 to 25% load loss (and the other negative impacts which are projected to occur) will, on balance, despite the alledged conservation benefits, have an adverse impact on the economy and the regulated gas utility industry. Another related factor which ERA

must address in its cost-justification is whether the imposition of a marginal cost pricing theory, as opposed to existing cost-of-service/rolled-in pricing, is prudent in view of the seemingly major economic dislocation and industrial relocation (see VI, infra) which will very likely occur under marginal cost pricing rate design theory.

II. Existing Rate Design Has Not Been Fully and Fairly Assessed in the Draft

We understand that a complete comparison of the alternative rate forms is yet to come. However, since such great criticism was leveled at existing rate designs, the Draft should fully and fairly analyze these rate designs. ERA based its attack on existing rate designs on an unsubstantiated DOE Technical Staff Analysis which is discussed in detail infra at V. ERA has apparently failed to recognize or take into consideration that existing rate designs are the function of years of adjustment and fine tuning and are essentially delicately balanced concepts, fully accepted by State regulatory commissions. Whereas marginal cost pricing is skewed in its impacts, most existing rate design concepts consider several factors to achieve a balanced design. These include: (a) load factors; (b) revenue requirements of the utility; (c) revenue stability of the utility; and, (d) cost-of-service based rates so as to fully allocate the cost of providing service to those customers causing the utility to incur such costs. ERA has failed to discuss the positive aspects derived from existing rate designs insofar as those designs consider all of these factors in determining the make-up of a customer's rates.

It seems ERA's general indictment of existing rates is that the tailblock rates are generally lower and, therefore, are in effect a conservation disincentive. It is important to recognize, however, that most of a utility's fixed costs are recovered in the initial blocks. The decline in tailblocks is due to a smaller amount of the fixed costs being recovered in these blocks. Therefore, reduced rates in the tailblocks reflect that the utility's overall costs of providing service in these tailblocks are less than in the initial blocks. Moreover, not all companies have declining block rates for large customers under present rate structures.

III. An A.G.A. Analysis Reveals that Substantial Conservation in the Residential Sector Has Taken Place Under Existing Rate Design

In particular, in ERA's unsubstantiated and incomplete assessment of existing rate design, they have made only conjectural projections as to what the conservation effect has been under traditional cost-of-service or rolled-in pricing. They have offered no conservation data or figures to support their statements and, therefore, the Draft lacks credibility and objectivity in this respect. An A.G.A. analysis revealed that under existing rate design conservation has indeed been realized. That analysis found that between 1973 and 1978 a significant amount of conservation has occurred in the residential gas space heating market. In that period, average conservation is estimated to have been between 12 and 14% below pre-1973 levels, with savings as high as 20% in some regions.^{1/} It should be noted that these figures

^{1/} Evaluation of Energy Conservation in the Residential Gas Space Heating Market: 1979 Update, American Gas Association; Arlington, Virginia; December 14, 1979.

are only for the residential sector and do not estimate the conservation response after 1978. With increased public awareness of the need to conserve energy, it is likely that these percentages are increasing for both residential, commercial and industrial users. Moreover, as wellhead natural gas prices continue to rise, this conservation price signal will be enhanced.

IV. Analyses of the Distribution Company Marginal Cost Pricing Rate Designs in the Draft Should Not Be Based on Real Resource Cost Pipeline Rates

In Chapter V at page 7, the Draft states that real resource cost pipeline rates will be used in analyzing distribution company marginal cost pricing rates. However, a more realistic approach in analyzing such distribution company marginal cost pricing rate designs would not utilize real resource cost pipeline rates. This is true because all pipeline rates are based on rolled-in, and not real resource cost pricing. If ERA's purpose underlying the gas utility rate design study is to provide State commissions with an opportunity to review comparative distribution company rate designs, particularly marginal cost pricing, then the Draft should analyze these rate designs in a context within which State commissions can realistically appraise them. Therefore, the Draft should assess the distribution company marginal cost rates in the context of existing pipeline rate structures, which are based on rolled-in pricing and not on real resource costs.

V. DOE's Technical Staff Analysis on Which Chapter V, Marginal Cost Pricing is Based, is Deficient and Unsubstantiated in Many Respects

In forecasting the future gas supply scenario, the staff analysis is pessimistic, to the point of being unrealistic, in projecting the contribution from supplemental gas supply projects. This is particularly the case in regard to the contributions of LDC and SNG, which are completely disregarded. With respect to new technologies and North American imports, the DOE forecasts are well below industrial projections.

In addition, all of the unsatisfied gas demand which the staff analysis projects occurs in the very low priority use sector of gas demand (viz., industrial boilers and powerplant use). However, to the extent that such uses are not now "existing" and/or not covered by one of the exemption regulations promulgated pursuant to the Powerplant and Industrial Fuel Use Act (PIUA), they will very likely be prohibited from being hooked up because of the PIUA constraints. Therefore, the amount of unsatisfied gas demand which ERA anticipates may, in reality, not be as great as projected.

In regard to the forecasted misallocation of supplies, the staff analysis contends that aggressive bidding, well above fuel oil parity, by interstate pipelines for deregulated gas will be the primary factor causing such misallocation. This assertion is based upon the proposition that such interstate pipelines will have large amounts of "old" gas into which they can roll-in the high cost of new expensive gas. This rationale breaks down insofar as we are not experiencing such behavior in present contract negotiations and bidding for deregulated deep gas. If the staff analysis supposition were in fact correct, one would expect that current deregulated deep gas contracts would be much higher.

For these reasons, we believe that the validity of ERA's marginal cost pricing Seventh Interim Report and Chapter V of the Draft is questionable given the deficiencies in the Technical Staff Analysis on which the Report and Draft are based.

VI. The Fuel Switching and Industrial Load Loss Caused by Marginal Cost Pricing's Disproportionate Impact and High-Priced Tailblocks Would very Likely Cause Major Economic Dislocation and a Significant Increase in Fuel Oil Use

ERA projects that there will be between 18 to 25% industrial load loss due to fuel switching caused by marginal cost pricing (Chapter V, page 23 of the Draft). As interruptible and large volume users (and high priority users with alternative fuel capability) switch from natural gas to some alternative fuel, the impact on our nation's economy may be greater than that expected simply by reason of such fuel conversion. Such greater impact may result from these large users not only switching fuel, but relocating their industrial facilities to achieve the most cost effective operating conditions. For example, such large users may move to the "sunbelt" regions to afford reduced plant maintenance fuel costs. In switching to alternative fuels, such plants may require retrofitting to permit the use of another fuel. These users may find it in their best interest to relocate to an area in which the alternative fuel to which they are switching is cheaper and more abundant, i.e., moving to the upper Northwest where electricity generated by hydropower is cheaper, or moving to where coal is cheaper or where clean air standards permit its use.

The combination of both fuel switching and industrial relocation could have a substantial adverse impact on the economy. Whole regions of the nation could be affected insofar as certain industries find it is no longer feasible or cost effective to

remain in those regions. The impacts of such industrial relocation would be widespread and range from the increased costs of the goods and services provided by the relocating industries to the rise in unemployment in the abandoned areas.

The impacts of fuel switching on individual high priority customers are also very apparent. When a large volume user switches fuel, the necessary result is that the same fixed costs must be borne by a fewer number of ratepayers. In this manner, the remaining customers suffer increased fixed cost charges. To the extent that a utility experiences substantial fuel switching, this added cost burden on the remaining customers can be great.

VII. Marginal Cost Pricing Creates an Inherent Bias Against the Development of Supplemental Supply Projects

In view of the fact that we have a clearly established national goal to develop our domestic energy resources, it is particularly imprudent and ill-advised to impose marginal cost pricing on gas utilities. Marginal cost theory will create an inherent bias against the development of supplemental gas supply projects (e.g. new technologies, SNG and Alaskan gas) since most new gas supply projects have high capital costs and produce gas at initially higher prices. However, under a system of cost-of-service/rolled-in pricing, new gas supplies can be rolled-in with existing supplies without causing major economic dislocation to the users of that gas. In fact, the cost of these supplemental supplies will become competitive over the life of the project. A marginal cost pricing system, however, would frustrate the development of these domestic gas supplies and increase our reliance on foreign oil.

VIII. Marginal Cost Pricing Theory, if Implemented by Inverted Rates, Would Likely Impose Greater Uncertainty and Instability on the Gas Utility Industry

Under present rate designs, as compared to inverted rates under marginal cost pricing, a utility is afforded greater certainty, predictability and revenue stability. This is true because present rates, which price the tailblock at lower unit charges, would allow less variation in revenues due to the vagaries of weather. Under a marginal cost pricing theory using inverted rates, however, much of a utility's revenues result from the high marginal costs of the tailblock units. Therefore, any weather fluctuations causing less consumption in the blocks would substantially reduce the utility's revenue receipts.

It is unclear in the Draft whether the structure of the inverted rates contemplated to conform revenue requirements will in fact shift some of the utility's fixed costs from the initial blocks to the tailblock. If such shifting is indeed contemplated, then the usage fluctuations described above would very likely result in a substantial and serious reduction in the utility's operating income. Severe fluctuations could result in a net operating loss for the utility.

In addition, inverted rates under marginal cost pricing and the resultant revenue instability could cause yet another problem. Many utilities have long-term gas contracts including non-negotiable take-or-pay provisions. Insofar as marginal cost pricing would essentially eliminate a utility's interruptible load sales by causing fuel-switching, the utility is further subjected to potential operating deficits. These deficits could occur in a mild winter when demand for gas for spaceheating is depressed, and a utility is, by reason of such take-or-pay provisions, forced to pay a penalty for not taking delivery. This penalty usually amounts to

the demand charge plus the commodity charge for 75% of the utility's entitlement under the contract. With no interruptible load balancing sales to absorb this "take-or-pay" gas, these penalty payments could be so severe as to cause a utility to experience a net operating loss.

IX. Imposition of Marginal Cost Pricing on the Gas Utility Industry Would Create Inequitable Results Insofar as Competing Fuels are Not Marginally Priced

Traditional economic theory maintains that a marginal cost pricing system will not work unless all competing forms of energy are priced pursuant to a comparable "marginal" theory. It is apparent in the instant case that not all of the competitive energy forms are priced on a marginal cost basis. This is particularly true with respect to electricity and domestic oil (notwithstanding future decontrol) which are not priced at the marginal cost. For this reason, imposition of a marginal cost theory on the gas industry can only lead to a distortion in gas rates and usage, as compared to these other fuels.

It should be noted that in hearings on alternative rate design concepts, State commissions have without exception rejected the implementation of marginal cost pricing rates for electric utilities.

X. Inverted Rates Under a Marginal Cost Pricing Theory Will Preclude Small and Medium Volume Residential, Commercial and Industrial Users From Receiving Conservation Price Signals

In addition to the possibility of under-recovery mentioned above, a very real possibility exists that the use of higher marginal cost rates for all users would produce revenues far in excess of the allowable levels. ERA has advanced a means (inverted rates) by which these "excess revenues" could be returned by reducing the rates for small and medium volume users in residential, commercial and industrial classes. By so doing, however, ERA has embraced the proposition that such consumers would be least likely to increase

their energy consumption because of lower rates. This wholly denies ERA's alleged purpose of providing a strong conservation incentive to all consumers and, in fact, creates a conservation disincentive for these particular consumers. This is a wholly unreasonable position especially in light of the fact that these segments hold a large conservation potential. To provide generally lower rates to these sectors would ignore this conservation potential. Therefore, ERA's endorsement of inverted rate design schedule would in fact directly frustrate all three of PURPA's purposes, viz., to promote both conservation and the efficient use of gas utility facilities and resources and to provide equitable rates to gas consumers.

Indeed, even ERA recognizes in Chapter V of the Draft at pages 15 and 16 that both small commercial users and residential users generally will experience a lower average price for gas. Furthermore, they admit that in these cases there will be no conservation incentive. Moreover, this result will serve to frustrate the Residential Conservation Service Program because it removes the economic incentive to conserve for customers.

XI. The Aggregate Utility Bill, Not the Last Unit's Cost, will Provide the Consumer with a Conservation Price Signal

The "price signal" can occur at numerous different points on the scale of usage depending on the individual customer's characteristics. Within a class of service, the twentieth, fiftieth, or even eight hundredth therm (or an infinite number of other points) may be the additional therm for a customer.

Moreover, there is further evidence to suggest that the aggregate size of the bill, rather than the cost of the last unit, is the "price signal" really understood by customers. If marginal cost pricing were applied to a distribution company's rate design, a radical and sudden change from present rate structures

would likely occur. In this respect, the aggregate bill received by the consumer, rather than the last unit's cost, offers the simplest and most readily ascertainable "price signal" for such consumer.

Practically, for the customer to receive a "price signal" from the last unit's cost, he would have to: read his own meter; know how close he is to the marginally priced unit; know when his meter was and will be read; and, be able to predict the weather. Clearly, it is highly improbable that any "price signal" arises for most customers from the last unit's cost.

XII. "Levelized" Bill Payment Plans Will Frustrate Any Last Unit's Conservation Price Signal

Many regulated gas utilities offer their customers

"levelized" payment plans which permit the spreading of costs over a year and allow the consumer to pay an average monthly bill (e.g. budget billing plans). This practice affords the customer some relief from receiving disproportionately large bills during the winter heating season and relatively small bills in the summer season. Such payment plans offer a very effective income management tool, and will in fact take on increasing importance, and probably be more widely used, as the economy moves through the present recessionary period. However, marginal cost pricing may effectively deny ratepayers the benefits of a budget billing plan. This is a possibility insofar as constantly fluctuating tailblock prices under marginal cost pricing may render budget billings an administratively unworkable concept.

In the event that a customer elects to utilize such "levelized" payment plans, and to the extent such plans are more widely utilized, any particular conservation price signal which ERA has intended the customer to receive through the bill would be wholly illusory because the bill the customer receives is an average, taken over a 12-month period.

XIII. Inverted Rates Are Essentially Inequitable Because They Deny Ratemaking Based on Cost Responsibility

If a marginal cost pricing rate theory is to utilize inverted rates to implement such theory, the result essentially is inequitable and unjust to the price-elastic loads (generally considered to be commercial and industrial users). This is true insofar as the price-elastic loads receive high marginal prices while the "excess revenues", which arise from such high marginal costs in the tailblocks, are returned to the residential and small commercial and industrial user. Such a practice wholly denies the traditional and equitable ratemaking concept of rates based on the cost of providing service to a particular customer (i.e., cost-of-service ratemaking).

ERA recognizes this inequity but accepts it as necessary. In Chapter V of the Draft at page 15, ERA discusses that it is in fact the real resource cost of gas which is the primary determinant of commodity charges for gas. Therefore, residential contributions to overhead costs are lower under marginal cost pricing while industrial customers make a relatively higher contribution to meeting these fixed or overhead costs. The result for industrial and large volume users is a disproportionately high commodity charge when compared to the actual costs which these customers cause the utility to incur on their behalf. The inequity in such a result is even more apparent when one recognizes that those customers bearing the disproportionately high commodity charges are providing load balancing benefits to the remaining customers.

XIV. ERA's Synthetic Utilities Will Not Accurately Reflect the Impact of Marginal Cost Pricing for All Utilities

It must be noted that each utility is a unique entity encompassing many factors, not the least of which are its geographical, climatological, economic and political characteristics. To the extent

that ERA utilizes only three synthetic utilities to assess rate design impacts, the obvious limitations on the applicability of the results must be recognized. In this respect, no generalized statements of rate impacts can accurately be applied to an individual utility to assess its response under a given rate concept.

XV ERA's Discussion of Long-Term National Impacts Fails to Address Several Points

The national impacts of the imposition of a marginal cost pricing theory are discussed only in terms of the alleged problems which ERA identified pursuant to the DOE Technical Staff Analysis problems which in fact are not substantiated by DOE or ERA. The listing of national impacts does not include the national impact created by marginal cost pricing's inherent bias against supplemental gas supply projects. The likely impact from this bias would be to decrease domestic gas supply and provide a barrier to reaching our goal of energy independence. (See VII, supra.) Moreover, the list of national impacts does not discuss the possibility, or the impact, of industrial relocation and the regional, economic deterioration, rise in unemployment, or inflation caused thereby. (See Introduction and VI, supra.) There is also no discussion of the inflationary impact of passing on the higher marginal costs in the tailblocks to large volume industrial and commercial users. Undoubtedly, such higher costs of gas in these tailblocks will be passed on to consumers through increased prices for the goods and services produced by these large volume industrial and commercial users.

XVI. Rate Design Theory Should Not be Viewed as the Sole Means of Solving Our Domestic Energy Problems

Rate design should not be viewed as a panacea to solve our energy problems. Rather, rate design should be one of many balanced approaches, which, in conjunction, can be used to achieve a consciousness in consumers that energy conservation is of paramount importance for our nation. For example, when coupled with existing rate design, the utilization of energy tax credits for expenditures on energy conservation measures (such as more efficient replacement gas furnaces, vent dampers, etc.) could be a very effective conservation inducement. Under such approach, the delicate balance already achieved in existing rate designs (supra, at II) would not be foresaken and the more equitable cost-of-service determination would remain the basis of rate design.

Specific Questions and Concerns Which A.G.A. has Regarding Certain Aspects, Techniques and Assumptions Contained in the Draft

The primary concern we would like to stress in this part of these comments is that it is crucially important that ERA recognize (1) the difference between cost causation and rate design, and (2) what each is intended to accomplish. Cost causation (or cost responsibility) is wholly attributable to the type of customer, his capacity requirements, and his commodity component. Cost causation serves as the basis on which a utility allocates the costs of providing service to a particular customer or class of customers. Rate design (or rate structure) on the other hand, is not a means of allocating or determining costs; it is a means of recovering costs equitably. This pricing mechanism (i.e., rate design) does not, in any way, affect the allocation of costs or cost causation.

This is particularly important for ERA to note as they have at times apparently disregarded (or at least failed to recognize) the two concepts. In Chapter II of the Draft at page 27, ERA notes, without explanation, that large users pay less than residential customers under declining block rates. The missing, and essential, explanation reveals that large users pay less than residential customers per unit of consumption because the latter class causes the utility to incur more fixed costs per unit of gas consumed than the former does. The declining block rate simply reveals this cost causation difference and equitably recovers the costs of providing service from each class.

On pages 3, 9 and 17 of Chapter IV, ERA again refers to costs being allocated or assigned to customer classes in a specific manner by a specific rate. Again, this is entirely incorrect.

The following is a list of page-specific comments and recommendations regarding the Draft. These are identified first by the Chapter of the Draft and then, more specifically, by the page on which they appear.

Chapter I

Page 2: The statement is made at the bottom of the page that "investor owned utilities have in many instances, also been allowed to base their rates on average costs." (Emphasis added.) The implication is that the utility elected this method of basing rates, when in fact they are required to follow average cost pricing.

Chapter II

Page 5: The 37% figure representing the gas heat share of the new housing market appears to be on the low side. If this figure is correct, the types of new housing (i.e., multi-family structures which generally are more adaptable to other heating systems) should be considered and identified as a causative factor, in addition to hook-up moratoria.

Electric resistance heat should be described as "usually much more expensive to operate."

- Page 12: In Figure II-3, the accuracy of most demand occurring in February is problematic in that this month is generally milder and has fewer days.
- Page 14: It is confusing to state at the bottom of the page that "intrastate pipelines were able to raise prices faster during the 1970s then (sic) interstate pipelines." The real reason for the price hike was lack of federal regulation at the local level. Government restraints, and not length of existing contracts, inhibited interstate pipelines from competing with intrastate pipelines for gas.
- Page 18: At the bottom of the page, the terms "average amounts per day", "percent of remaining reserves available" and "independent variation from distributors demand schedule" are foreign concepts to the regulated gas utility industry.
- Page 19: Pipeline tariffs do not ordinarily set forth the two rate components separately even though they exist.
- Page 20: The first full paragraph should also point out that any pipeline paying excessive prices for gas runs a significant risk that such gas is unmarketable.
- Page 24: A.G.A. endorses the statement that "the effect (of revenues instability from weather fluctuations) can be mitigated by keeping rates low in the section of rate structure most subject to such volume changes." This is one of the principal objectives of declining block rate structures.

Chapter III

- Page 4: In the last line of the first full paragraph, the words "interstate" and "intrastate" are transposed. The statement that incremental pricing was designed to encourage conservation and alternate fuel use, including switching to fuel oil, is wholly inconsistent with our national energy goals.

The load loss discussion does not mention the adverse impacts which such load losses would have on high priority and commercial markets.

- Page 5: The statement regarding "prospect of supply shortages", at the bottom of the page, is inaccurate unless some unforeseeable barriers to present production develop.

Page 7: If in fact ERA's intent is to protect the intrastate market, it is doing so at the expense of the interstate market and customers in that market.

Chapter IV

Page 1: In the first sentence the permissive "permit" should be changed to a mandatory "require".

Page 4: It should be noted here that volumetric rates are not a method of allocating costs to customer classes because they completely fail to recognize cost causation. To the extent which volumetric rates do not track costs, they violate the "equitable rates for gas consumers" purpose of PURPA.

Page 5: The statement that the distribution company fixed costs will rise by 10-20% from 1980-1990 seems unrealistically low in light of present inflation rates.

Page 10: The statement is made that "the larger the customer, the larger is the degree of conservation." There is no foundation for this statement because conservation depends not only on price, but also upon the demand elasticity of the users. It is conceivable that a large user would have a greater need for gas and therefore cannot conserve vast amounts.

Page 16: In any climate and for any size residence, it is difficult to conceive of a customer using 400 DTH per month.

Page 22: It is misleading to say that interruptible service is the "generally cheapest approach". Further, it is misleading to state that storage facilities increase fixed costs and raise accounting based costs. These claims by ERA cannot be made in a vacuum without pointing out that, because gas can be sold to industrials on a firm year-round basis at higher charges than interruptible charges, these incremental costs are more than offset.

The \$.21 storage figure cost seems unreasonably low.

Page 24: Volumetric rates are presumed to assess the same charge per unit for all classes of service. In the discharge of volumetric rates on this page if ERA enlists this presumption, surely the rates charged for interruptible (and hence inferior) service would be unlawfully discriminatory as compared to the rates for year-round service. It would appear that, under the assumptions set forth in the Draft, volumetric rates and interruptible service are mutually exclusive.

Page 28: Phase II of incremental pricing under the Natural Gas Policy Act of 1978 could moot ERA's conclusions about industrial customers switching from oil to gas.

Page 31: The scenario developed at the bottom of the page is unrealistic inasmuch as price rises will inevitably cause reduced volumes of sales. The only difference occasioned by rate forms will be differences in degree which probably will be slight.

The comment on this page that a high cost distributor may benefit from incremental pricing from other distributors on its pipeline assumes the absence of state plans to eliminate MSAC's.

Most important, however, is the logical and realistic extension which develops from the load loss scenario discussed in the middle paragraph on this page. If there is an inference that load deliveries under volumetric rates are desirable in terms of conservation, the following must be noted. As deliveries decline, the absorption of fixed costs per unit for all categories of remaining customers increases; such increased costs, of course, create a strong conservation incentive but also increase the rate of load loss and decline in deliveries. Carried to its ultimate conclusion the industry ceases to operate as an effective energy supplier. Conservation is accomplished, but it is a Pyrrhic victory.

Page 33: The comments regarding the role of interruptible customers at the top of the page should be accompanied by the following considerations. Interruptible sales can be continued only if: (1) the price of the gas in such sales remains competitive with the alternate fuel; and (2) the price of the gas provides a profit over the appropriate cost of such gas supplies.

Pages 36 and 37: We commend the logic implicit in the discussion under the heading "Revenue Stability" at these pages.

Page 37: We express serious doubts that there are "a significant number of distributors" who cannot purchase enough gas to supply their demand at present. Moreover, we seriously question the assumption of a pipeline supply 30% below demand.

Chapter V

- Page 2: The description of the components associated with customer and capacity costs is greatly oversimplified.
- Page 3: Less gas is available for other consumers when some consumers use gas instead of coal only under situations in which supply and demand are in balance or a shortage of supply exists.
- Page 5: It is specified that the first block would reflect the costs of price controlled gas plus pipeline fixed costs. There is a longstanding regulatory principle that customers paying the lowest prices are curtailed first. Does theory set forth on page 5 imply that small users paying a price based on controlled gas would be the ones to be curtailed in the event of a possible shortage because of inadequate supplies of old controlled gas?

The suggested changes to pipeline rates are overly general and simplistic. Would the size of the first block be based on a volumetric limit? Would it be the same for each rate zone and customer class? Or would it be based on a set percentage use of each customer's contract demand?

Inverted block pipeline rates would not necessarily result in distributor's establishing like rates - they would probably prefer to work on average costs. Distributors today are recovering average gas costs from customers, which are less than the most expensive purchased supply.

- Page 6: The statement is made that pipelines would only purchase gas at prices which the consumers at that time would be willing to pay. This logical objective is true under any rational pricing system, be it marginal or rolled-in. Pipeline suppliers are generally aware of their distribution company customers ability to market gas at varying prices.
- Page 10: It is difficult to believe that price increases under the proposed marginal cost rates are similar to those under the accounting cost approach. The proposed marginal approach would result in substantial load loss for consumption in the tail blocks, where the marginal price is used. If in fact fixed costs are assessed in this marginal cost tail block, the inability to recover them, because of the lost consumption, would impose an additional price burden on the remaining consumers. Indeed, it is likely that a sizable number of large commercial and industrial users, when faced with the proposed marginal costs rates, would use gas up to the trigger point, and then use the alternate fuel for additional needs.

It should also be noted here that any novel rate design (marginal cost pricing included) must provide a utility the opportunity to achieve the return authorized.

- Page 11: To provide a fair assessment of the situation, the concern about protecting intrastate distributors must also include a discussion of the impacts of the offset to interstate pipeline bidding capability.
- Page 12: Here and on several other pages the use of the term "lifeline" is misapplied, particularly since the reduced charges for the initial block are applicable to commercial and industrial as well as residential.
- Page 13: Table 1 would be easier to understand if the columns had appropriate headings.
- Page 16: There is no discussion of the design of the industrial inverted block rates, i.e., whether they are based on size, load factor or something else. This is an oversimplification.
- Page 17: The statement is made that industrial customer contributions to fixed overhead costs are higher with economic costs rates. This is surely true per customer, but the substantial loss of customers would result in substantially lower aggregate recovery from the class.
- Page 24: The "Volumes" section should have a conclusion which states:
- Economic cost rates have minor impact on intrastate utilities but result in sales volume reductions of 18% - 25% for interstate utilities.
- Page 26: There is no consideration here of the distributor with storage capability and little, if any, developed interruptible market.

Conclusion

A.G.A. requests that the foregoing observations, comments and recommendations be carefully considered by ERA during the final stages of work on the gas utility rate design study. In addition, we reiterate our belief that it is essential, and required, that ERA make the final rate design study available for public review prior to being submitted to Congress on May 9, 1980.

Respectfully submitted,

THE AMERICAN GAS ASSOCIATION

By

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CHARLES H. FRAZIER
DIRECTOR PHILADELPHIA OFFICE

March 26, 1980

Mr. Stephen S. Skjei
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Economic Regulatory Administration
Department of Energy
2000 M Street, N.W.
Washington, D.C. 20461

Dear Mr. Skjei:

Comments in re Preliminary Discussion Draft
of the Gas Rate Design Study

Thank you for sending me the March 21 draft of the Natural Gas Rate Design Study. It is a most interesting document, pointing up many of the considerations we have been raising for some time. I have not been close enough to this particular endeavor to offer you any detailed discussion of the draft; but there are a few general observations which could be made which might lead to a strengthening of the document. These are not of an editorial nature, but rather questions of approach.

The first observation I would make relates to the lack of consideration of coal as a competitor of gas--the document concentrates on the relationship between gas and oil pricing and assumes that it is that relationship which needs to be considered in evaluating proposed gas price reforms. For much of this century however, gas use has been limited, in major parts of the country and for numerically significant quantities (e.g., boiler fuel for industry and public utilities), by the price comparison with coal, which price competition, until the early 1970s, succeeded in keeping gas demand and supply in balance. I strongly suspect that beginning now, this role for coal prices will be resumed and that with the increasing interrelationship between oil and gas prices (viz., Canada's recent price action), it is the cost of the environmentally-satisfactory burning of coal

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that will provide the real economic test as to whether expensive supplemental supplies of gas are economically demanded. This is already happening in many places. The reliance of the authors of the document on the price of heavy oil as the competitive test is, for much of the country, misplaced. Keep in mind that the swing volumes of gas, around 6 Tcf out of a total of 20 Tcf, are used for boiler fuel, where coal--even with expensive scrubbing, etc.--can be competitive; certainly given time for equipment changes.

The second observation I would make has to do with the definition of marginal cost. Over and over again the writers of the document define marginal cost as the cost of the "next decatherm" of gas the market demands. This of course is the text book definition. Nevertheless, as a practical matter, if we are talking about resource cost in terms of the various policy alternatives the country faces, we need to be thinking of the cost of the marginal blocks of gas, involving relatively large quantities of incremental gas supply. The swing requirements of gas, largely in the boiler fuel area, which need to be met by swing supplies, as we question whether there is a demand for such supplies, are, importantly, additional Canadian and Mexican imports, gas from tight sands (here and in Canada) and, possibly, gas from coal. It may be anticipated that all conventional resources will be exploited, including the Overthrust Belt, deeper drilling, etc.--in any event, within the general range of prices now considered compensatory for such efforts and leaving gas competitive in most markets. The determination of marginal cost to be used in pricing, as I have visualized it, does involve judgment, it is true: there is probably no one right number, and it does change over time. Nevertheless, it is better to make a reasonable estimate of this standard than let the thing go by default, as we are now doing, and completely underprice gas supplies.

The third area I would comment on, requiring some consideration in your Chapter V, is that marginal cost pricing almost by definition includes the time-of-use element. Gas use, of course, for a half of the annual total, is highly temperature-sensitive, peaking up in the wintertime, and this is the area where increased demands are being felt. There will be a marginal supply cost of gas (as above discussed), but also a marginal storage cost for gas sold in

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the severe winter months. There are other incremental costs of course, but these are the major ones that vary with volume. To omit the marginal storage cost for pricing gas for use during the winter is to omit a significant marginal cost.

Finally, in the discussion in Chapter V on whose marginal supply cost to use, there is the assumption that the FERC will not do anything in the visible future to rectify its inattention to economic pricing for pipeline rates. It is the obsolete pipeline rate structures which raise the issue of "distributors' incremental cost," as being much lower than national (social?) marginal cost. True, incremental cost pricing, imposed at the congressional level, does begin to impose some economic pricing sanction on the industry, in default of the FERC having undertaken this at an earlier point in time. Unfortunately, all this does is to muddy the waters, were the FERC disposed to eliminate the dilemma you pose between the use of national marginal cost and distributors' marginal cost. It seems to me that the discussions could well point to the need for FERC responding to the economic pricing challenge, in seriously revising its pipeline rate design procedures (omitting from consideration, for the moment, the "wrinkle" caused by NGPA "incremental pricing"). You have pointed out some of the mechanics by which the "just and reasonable" revenue requirements of the pipelines can be brought in line with the revenues which would flow from economic rates. It behooves FERC to get on with this exercise of its ratemaking jurisdiction, long neglected, as a part of the endeavor resulting from the congressionally-mandated rate reform study. Recognition of the need for this might well be reflected in your document.

Sincerely,

CHF:nhc

The Petrochemical Energy Group

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April 30, 1980

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Dear Mr. Skjei:

The Petrochemical Energy Group (PEG), an ad hoc group of independent petrochemical companies, has participated, at the Department of Energy's (DOE's) invitation, in various stages of the preparation of the natural gas rate design study mandated by Section 306 of the Public Utility Regulatory Policies Act (PURPA), Pub. L. No. 95-617, 92 Stat. 3117 (1978). We look forward to continuing this participation, particularly as DOE moves from the theoretical study represented by its current draft */ to the stage of formulating recommendations. Since PEG's member companies utilize natural gas as both a fuel and a feedstock, PEG is vitally interested in DOE's natural gas rate design study and subsequent recommendations. Members of PEG's Technical Subcommittee have reviewed the draft and offer the following general comments:

1. Section 306 of PURPA provides for DOE to study and report to Congress on various approaches to gas utility rate design. Based upon this report, DOE is to prepare proposals to improve gas utility rate design and to encourage conservation of natural gas. These proposals and

*/ March, 1980, "Natural Gas Rate Design" (Preliminary Discussion Draft).

any legislative recommendations are to be transmitted to each House of Congress not later than six months after the date of submission of the study on natural gas rate design. We assume that the March, 1980 draft is the first or general analysis phase of the PURPA-mandated process. It should, consequently, evaluate alternatives impartially, without arguing implicitly or explicitly for any single alternative rate design. However, the section of this March, 1980 draft on economic cost pricing appears to be an indirect endorsement and is inappropriate.

2. The draft report is also deficient in that it does not include any indication of DOE evaluation of the validity of the model's results when compared with the actual experience of gas utilities with these economic rate designs.

3. The study does not appear to take into account that industrial use of natural gas encompasses several types of specific applications. As noted in Chapter II at pp. 7-9 industrial users may utilize natural gas for process uses or as a raw material or feedstock, or as boiler fuel. However, Appendix B to the January, 1980 draft of the study, which presents the methodology used to estimate industrial demands, does not make any distinction between these various uses of natural gas. Yet these distinct industrial uses of natural gas will probably respond differently to price increases since feedstock and process users have no practicable substitute for natural gas while boiler fuel users can usually switch to other fuels, such as oil.

Further, the study assumes that the industrial decision to switch from gas to an alternate fuel will be based totally upon the cost of the natural gas and the cost of the alternate fuel. Such a limitation on the stimuli for switching to an alternate fuel appears to be unrealistic. Energy and Environment Analysis, Inc. prepared a draft report for the DOE entitled "Methodology for Assessing the Impacts of Alternative Rate Designs on Industrial Energy Use," (January 11, 1980). The consultants considered the costs of fuel switching for both boiler and non-boiler utilization of natural gas, and delineated a number of factors under both categories of natural gas use. The March, 1980 draft of the natural gas rate design study, in contrast, appears to overly simplify the industrial decision to switch to an alternate fuel.

4. It is not clear whether the analysis of the revenues derived from the various rate forms considered will be designed to reflect the cost of service to the various customers. It appears that the analysis of the adequacy of the revenues derived from a particular rate form are investigated on a system-wide basis only.

5. The March, 1980 draft does not adequately assess whether any of the "economic cost" rates discussed would overcome the alleged deficiencies of rolled-in pricing, e.g. obscuring the real economic cost of gas to consumers, which the draft states is one of the problems of current natural gas rate designs. While the report points to some theoretical approaches that will remove some of the former difficulties and distortions caused by rolled-in pricing, it appears that new distortions could possibly occur under the untried, economic rate designs. For example, it is not clear whether the economic rates have high cost gas, such as SNG, rolled-in (albiet in the highest rate block), resulting in selling SNG at less than its economic cost.

6. In order to prevent an over-recovery of costs under marginal cost pricing, the report suggests that the lower-cost, old, controlled natural gas be sold first. But the report does not analyze the serious problems associated with determining who is entitled to this lower-cost gas -- e.g., how much of this gas are new customers entitled to, who should give up entitlements to old gas to supply new customers, etc.

7. Although the impact of various rate designs on consumer gas purchasing decisions is analyzed, the impact on purchasing decisions of the gas utilities is not discussed. For example, should old, price-controlled gas be dumped under boilers in the summer? What gas should utilities purchase for storage? If high-priced gas is put into storage and not sold during the subsequent winter heating season, how will the utility be reimbursed?

We hope that these comments will be useful and look forward to seeing further development of the study.

Very truly yours,

Stanley B. Farbstein

Chairman of
THE PETROCHEMICAL ENERGY GROUP

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May 6, 1980

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Re: Draft Report of DOE
Gas Rate Design Study

Dear Steve,

Find enclosed additional comments of the People's Counsel of Maryland. We comment with some specificity about a number of issues. I am wholly convinced that the many, competing "equity" issues that will arise on a case by case basis have not surfaced in the DOE study; nor have commentators upon the study identified all relevant equity considerations.

A maximal weighting of marginal costs into rate formulae needs to occur. Public acceptance of rate reform initiatives is dependent upon implementation that avoids abrupt consumer impact. The DOE study is a valuable document and provides an excellent overview of the gas industry. However, as comprehensive as the study is, state regulators will, and should, be the ones who wrestle with the implementation of new rate forms whose impact on a case by case basis will vary greatly from distributor to distributor. The latter is implicitly recognized in the Study which finally settled in on three broad types of distributors. You easily could have called them Northeast, Producing, and Other States. With labels such as this, the likely variation in rate effects would be more prominent than they are with the current descriptions (high cost, moderate cost, etc.).

Mr. Stephen S. Skjei

May 6, 1980

Thank you for the opportunity to see and review the interim reports and to meet and confer with the project officers and contractors along the way. We have profited from the experience as will our clients in whose behalf we will continue to advocate continuous rate improvement which includes weighting economic concepts of cost as heavily as can reasonably be done case by case.

Sincerely,

JOHN K. KEANE, JR.
PEOPLE'S COUNSEL

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Enclosure

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March 21, 1980

ADDITIONAL COMMENTS OF THE PEOPLE'S COUNSEL
OF MARYLAND REGARDING THE DEPARTMENT OF
ENERGY GAS RATE DESIGN STUDY

The study appears to be very thorough. The modeling is useful insofar as it goes regarding types of utility systems and types of utility rate designs. However, it is clear from the report that not enough is known about gas rate design to have the federal government actually setting retail gas rate design. The better legislative model is that of the electric rate standards in PURPA. It is suggested that what is needed is more information and consideration by state regulatory agencies and FERC of the important rate design issues, with a bias toward the economic approach which apparently is favored by the office of utility systems. It is generally agreed by consumer advocates and many state commissions that rate recognition of marginal or incremental costs is appropriate for the setting of utility rates; be they electric, gas, telephone or water. However, in the gas area in particular where the marginal costs currently are substantially higher than the embedded costs this must be done very carefully. With the revenue constraint involved in traditional rate setting there can be a 100% increase in rates caused by the marginal cost

approach. It can be appropriate to make adjustments for inelastic use, especially if in a social equity analysis found that this would benefit lower income persons and moderate income persons, without doing damage to the states or federal economy. However, this must be approached on a meaningful level and issues such as the actual elasticity of demand and relative usage levels for both urban and rural poor of natural gas must be studied.

The interests of all sectors of society should be represented in the process. DOE should recommend to the Congress that the states must consider marginal costs, that the larger utilities must study and report marginal costs, and that they need also study and report the social and economic impact of adopting marginal cost rates, marginal cost-based rates, and annual accounting cost rates.

Adequate funding should be provided for state commissions and for consumer intervenors to assure broad based representation for all sectors of society.

The final legislative report should include for state commission consideration the identification in the mid and long term of an economic supply of gas together with the likelihood of various rate forms resulting in an economic demand scenario for the mid to long term. Mid-term as used herein includes the time period 1985-2000. The long term is the period beyond the year 2000. The rate forms to be considered are those included in the DOE study. In addition, the relationship to existing incremental pricing

rules and the practices regarding p.g.a. need be included.

SUBSTANTIVE ISSUES

As indicated before the report does consider a broad range of variables but has some shortages of consideration. One glaring deficiency is the lack of social and economic impact analysis. It is indicated at the beginning that a contractor was at least studying the impact on low income persons but that does not appear in the report. But in addition to impact on low income persons there are issues of employment impact on middle class consumers and small businesses as well as on deficiency of industrial production. Another area which is not considered effectively is the possibility of summer-winter differentials or degree sensitive rates in causing improved load factors.

Another area which is not considered is the full marginal social costs of switching from natural gas to alternatives such as residual fuel oil and coal. Present provisions of the Power Plant Industrial Fuel Use Act do not make a distinction between natural gas and oil eventhough natural gas is generally domestic while oil is substantially imported. However, a good argument can be made both in terms of direct costs and health costs that a switch to oil or coal can cause substantial air and water polution which is a cost to society and that rate design for gas should reflect the differential marginal social costs. The only comment which seems to recognize this is page 9 of Chapter 3 where it is stated:

"Gas rate design must promote levels of conservation which are in accord with the value of gas reducing oil imports."

There are different ways in which gas can be used and it should be used most efficiently. The comment is made in a number of places that the increased prices will "drive industrial users off the system" and that small volume users would then become responsible for the fixed costs formerly assumed by these large volume users. (This appears at page 9 and similar comments at page 19 and 26 of Chapter 4). The argument is that industrial users will switch to residual oil. In addition to any other possible legal constraints there is the point of differential cost for conversion if a user presently does not have oil or coal capability. The experience in the case of National Fuel Gas Company and Brooklyn Union Gas Company is that there are users who will stay using natural gas even where the cost of the gas is above the cost of residual oil.

The study does show a concern with revenue stability which would be an important factor certainly in state rate setting and of course would be a reason why there should be no abrupt changes in utility rates. There is not enough experience in use of inverted rates or even marginal cost rates for natural gas to see what the revenue stability would be and that would be another reason to wait for complete implementation of this type of rate design at least as a mandated federal requirement.

The draft report in many places observes that one rate form causes more or less conservation than another, yet the report does not hint at which level of gas usage approaches

the appropriate level of conservation. It would seem rational to approach the problem from a competition-emulating point of view. An economic demand scenario should by the end of the mid-term (The year 2000) result in the gas industry providing X% of the nation's energy supply ("X" quads). If certain rate forms lead to the use of more, or what is equally important, less gas than that level, the the rate form (s) recommended should exclude those which waste resources (gas, capital, labor...all the inputs of production). Previous comments of People's Counsel were aimed at this issue, but the draft report seemingly does not reference it. It is reasonable at this point to believe that decontrol can result in the desirable, economic market conditions by the mid-term. If this is so, regulators should be directing their efforts toward equity objectives. As noted in previously filed comments, the Study is weak on equity issues..

ELASTICITY ANALYSIS

The model used for the simulations appears to be quite sophisticated. There is no explanation for the assumptions made on "conservation" which is used in the report as a surrogate for elasticity of demand. The only elasticity appears to be reduction in over-all natural gas usage. Some comments were previously made by a Dr. John A. Neary on behalf of People's Counsel which criticized the demand model for its lack of robustness. It was noted at the time that this part of the model was to be improved. However, it does not appear in the report whether or not this was done. If in fact variables such as relative energy prices, new construction activity, appliance saturation rates, income and linkage to non-heating customers conversion to heating customer category are used, then this should be clearly indicated. At least such variable should be indicated in a footnote or in an appendix. It is anticipated that Congressional staff persons when reviewing the report will check such assumptions and the report therefore would anticipate this type of question.

Another factor which appears not to be considered in the report is the end use profile problem. It is indicated in the high cost category as differentiated from the moderate cost category in the computer runs that the high cost gas model is of a utility which is primarily residential and commercial while the moderate cost utility is assumed to be heavily industrial. However, at no point is it indicated that depending upon the kind of incremental pricing adopted there can be a very different price signal faced by distribution company exempt customers. Specifically, where a utility such as Washington Gas

Light Company has a very high proportion of residential use depending on whether incremental pricing is based upon a pipeline or State basis there can be very different prices faced by exempt consumers. It is unfair to have such differences and it can be argued that Congress has intended to have a fair allocation of such costs and benefits which flow from incremental pricing. However, even in the absence of Congressional intent on the issue it is clear that Congress wished to have the end-use profile problem studied, yet the report does not explicitly deal with the economic impact of the alternative forms of regulation. At this time FERC is considering statewide exemptions. People's Counsel and others have asked FERC to have its staff analyze the issue. If FERC does, then some cross data could be used.

Another area of apparent deficiency in the report is the intra-state gas company model in so far as the model appears to be based on Louisiana or Texas type systems. The usage levels in type of mix in Kansas and New Mexico, in particular, are very different than in Louisiana and Texas and yet New Mexico, Kansas, Oklahoma, California and Utah taken together provide a very substantial amount of the continental U.S. natural gas supply. One key difference between New Mexico and Louisiana is the fact that New Mexico has controlled old intra-state natural gas prices. This state control is recognized in the Natural Gas Policy Act in a specific section of PURPA (§602A, 92 stat. 3411).

Another difference of intra-state systems which is not fully explored in the report is the feed-stock and other off-peak uses of Natural Gas, such as agricultural irrigation in gas producing states. As noted in the report improved load factor reduces overall costs to the extent that rates provide for usage which is off-peak which then terminates on-peak. There can be substantially improved load factors even in gas using states such as New York where a temperature sensitive rate for gas cogeneration such as that of Brooklyn Union Gas may provide substantial benefits to all consumers.

ECONOMIC IMPACT ON RESIDENTIAL CUSTOMERS

In Chapter 5, page 14 and 15, there is a good discussion of inverted rates based upon marginal costs with the use of a "lifeline". It does appear that such a rate would be beneficial to the residential class while at the same time encouraging conservation. However, there are possible problems of lack of equity in so far as traditional tail block rates for certain large residential users tend to be low. In particular there are a great many persons who have large houses, in rural and urban areas, which are poorly insulated and which are high users of gas. It may be beneficial to consider setting aside some of the excess revenue for marginal cost to insulate such houses and or trailers as a way of inducing conservation while at the same time not harming persons who cannot afford substantially increased natural gas rates. Such a system, if there is no other adequate weatherization assistance, may be valid and would not interfere with the price signals of the marginal cost based tailblock. The People's Counsel finds such an inverted rate based on marginal cost to be attractive on its surface, but is wary of predictable future misapplication of the theory.¹ Another problem could be that implementation could have a disparate impact

¹ As noted in previous comments, there is in People's Counsel's opinion considerable risk that rate inversion will be misapplied over time. While it might be done "right" the first time, the likelihood is that subsequent changes will result in several sets of ascending blocks for any number of wrong reasons. This happened with declining blocks and will doubtless happen with inverted blocks as a result of lack of continuity among governmental bodies and interest group pressures.

on particular sub-groups of consumers. Clearly there should be full studies at the state commission before there is any implementation, although this should not be an excuse for multi-year hearings. A specific problem with inverted rates is locating the break point for blocking. One solution is the absence of a summer/winter differential is to choose the average residential use with a two block rate. Another alternative if the revenue constraints work out properly would be to eliminate the customer charge but keep in place a minimum bill and then reduce the charge for the first amounts of natural gas down to a nominal level until such point as the projected revenue excess for marginal cost is eliminated. Any over or under recovery of gas costs from the projection could be collected or refunded by way of periodic adjustment in the Purchase Gas Adjustment Clause. The inversion at the average peak residential use was adopted in 1979 by the New Mexico Public Service Commission. A similar approach with the operating adjustment has been used for electric utilities in New Mexico and most recently by the Michigan Commission in a Detroit Edison case (1980).

LEGAL CONSIDERATIONS

The report completely ignores three legal problems and it should at least address the issues. They are the end use profile consideration, the impact of the National Environmental Policy Act and the Power Plant and Industrial Fuel Use Act. The end use profile problem is directly referred to in the Public Utility Regulatory Policy Act section which creates this study.

The National Environmental Policy Act requires that an environmental impact statement be issued wherever a federal action will take place which has substantial impact on the environment. This report was specifically commissioned by Congress and perhaps would not in and of itself be subject to NEPA; however, the DOE report will recommend particular legislation. Ordinarily legislation which has a substantial environmental impact requires an environmental impact statement. At a minimum, the report should have a negative declaration of lack of requirement for an environmental impact statement with a specific basis for that claim.

Related to the issue of an environmental impact statement, is the impact on environmental quality of different gas rate designs. To a certain extent a switch from natural gas to residual oil or coal by various different users will cause deterioration in the environment. This could have an impact on particular state implementation plans under the Clean Air Act and Clean Water Act as well as upon implementation plans resultant from local law.

It may be argued that in the absence of a requirement in the law that those that pay the marginal cost of natural gas or the incremental cost under present incremental pricing could not switch from natural gas to oil when there would be a pollution effect, the result of gas rate design changes could be to cause more importation of oil rather than less importation of oil. The argument regarding switching from gas to oil particularly in periods which are off-peak for natural gas also relates to the Power Plant Industrial Fuel Use Act which has prohibition orders required against certain industrial boiler fuel users and utilities. The effect of the Act may relate directly to the use of natural gas. In particular, cogeneration with a dual fuel capability arguably comes under the provisions of Power Plant Industrial Fuel Use Act as well as under the §210 of PURPA. Since federal policy is to encourage cogeneration, dual fuel cogeneration should be considered in the report.

SUMMARY

Legislative recommendations should be directed toward State implementation of gas rate design changes. Legislative initiatives should be directed toward broad policy objectives and should make provision for thorough consideration by the states of marginal costs; for larger utilities to study and report marginal costs; for evaluating social and economic impact of rate design initiatives; for funding of State Commissions and consumer intervenors; for identification of the desirable, economic level of gas usage for the mid-term; for explicit consideration of rate forms included in the DOE Study; and for explicit consideration of phasing so as to avoid abrupt impacts upon consumers.

Respectfully submitted,

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PEOPLE'S COUNSEL OF MARYLAND

JKK/et