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## I. INTRODUCTION

President Carter has characterized the need to establish a new national plan for dealing with the energy problems of the 1970's and 1980's as "the moral equivalent of war."[1] The issue that has presented by far the greatest impediment to the establishment of a national energy policy is the pricing of natural gas.[2] Natural gas accounts for almost thirty percent of the annual energy consumption in the United States.[3] Yet, as all participants in the natural gas pricing debate agreed, the present method of setting natural gas

1. 13 WEEKLY COMP. OF PRES. DOC. 561 (April 25, 1977).

2. The Natural Gas Act requires the Federal Power Commission (FPC) to regulate the rates that producers of natural gas can charge for gas sold for resale in interstate commerce, but it does not empower the FPC to regulate the rate that can be charged for gas sold in intrastate commerce. 15 U.S.C. §§ 717-717w (1976). *See* Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954). The Department of Energy Organization Act transferred the FPC's power to regulate producer rates to the Federal Energy Regulatory Commission (FERC) in August 1977. Pub. L. No. 95-91, § 402, 91 Stat. 565 (1977) (to be codified in scattered sections of 15, 16, 42 U.S.C.).

On April 29, 1977, President Carter proposed the National Energy Act, which would have extended FPC jurisdiction to the rates charged by producers for gas sold in intrasate commerce. *See* 207 ENERGY MNGM'T (CCH), No. 204, pt. 4 (May 4, 1977). On August 5, 1977, the House of Representatives passed the National Energy Act by a vote of 244 to 177. H.R. 8444, 95th Cong., 1st Sess., 123 CONG. REC. 8826-27 (daily ed. Aug. 5, 1977). The provisions of the Bill relating to natural gas pricing were almost identical to those contained in the Carter Administration's bill. *See* 123 CONG. REC. 8309-13 (daily ed. Aug. 2, 1977). An attempt to amend the Administration's Bill through a substitute that would have eliminated federal control over all producer sales of "new" gas was defeated in the House by a vote of 227 to 199. 123 CONG. REC. 8417 (daily ed. Aug. 3, 1977). Thus, the Carter Administration and the House of Representatives went on record in favor of extending federal control over producer prices to the intrastate market.

On October 4, 1977, however, the Senate passed the Natural Gas Act Amendments of 1977 by a vote of 50 to 46. H.R. 5289, 95th Cong., 1st Sess., 123 CONG. REC. 16,323-25 (daily ed. Oct. 4, 1977). The Senate Bill rejected the approach taken by the Carter Administration and the House, and eliminated all federal control over the rates that producers could charge for "new" gas sold to either the intrastate or interstate markets. The House and Senate conferees on the National Energy Act reached a compromise that will retain federal wellhead rate regulation for the interstate market and extend federal regulation to the intrastate market through January 1, 1985. *See* note 8 *infra* and accompanying text.

3. AMERICAN GAS ASSOCIATION, LNG FACT BOOK 1 (1977) [hereinafter cited as LNG FACT BOOK].

prices creates a market in which severe and protracted supply shortages are inevitable.[4] Since 1970 the serious imperfections in the regulated gas market have been manifested visibly and painfully in the form of shortages that have required adoption of curtailment plans, complex administrative procedures that allocate scarce gas supplies among competing consumers.[5] The widespread unemployment, economic dislocation, and near disastrous inability to supply residences with gas for heating[6] during the 1976-1977 winter were only precursors of the conditions that could be expected in the future if the present system of pricing natural gas were retained.

To date most of the debate on natural gas pricing has centered around the issue of wellhead rate regulation; specifically, should "new" gas supplies sold to the interstate market be deregulated, or should federal rate regulation be extended to "new" gas sold to the intrastate market. This issue has been continuously before Congress in various forms for the past twenty-eight years. On at least three occasions during this period—in 1950, 1955, and 1975—it has appeared to be near resolution, but impasses between the House and Senate or between the administrative and legislative branches

4. The jurisdictional dichotomy between gas sold in interstate commerce and gas sold in intrastate commerce has produced a situation in which most gas producers have a choice between selling newly discovered gas in the regulated interstate market or in the unregulated intrastate market. As a result, only a small fraction of new gas reserves are dedicated to the interstate market. Legislators supporting deregulation propose to eliminate this dichotomy by deregulating the rates that producers can charge for newly discovered reserves sold to the interstate market, while the opponents of deregulation would remove the dichotomy by extending federal regulation to the rates that producers charge for sales of newly discovered gas sold to the intrastate market.

5. The term "curtailment" as used by the FPC and the FERC means the difference between the amount of gas that an interstate pipeline is required by contract or certificate to deliver and tbe amount it is actually able to deliver. The first curtailments occurred in 1970-71 and were only 0.1 trillion cubic feet (TCF), or about 0.7% of the total contractual obligations of interstate pipelines. The amount of curtailment has increased steadily each year since 1970, with the volumes curtailed in 1976-77 reaching 3.4 TCF, or about 23% of pipelines' total contractual obligations. *See* S. HERMAN, R. PIERCE, M. TROPIN, & B. TYREE, NATURAL GAS USERS' HANDBOOK 3 (1976) [hereinafter cited as NATURAL GAS HANDBOOK]. *See generally* FEDERAL POWER COMMISSION, REQUIREMENTS, CURTAILMENTS, AND DELIVERIES OF INTERSTATE PIPELINE COMPANIES BASED ON FORM 16 REPORTS REQUIRED TO BE FILED ON APRIL 30, 1977 (1977).

Curtailment plans consist of the provisions of each pipeline's tariff that govern tbe manner in which the pipeline's curtailment, or inability to meet its contractual obligations, is allocated among the pipeline's customers. *See generally* NATURAL GAS HANDBOOK, *supra*.

6. During the 1976-77 winter, gas curtailments forced the closing of 4000 manufacturing plants, with over 1.2 million people temporarily unemployed as a result. In addition, hundreds of schools were closed in several states, and over 100 fires were started in Philadelpbia as people attempted to heat their homes without gas. SURCOMM. OF INTERGOVERNMENTAL RELATIONS OF THE SENATE COMM. ON GOVERNMENTAL AFFAIRS, REPORT ON THE 95TH CONG., 1ST. SESS., STATUS OF THE NATION'S PREPAREDNESS FOR THE WINTER OF 1977-78, at 4 (1977).

of government have forestalled a resolution of the issue.[7] The most recent philosophical differences between the House and the Senate over the issue of wellhead rate regulation finally were resolved by a very complex compromise[8] associated with the Carter Administration's National Energy Act.[9] The compromise was passed by the House and Senate[10] as the Natural Gas Policy Act of 1978.[11]

During recent years, considerable controversy also has arisen concerning the manner in which the costs of providing natural gas service are apportioned among customers and consumers at the wholesale (pipeline) and retail (distributor) levels. Debate over natural gas rate design has taken place in Federal Power Commission

7. In 1947 the Supreme Court held that sales of gas for resale in interstate commerce by producers that are also interstate pipelines are subject to FPC rate regulation under the Natural Gas Act. Interstate Natural Gas Co. v. FPC, 331 U.S. 682 (1947). In 1950 Congress passed a Bill specifically exempting sales by gas producers from FPC rate regulation, but the bill was vetoed by President Truman. 1950 PUB. PAPERS 257-58 (1965). In 1954 the Supreme Court held that sales for resale in interstate commerce by independent producers also are subject to FPC rate regulation. Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954). In 1955 Congress again passed a Bill exempting producer sales from FPC jurisdiction, but this time the Bill was vetoed by President Eisenhower, 1956 PUB. PAPERS 256-57 (1958). In 1975 the Senate passed by a vote of 58 to 32 a Bill that would have removed FPC jurisdiction over the prices that producers could charge for "new" gas. S. 2310, 94th Cong., 1st Sess., 121 CONG. REC. 33,655-59 (1975). The House, however, passed by a vote of 205 to 194 a Bill that extended FPC jurisdiction to the rates that producers could charge for sales in intrastate commerce. H.R. 9464, 94th Cong., 2d Sess., 122 CONG. REC. 778 (daily ed. Feb. 5, 1976). The sharp differences between the two bills presented no room for compromise in Conference, and no legislation resulted. For the resolution of the differences between the House and the Senate in the somewhat similar debates in the 1977-1978 session, see notes 8-11 *infra* and accompanying text.

8. Under the compromise, federal wellhead rate regulation will be retained for the interstate market and extended to the intrastate market through January 1, 1985. The regulatory scheme in effect during this period will be extraordinarily complex and difficult to understand in detail. Approximately 19 different kinds of gas will exist during this period for rate regulation purposes, and the maximum ceiling price at which gas can be sold will vary widely depending upon such factors as: whether the gas is onshore or offshore, from a new or old reservoir, from a new or old well, from a well shallower or deeper than 5000 feet, from a well more or less than 2½ miles from the nearest old well, from a property previously dedicated to interstate or intrastate commerce under a contract that expires by its own terms, and whether the gas is from conventional or "high cost" sources. Each combination of these and other factors will trigger a different method of calculating the ceiling price at which the gas will be sold between 1978 and 1985, and the ceiling price for each class of gas sold during this period will increase annually by a percentage determined in accordance with a statutory price escalation formula. After January 1, 1985, all "new" gas will no longer be subject to federal rate regulation. Between July 1, 1985, and July 1, 1987, however, either Congress or the President (subject to veto by both Houses of Congress) can reimpose price controls on new gas for a maximum of 18 months without passing new legislation. After July 1, 1987, wellhead rate regulation of "new" gas can be imposed only through new legislation.

9. The original act proposed by the Carter Administration is reprinted in 207 ENERGY MNGM'T (CCH) No. 204, pt. 4 (May 4, 1977).

10. 124 CONG. REC. 16,265 (daily ed. Sept. 27, 1978); 124 CONG. REC. 13,426-27 (daily ed. Oct. 14, 1978).

11. Pub. L. No. 95-621.

(FPC) and Federal Energy Regulatory Commission (FERC) proceedings,[12] in Congress,[13] and in some state utility commission proceedings.[14] Unfortunately, however, the high intensity with which these debates have been conducted has not been paralleled by comparable high quality analysis. The debate in the legislative and regulatory forums has been conducted on a shallow and unfocused plane, with little serious effort at systematic problem identification and solution.[15] Futhermore, no attempt has been made to interrelate the rate design issue with the wellhead pricing controversy. Yet, if the goal is to achieve a more efficient allocation of scarce resources, the overall scheme for regulating the natural gas industry ultimately adopted must carefully interweave new wellhead pricing mechanisms with new approaches to wholesale and retail rate design.

The theses of this Article are: (1) the present method of allocating natural gas costs among consumers produces significant allocative inefficiency that has contributed to the present problems in the natural gas market and is certain to create even greater problems in the future; (2) the new rate designs suggested over the past years in regulatory and congressional debates would do little to eliminate the allocative inefficiency inherent in present rate designs and would introduce unnecessary collateral problems; (3) several approaches to the rate design issue potentially could eliminate or

12. *See, e.g.*, Trunkline LNG Co., UTIL. L. REP. (CCH) ¶ 11,970 (1977); Trunkline LNG Co., UTIL. L. REP. (CCH) ¶ 11,942 (1977); Columbia LNG Corp., UTIL. L. REP. (CCH) ¶ 11,894 (1977); Columbia LNG Corp., 96 PUB. U. REP. 3d (PUR) 389 (1972); Columbia LNG Corp., 95 PUB. U. REP. 3d (PUR) 145 (1972).

13. *See* H.R. 5289, 95th Cong., 1st Sess., § 29, 123 CONG. REC. 16,323-25 (daily ed. Oct. 4, 1977); H.R. 8444, 95th Cong., 1st Sess., § 410, 123 CONG. REC. 8309-13 (daily ed. Aug. 2, 1977); S. 2310, 94th Cong., 1st Sess., § 28, 121 CONG. REC. 33,655-59 (1975).

14. *See, e.g.*, Southern Cal. Gas Co., Cal. Pub. Util. Comm'n Dec. No. 85,627, 14 PUB. U. REP. 4th (PUR) 498 (1976); OHIO LEGISLATIVE SERVICE COMMISSION, ASPECTS OF PUBLIC UTILITY REGULATION 77-90 (June 1977).

15. There are a few recently published discussions of natural gas rate design issues that are helpful, but each analysis is incomplete, and the conclusions are too tentative to provide meaningful assistance to policymakers. In Aman and Howard, *Natural Gas and Electric Utility Rate Reform: Taxation Through Ratemaking?*, 28 HASTINGS L.J. 1085 (1977), the authors convincingly critique some recent FPC efforts to change natural gas rate designs, but they offer no alternative mechanism for dealing with the significant problems created by the present rate designs. FEDERAL POWER COMMISSION OFFICE OF ECONOMICS, INCREMENTAL PRICING OF SUPPLEMENTAL GAS (1976) recognizes the problems created by present cost allocation methods, but it suggests only broadly the possible solution of inclining block rates, without adequately discussing the problems inherent in such an approach. FEDERAL POWER COMMISSION TRANSMISSION, DISTRIBUTION AND STORAGE TECHNICAL ADVISORY TASK FORCE ON RATE DESIGN, NATIONAL GAS SURVEY (1977) [hereinafter cited as RATE DESIGN] contains excellent passages describing the problems created by the present methods of allocating costs and the theoretical economic principles that should be used to adopt new pricing approaches. The report, however, comes to no conclusion, and the use of different authors to draft separate sections of the report produces a format that is very difficult to follow.

greatly reduce allocative inefficiency at a tolerable cost; and (4) the economically preferable solution to the wellhead pricing problem follows logically from the implementation of new methods of pricing gas at the wholesale and retail levels.

## II. The Present Methods of Allocating Natural Gas Costs

Most consumers at the retail level currently receive gas under two rate forms—the declining block rate and the two-part rate.[16] The former, under which most residential and small commercial consumers are served, provides a downward tapered rate in which the first units of gas purchased by the consumer are sold at the highest price, and the last units purchased, falling in what is referred to as the "tailblock," are sold at the lowest price. The second prevalent retail rate form, the two-part rate under which many industrial and large commercial consumers receive gas, yields an analogous result.[17] The two-part rate, however, bills the customer on two bases—a demand charge based upon the amount of gas that the customer is entitled to receive under its contract, and a commodity charge based upon the amount of gas that the customer actually received during the billing period. The single most common rate form governing sales of gas on the wholesale level (sales from pipelines to distributors) is the two-part demand-commodity rate. The declining unit price characteristic of these rate forms is cost-based if the cost-averaging accounting approach traditionally used in public utility regulation is the frame of reference.

The costs that a pipeline or distributor must recover in its rates in order to earn its allowed revenues can be classified conveniently under four broad headings—customer costs, capacity costs, storage costs, and energy costs. Customer costs consist of costs that can be identified with specific classes of customers, such as billing and metering. They tend to be significantly higher relative to gas usage for small volume customers than for large volume customers.[18] Ca-

16. Rate Design, *supra* note 15, ch. 2, at 2, 10. Two-part rates and declining block rates are not the only rate forms in use today. Some pipelines and distributors use flat or volumetric rates that assign a pro rata portion of all customer and capacity costs to each unit of gas purchased. *Id.* at 4, 13. Flat rates based upon averaging of energy costs create the same potential for misallocation of resources as two-part rates and declining block rates. The extent of the misallocation of resources may be slightly less under the flat rate because the difference between marginal cost and the price of the last unit of gas purchased by a customer under a flat rate is likely to be slightly less than under a declining block or two-part rate.

17. *Id.* at 3, 10.

18. Customer costs are higher for small volume customers relative to the amount of gas consumed simply because the gas supplier must use more resources in the process of billing 100 customers for 100 units of gas than in the process of billing one customer for 100 units of gas.

pacity costs consist principally of the fixed costs of operating the system, such as the annual amortization of investment in pipes, compressors, and valves. They also tend to be much higher in relation to total usage for small volume customers than for large volume customers.[19] Storage costs, as the name implies, are the costs of storing gas in periods of slack demand for use in subsequent periods in which demand exceeds supply. Energy costs consist principally of the costs of acquiring the natural gas that the distributor or pipeline resells. As recently modified by FPC rate cases, however, the traditional *Seaboard* cost allocation method includes as much as seventy-five percent of the capacity costs in the energy cost component of the pipeline's rates.[20]

The two most common rate forms combine these four basic cost components in the following manner. In the two-part rate, capacity costs are recovered in part through the demand charge and in part through the commodity charge. The proportion allocated to each charge depends upon the particular *Seaboard* rate formula modification in use at the time. The customer cost component of a two-part rate typically is quite small because the administrative expenses of serving a large volume customer are very low relative to the volume of gas purchased. Customer costs usually are recovered through the demand charge in a two-part rate. Energy costs, as might be expected, are recovered in the commodity component of the rate. Storage costs are recovered through various accounting devices, ranging from a separate charge for each customer per unit stored for the account of that customer, to inclusion of storage costs

19. The higher proportion of capacity costs included in the rates charged small volume customers reflects that much more pipe is required for a distributor to deliver 100 units of gas to 100 small customers than to deliver the same quantity of gas to a single large customer.

20. Economists have argued for a long time that capacity costs should be borne entirely by those customers that require service during periods in which capacity is fully utilized. The theory is that only those customers are responsible for the decision to invest in the assets that comprise the system capacity costs. *See, e.g.*, J. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES 309-11 (1961); 1 A. KAHN, THE ECONOMICS OF REGULATION 89-103 (1970). The FPC rejected this theory in part and required instead that half of the capacity costs be assigned to the demand component and half to the commodity component. Atlantic Seaboard Corp., 11 F.P.C. 43, 55 (1952). While this assignment of a portion of capacity costs to the commodity charge is difficult to defend on the hasis of economic theory, it may have produced a reasonably acceptable rate structure largely because of the erroneous inclusion of some costs that vary with volume in the calculation of capacity costs.

In 1973 the Commission modified the *Seaboard* formula by requiring allocation of 75% of capacity costs to the commodity charge and 25% to the demand charge. United Gas Pipe Line Co., 50 F.P.C. 1348 (1973), *aff'd sub nom.* Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176 (D.C. Cir. 1975). The Commission questioned the applicability of the capacity responsibility theory, which supports allocation of a high proportion of capacity costs to the demand component when the gas shortage has produced a situation in which there is always suhstantial excess capacity in the pipeline system.

in the demand and commodity charges as part of system capacity costs.

In the declining block rate, customer costs typically are recovered in the first one or two blocks of the rate form. Capacity costs are recovered in most or all blocks, but commonly with a downward taper so that the tailblock includes the lowest proportion of capacity costs per unit consumed. Energy costs are recovered as a flat per unit charge in all blocks. Similar to the two-part rate, storage costs are recovered in various ways in the declining block rate. The most common method of recovery seems to include most storage costs in the capacity cost component, with aggregate capacity costs then allocated to each consumption block.

Another characteristic of present natural gas rate forms deserves emphasis at the outset. Energy costs are calculated and billed to each customer, and in each consumption block, on an average cost, or "rolled-in," basis. If, for instance, a pipeline or distributor purchases eighty-three percent of its gas supply at a cost of $0.80 per MCF[21] and the remaining seventeen percent of its gas supply at a cost of $4.50 per MCF, the energy component of the rate charged to each customer per unit purchased is approximately $1.43 per MCF.[22] This average cost method of recovering energy costs, combined with the recovery of capacity costs and customer costs in the separate demand charge component of a two-part rate or in the initial consumption blocks of a declining block rate, explains why the unit costs of purchasing gas decline for each customer as the volume of gas purchased by that customer increases during the billing period.

The costs of gas used in the above example reasonably represent the range of costs that confront interstate pipelines and distributors today. The average unit cost of gas paid by interstate pipelines in 1976 was $0.58 per MCF.[23] Gas flowing from wells drilled before January 1, 1973, and sold under long-term contracts, is limited by federal regulation to between $0.235 and $0.295 per MCF. Gas pro-

21. An MCF is 1000 cubic feet of natural gas at 14.73 pounds per square inch at atmospheric pressure and sixty degrees fahrenheit. There are two commonly used methods of measuring a unit of natural gas—volume in cuhic feet and heat content in British Thermal Units. Since the heat content of natural gas varies slightly from one supply to another, a precise translation of the two measurements is not possible without knowing the heat content of the specific supply. Because one MCF equals approximately one million British Thermal Units (1 MMBTU), this method of converting BTU's to MCF has been used throughout the Article to avoid the confusion engendered by using two different systems of measurement depending upon the source of the data.

22. (.83 x $0.80) + (.17 x $4.50) = $1.429.

23. *See* FEDERAL ENERGY ADMINISTRATION, MONTHLY ENERGY REVIEW 72 (June 1977) [hereinafter cited as MONTHLY ENERGY REVIEW].

duced from wells drilled before January 1, 1973, and sold under "renewal" contracts, is limited to \$0.52 per MCF. Gas produced from wells commenced on or after January 1, 1973, but prior to January 1, 1975, is limited to \$0.93 per MCF, while gas produced from wells commenced after January 1, 1975, can be sold for \$1.42 per MCF.[24] The price of gas sold in the unregulated intrastate market ranges generally from \$1.50 to \$2.00 per MCF.[25] Relatively little gas from so-called "nontraditional" sources flowed in 1976, but the cost of these supplies indicates the wide range of prices at which gas is potentially available at the present. For instance, liquified natural gas (LNG) imported from Algeria is estimated to cost \$5.57 per MCF;[26] synthetic gas (SNG) manufactured from petroleum products or coal costs between \$4.00 and \$5.00 per MCF;[27] and Alaskan gas transported from Prudhoe Bay is estimated to cost between \$3.30 and \$3.90 per MCF upon delivery to the lower forty-eight states.[28] Under any approach to the regulation of natural gas prices that conceivably could emerge from the political process in the near future, gas costs to pipelines ranging from \$0.23 per MCF to over \$5.00 per MCF will continue. The debate over the regulation of wellhead prices is confined to the issue whether sales of "new" gas produced from traditional sources should be deregulated or continue to be subject to federal rate regulation. Permitting rates on old gas to rise to market-clearing levels has received no serious consideration; consequently, over the next few decades a large but decreasing proportion of the total supply of gas flowing in interstate pipelines and distribution systems will be priced between \$0.23 and \$0.52 per MCF, while new supplies will be available at prices ranging from \$1.75 to well over \$5.00 per MCF.

## III. FUNCTIONAL EFFECT OF PRESENT RATE DESIGNS

Focusing for the moment solely upon the flat, average cost energy component of today's rate forms,[29] a simple example demon-

24. *See* American Pub. Gas Ass'n v. FPC, 567 F.2d 1016, 1025, 1027 (D.C. Cir. 1977).

25. MONTHLY ENERGY REVIEW, *supra* note 23, at 73.

26. Tenneco Atlantic Pipeline Co., FPC No. CP 77-100 (Nov. 2, 1977) (initial decision).

27. Transwestern Coal Gasification Co., UTIL. L. REP. (CCH) ¶ 11,669 (1975); RATE DESIGN, *supra* note 15, ch. 6, at 5.

28. RATE DESIGN, *supra* note 15, ch. 6, at 4.

29. As discussed in Part V(A) *infra*, an analysis of present rate forms cannot focus exclusively upon the energy cost component, but must consider as well the treatment of capacity costs, customer costs, and storage costs. Theoretically, it is possible for the inclusion of the sunk costs associated with the transportation and distribution of gas in the average unit cost calculation to offset the understatement of the energy cost component that results from the averaging process, yielding a unit rate that does not understate the resource cost of

strates that significant societal costs, reflected by inefficient resource allocation, are inherent in the present rate structure. If Distributor A is purchasing 100,000 MCF of old gas under long-term contracts subject to federal rate regulation at a unit cost of $0.80 per MCF, because of the much higher cost of other fuels, its customers undoubtedly will demand more gas than the distributor has available.[30] In order to meet this excess demand, the distributor may purchase 20,000 MCF of additional gas supplies in the form of liquified natural gas (LNG) imported from Algeria at a cost of $4.50 per MCF. From the distributor's vantage point, given the present rate design, the transaction is clearly economic because the rate resulting from averaging the new expensive gas supply with the old inexpensive supply is approximately $1.43 per MCF—a rate so low in relation to other sources of energy that the distributor's customers undoubtedly will continue to demand far more gas than the distributor can supply at this rate.

Is the transaction economic from society's standpoint? Is it economically rational from an overall resource allocation perspective for Distributor A to purchase 20,000 MCF of imported LNG at $4.50 per MCF in the circumstances described? Given today's methods of pricing natural gas, short of the virtually impossible task of constructing long-term demand curves for each of Distributor A's customers, no answers exist to these questions. Would Distributor A's customers choose to increase their consumption of gas by one-fifth if they were confronted with a price of $4.50 per MCF for the

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natural gas. Whether such a situation exists in a particular gas distribution system could be determined only through a detailed analysis of that system's costs and rates.

Focusing upon the energy component alone for purposes of determining the functional effect of the rate structure, however, will produce an accurate result in almost all cases for two reasons. First, to the extent that sunk costs are included in present unit rates, the effect of their inclusion on consumer behavior is minimized under either the declining block or two-part rate form because the cost of the last units of gas purchased by the consumer under either rate form includes the lowest proportion of sunk costs. Second, the prices that pipelines or distributors must pay today for additional units of gas are so high relative to the average cost of all gas flowing in a pipeline or distribution system that the vast majority of gas distributors' rates are certain to understate the costs of providing an additional unit of gas, even after adjusting the unit rate for the inclusion of sunk costs. For instance, the national average rate for gas in the first quarter of 1976 was $1.80 per MCF for residential consumers and $1.25 per MCF for industrial consumers. AMERICAN GAS ASSOCIATION, AGA QUARTERLY (First Quarter 1976). Starting with this base rate, a very significant increment of LNG or SNG could be purchased at a cost of $4.00 or $5.00 per MCF without increasing the cost of gas to the consumer to the point at which it equals or exceeds the actual cost of providing an additional unit of natural gas.

30. For instance, the cost of Number 2 fuel oil during January 1976 ranged from $2.81 to $2.99 per MCF equivalent for residential consumers and from $1.90 to $2.30 per MCF equivalent for industrial consumers. FEDERAL ENERGY ADMINISTRATION, MONTHLY ENERGY REVIEW 66-68 (April 1977).

last units they consume? If they would, they value gas at a price higher than the cost of the supply purchased by Distributor A, and Distributor A's decision to purchase the full increment of LNG maximizes consumer satisfaction and thus efficiently allocates resources. If Distributor A's customers would choose to forego the purchase and consumption of the last 20,000 MCF of gas available when forced to pay its full cost of $4.50 per MCF, then Distributor A's purchase on their behalf results in an inefficient allocation of resources. The consumers could maximize their satisfaction by placing the $90,000 spent by Distributor A to provide them with an additional 20,000 MCF of gas into the purchase of goods and services that they do value at a price in excess of the cost of making those goods available.

A response might be that consumers *may* value gas at the margin at greater than $4.50 per MCF. If that is the case, assuming that no less expensive source of supply is available, no misallocation of resources results from the hypothetical transaction described. While such an observation may be accurate with respect to this example, the potential for resource misallocation is always present in the current rate design because of the sharp disparity between the price of gas supplied under old contracts and the price at which new gas can be purchased. For instance, if Distributor A believed that its customers would continue to buy 120,000 MCF of gas at a unit price of $4.50 per MCF, it would be willing to pay up to $23 per MCF for the 20,000 MCF required to bring its total supply from 100,000 MCF to 120,000 MCF.[31] This purchase, however, would cost Distributor A's customers $370,000 in lost consumer satisfaction.[32]

The present system of allocating energy costs produces a cross-subsidization of new gas supply increments by using the gains from government regulation of the price of old gas. To the extent that we have chosen to limit the economic rent that producers can obtain for old gas produced at inframarginal costs,[33] the present system of

31. (100,000 MCF × $0.80 per MCF) + (20,000 MCF × $23 per MCF) = $540,000. $540,000 ÷ 120,000 MCF = $4.50 per MCF.

32. If consumers are willing to pay only $4.50 per MCF for additional units of gas, they can maximize their satisfaction by purchasing other commodities once the cost of gas exceeds $4.50 per MCF. By effectively forcing consumers to pay $23 per MCF for additional units of gas, the cost averaging feature of the natural gas rate structure costs consumers, in terms of lost satisfaction, $23 minus $4.50, or $18.50, for each MCF of gas purchased by the distributor in excess of the 100,000 MCF it originally had available. $18.50 per MCF × 20,000 MCF = $370,000.

33. Retaining price controls on old gas is a method of precluding producers from obtaining excessive economic rent or windfall profits on the sale of gas that can be produced at a cost substantially below the present marginal cost of producing gas. The potential for earning excessive rents from selling inframarginal cost production at prices based upon industry

wholesale and retail rate design potentially removes the entire consumer gain from consumers and transfers it to producers of new gas in the form of a subsidy for new gas supplies.[34] If pipelines and distributors respond rationally to the economic signals given to them by present rate designs, they will "spend" the entire gains from the regulation of old gas on new gas supplies, and many economically irrational projects will be undertaken.

The Council on Wage and Price Stability has estimated the magnitude of the annual subsidy made available by present rate designs to be $15 billion.[35] This approximation was derived by multiplying the quantity of old gas subject to federal rent control times the difference between the average unit cost of this gas and the estimated unit price that would clear the market for gas. In 1976 interstate pipelines purchased and resold eleven trillion cubic feet of natural gas, paying producers an average price of $0.58 per MCF. Using the relatively conservative figure of $2.00 per MCF as an estimate of the price at which the gas market would clear, the potential gain to consumers resulting from the decision to control producer rents from old inframarginal gas production is over $15 billion per year.[36] The present average-cost method of allocating commod-

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marginal cost exists to some extent in any industry and is generally tolerated as a reward to the firm with access to the most valuable factors of production, in this case large gas reservoirs discovered years ago. The potential for producers of old gas to earn excessive rents, however, is particularly high because of the extreme increase that has been experienced over the last decade in the industry marginal cost of producing gas. Thus, even if the gas production industry were structurally and behaviorally competitive, a good case could be made for retaining price controls on old gas as a method of limiting the rent that producers could otherwise obtain by selling old gas at prices based upon today's higher industry marginal cost. *See* S. BREYER & P. MACAVOY, ENERGY REGULATION BY THE FEDERAL POWER COMMISSION 64-66 (1974).

34. Of course, domestic producers of gas cannot obtain any of the potential benefits of this subsidy under the present regulatory scheme because the prices they are allowed to charge are determined by the Federal Power Commission (now Federal Energy Regulatory Commission) using a nationwide cost-of-service calculation. The potential recipients of the subsidy today are foreign gas producers, principally in Canada, Mexico, and Algeria, whose rates are not subject to United States price controls, and producers of coal and other unregulated feedstocks that can be used to manufacture synthetic gas.

35. ECONOMIC REGULATORY ADMINISTRATION OF THE DEPARTMENT OF ENERGY, WRITTEN COMMENTS OF THE COUNCIL ON WAGE AND PRICE STABILITY ON *El Paso Eastern Company* (May 8, 1978) (copy on file with the *Vanderbilt Law Review*).

36. ($2.00 per MCF - $0.58 per MCF) x 11,000,000,000 MCF = $15,620,000,000.

The method of calculation is flawed, but the result is a reasonably good approximation of the total subsidy potentially available. The formula used to calculate the amount of the subsidy should take into account the sunk costs of transportation and distribution that are included in the rates now charged for natural gas. *See* Part V(A) *infra*. Thus, the formula should be [(market clearing price of gas - present unit cost of gas paid by pipelines) x volumes of gas being delivered] - aggregate annual amount of sunk costs included in present gas rates = total annual subsidy potentially available.

The aggregate annual amount of sunk costs included in natural gas rates can be approxiity costs makes this entire $15 billion potentially available to subsidize uneconomic and irrational gas supply projects.[37] The exact amount of the subsidy made available by present rate design, of course, will vary directly with the market clearing price of gas and the quantity of old gas that continues to be available at inframarginal prices. Assuming that rent controls on new gas production are eliminated, the subsidy probably would cease to exist in the early twenty-first century, when the volume of old gas entering pipelines under long-term dedications subject to price control approaches zero. In the meantime, however, many economically irrational gas supply projects will be undertaken, resulting in substantial misallocation of resources, reducing total consumer satisfaction, and producing unnecessary inflationary pressures. Indeed, the amount of the subsidy available may increase over the next few years as the market clearing price of gas increases at a sharper rate than the rate of decline in the volumes of old gas flowing through the interstate pipeline network.

The resource misallocation potentially resulting from present rate designs will be reflected in consumption levels and in consumption patterns, as well as in irrational investment decisions. Each consumer values his last unit of gas consumption slightly lower than the preceding unit. The consumer can be expected to place the least value on the last unit of gas received (the marginal unit of consumption) because the marginal unit of consumption typically is the least expensive to forego. By pricing the marginal unit of consumption substantially below the cost of obtaining additional units of gas, the present rate design results in overconsumption of natural gas. For instance, assume that Distributor A has a customer who can forego

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mated by multiplying the annual depreciation rate allowed for rate-making purposes, 4.6%, see Texas Gas Transmission Corp., UTIL. L. REP. (CCH) ¶ 11,971 (1977), times the total investment of United States gas pipelines and distributors in transmission and distribution facilities, approximately $50 billion, see AMERICAN GAS ASSOCIATION, FUTURE FOR GAS ENERGY IN THE UNITED STATES (1977). The calculation then becomes [($2.00 per MCF - $0.58 per MCF) x 11,000,000,000 MCF] - (0.046 x $50,000,000,000) = $13,320,000,000. Of course, the amount of the available subsidy varies directly with the market clearing price of gas. If you assume, as many gas pipelines apparently do, that gas is marketable at a price of $4.50 per MCF, the amount of the available subsidy is over $40 billion annually.

37. It is unlikely that the entire amount of the subsidy potentially available actually would be spent by pipelines and distributors because this would require the timely approval by federal and state regulatory authorities of every new gas supply project proposed by gas pipelines and distributors. Since the federal and state regulatory authorities have no meaningful yardstick available to determine the economic desirability of each gas supply project and the present acute shortage of gas imposes considerable pressure on regulators to approve proposed gas supply projects, it is fair to assume, however, that a substantial portion of the potentially available subsidy will be spent through the approval of economically irrational gas supply projects.

consuming one MCF of gas at the margin by investing the equivalent of $2.00 per MCF in additional insulation. The marginal unit of gas costs Distributor A $4.50 per MCF, but the customer receiving gas under a declining block rate can obtain the last unit of gas in the tailblock of his rate form at a price approaching Distributor A's average energy cost of approximately $1.43 per MCF.[38] Faced with the true cost of consuming the last unit, the customer would forego consumption and install insulation. The present rate design masks the costs of the marginal unit of consumption, causing the customer to purchase the last unit of gas rather than to install insulation—an economically irrational choice from the standpoint of a proper allocation of society's resources and maximization of consumer satisfaction, but a perfectly rational decision on the part of the individual customer given the inaccurate pricing signals provided by the present rate design. The total amount of excess consumption that is likely to result from this understating of costs is difficult to quantify, but the wide disparity between the marginal cost of additional increments of gas supply and the price based upon average cost that each consumer pays for the marginal unit of consumption[39] suggests that the amount of excess consumption resulting from average cost pricing is substantial, even if demand for gas is relatively inelastic.

Suboptimal allocation of resources also emerges as an indirect result of present wholesale and retail rate designs. The price of a substantial portion of the total supply of gas sold at the wellhead is controlled at inframarginal prices. These inframarginal prices are averaged in with the higher prices of new supplies, producing a cost of gas to consumers that causes demand to exceed supply.[40] To return to the original example, at the $1.43 per MCF energy cost, resulting from the combination of 100,000 MCF of old gas at $0.80

38. The price at which Distributor A sells gas will exceed the distributor's average energy cost to the extent that capacity, storage, and customer costs are included in the rate applicable to the tailblock of the rate form. Of course, to the extent these costs are avoidable, they are included properly as part of the marginal cost of providing gas service.

39. As discussed in the text accompanying notes 26-28 *supra,* additional units of gas can cost a pipeline or distributor $5.00 or more per MCF. Adding the avoidable costs incurred in transporting that unit of gas to the consumer, the marginal cost of gas may exceed $6.00 per MCF. Yet, the average price paid by consumers is only $1.80 per MCF for residential consumers and $1.25 per MCF for industrial consumers. AMERICAN GAS ASSOCIATION, AGA QUARTERLY (First Quarter 1976).

40. It is theoretically possible for the gas market to clear even with averaging of energy costs. This, however, could occur only if pipelines and distributors actually spend the total annual subsidy of approximately $15 billion on economically irrational gas supply projects. As discussed in note 37 *supra,* this is not likely to happen. The cost of permitting the gas market to clear automatically while retaining the present method of determining retail and wholesale rates would be an enormous waste of resources and/or redistribution of wealth from United States consumers to foreign producers.

per MCF and 20,000 MCF of new LNG at $4.50 per MCF, Distributor A's customers will demand far in excess of 120,000 MCF of gas. Because the controlled price cannot perform the market-clearing and allocation function, an administrative method of allocating gas among competing customers is necessary. The curtailment mechanism employed by the FPC[41] undoubtedly produces an imperfect allocation of scarce gas supplies.

In a laudable effort to replicate the allocation of gas supplies that would exist given free market pricing, the FPC has based curtailments (or allocation of the gas supply shortfall) principally upon the end use to which the gas is ultimately put. Such uses as large volume boilers, which are determined administratively to be subject to a relatively elastic demand curve because the uses can be converted to alternate fuels at a relatively low cost per unit of gas displaced, are the first to lose access to gas when demand exceeds supply.[42] Uses that are determined to have relatively inelastic demand curves because they are much more expensive to convert to alternate fuels, such as residential, industrial process, and feedstock uses, receive higher curtailment priorities and are allowed access to gas during periods in which gas is unavailable to the lower priority uses.

Notwithstanding its conscious effort to maximize allocative efficiencies by using administrative mechanisms for allocating gas supplies, the FPC's curtailment rules can only crudely approximate free market results. For instance, all residential uses of gas are placed in the highest curtailment priority because the economic cost of converting a home furnace from gas to an alternate fuel is very high. The market, however, would impose some portion of the gas

41. Curtailment refers to the reduction of the quantity of gas that a pipeline or distributor must supply each of its customers below the quantity that the pipeline or distributor is required by contract to provide the customer. The FPC's authority to permit such curtailments was made clear in FPC v. Louisiana Power & Light Co., 406 U.S. 621 (1972). *See generally* NATURAL GAS HANDBOOK, *supra* note 5. *See also* Arkansas Power & Light Co. v. FPC, 517 F.2d 1223 (D.C. Cir. 1975); Louisiana v. FPC, 503 F.2d 844 (5th Cir. 1974); American Smelting & Refining Co. v. FPC, 494 F.2d 925 (D.C. Cir. 1974). The FPC's authority to permit curtailment of gas service was transferred in part to the Department of Energy and in part to the Federal Energy Regulatory Commission in the Department of Energy Organization Act, Pub. L. No. 95-91, §§ 301(a), 402(a)(1)(E), 91 Stat. 565 (1977).

42. The precise curtailment priorities vary from pipeline to pipeline, but the general scheme that has emerged in litigated curtailment proceedings places residential and small commercial requirements in the first priority, industrial process, plant protection, and feedstock requirements in the second priority, and large volume boiler fuel requirements in the lowest priority, with a residual priority containing all other requirements immediately above the priority containing large volume boiler fuel requirements. *See, e.g.*, Cities Serv. Gas Co., UTIL. L. REP. (CCH) ¶ 11,957 (1977); Transcontinental Gas Pipe Line Corp., UTIL. L. REP. (CCH) ¶ 11,865 (1976); Panhandle E. Pipe Line Co., UTIL. L. REP. (CCH) ¶ 11,779 (1976).

supply shortfall on residential uses because of the myriad actions short of conversion, such as the elimination of pilot lights and the installation of weather stripping, that the residential user can take at relatively low cost to reduce the amount of gas consumed. Moreover, classifying end uses according to degrees of demand elasticity is an overwhelmingly difficult task to accomplish in an administrative proceeding. Only broad classes of uses, such as process uses and nonprocess uses, can be distinguished.[43] The classifications cannot accurately reflect differences among the numerous types of combustion units.[44] Errors in classification are certain to occur and are unlikely to be corrected.[45] Changes in elasticity reflecting rapidly changing combustion technology may not be reflected in changed allocation priorities and reclassification of uses for decades.[46] Thus,

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43. All the end-use curtailment plans approved to date place industrial process uses in a priority superior to nonprocess industrial uses. The FPC defines a process use as "gas use for which alternate fuels are not technically feasible such as in applications requiring precise temperature controls and precise flame characteristics." 18 C.F.R. § 2.78(c)(8) (1977). The Commission has given little guidance on the meaning of this definition, but the phrase "technically feasible" necessarily must be tempered by economic considerations. Obviously, another fuel can replace natural gas for any use if the cost of replacing combustion equipment is ignored.

44. The cost of converting a combustion process from natural gas to an alternate fuel varies substantially depending upon the design and function of the combustion equipment. The cost of conversion per unit of natural gas displaced lies along a wide spectrum, yet each industrial and commercial use must be classified as process or nonprocess. Thus, the process and nonprocess priorities each necessarily include uses with widely varying costs of conversion. *See generally* J. JENSEN & T. STAUFFER, IMPLICATIONS OF NATURAL GAS CONSUMPTION PATTERNS FOR THE IMPLEMENTATION OF END-USE PRIORITY PROGRAMS (1971).

45. Because of the large number and wide variety of uses served by each pipeline, classification of uses through an adjudicatory fact-finding process is virtually impossible. Typically, the initial classification is made by the consumer, and a data committee consisting of representatives of selective pipeline distributor customers reviews the initial classification. *See* NATURAL GAS HANDBOOK, *supra* note 5, at 20-23. The potential for both inadvertent and intentional misapplication of the Commission's ambiguous definitions of end-use classifications is great.

46. Because of the gas shortage, combustion equipment manufacturers have had strong incentives to develop new methods of converting gas combustion equipment to other fuels during the last few years. As a result, many uses of gas that were properly classified as process uses in response to a questionnaire circulated in a pipeline curtailment case four or five years ago can now be converted to an alternate fuel at a relatively low cost. To reflect the availability of advances in combustion equipment conversion technology in the classification of end uses for purposes of implementing pipeline curtailment plans, however, would require an entirely new data collection effort. Moreover, some means of determining the accuracy of the new end-use data would have to be found. It may be reasonable to assume that most consumers reported their end uses as accurately as they could in response to the original questionnaires, since most consumers did not know the purpose for which the data was to be used. To make such an assumption about end-use data gathered today, long after gas consumers have learned that the classification of their end-uses in one priority or another can determine whether they will continue to receive cheap gas or be forced to substitute with more expensive fuels would be naive in the extreme. The potential for self-serving misclassifications because of a new effort to collect revised end-use data under today's conditions is extreme. In three

the resource misallocation that indirectly results from the need to substitute crude administrative allocation schemes for market price in performing the allocative function, although not precisely quantifiable, is undoubtedly substantial. Essentially, some consumers who value gas at a price greater than its replacement cost cannot obtain gas at all, while other consumers who value gas at a price less than its replacement cost are given the opportunity to purchase gas at prices substantially below its replacement cost.

The present method of averaging energy costs also raises significantly the transaction costs inherent in regulating the natural gas industry. First, the curtailment scheme that replaces the marketplace as the allocator of gas supplies has very high administrative costs. Hundreds of lawyers and expert witnesses sit in FPC hearing rooms for years debating which uses on a particular pipeline system are entitled to high curtailment priorities.[47] The major curtailment cases have been in constant litigation for five to eight years, and there is no reason to expect that the end is in sight for most cases. Indeed, since elasticities of demand change constantly with changing technology, there is no reason to expect that any administrative proceeding to allocate natural gas based upon differential elasticities of demand would ever end. Second, the present rate designs necessitate lengthy proceedings to determine administratively whether a proposed new gas supply project should be authorized. For instance, the first proceeding in which an interstate pipeline requested FPC permission to import large volumes of LNG required seven years of litigation to complete.[48] Because of the externalities

recent FERC proceedings, the Commission staff has presented testimony contending that many of the end uses initially classified as process uses on the pipeline systems at issue in those proceedings can now be converted to alternate fuels. Such contentions were presented by George D. Dornbush in Southern Natural Gas Co., No. RP 76-147; Northern Natural Gas Co., No. RP 76-52; and El Paso Natural Gas Corp., No. RP 72-6. All three cases are still in litigation and are unlikely to be concluded on a final basis for many years.

47. For instance, the curtailment proceeding initiated on the United Gas Pipeline Company system in 1970 as a result of the gas shortage is still in Phase II of what is scheduled to be a five phase proceeding. *See* Southern Natural Gas Co. v. Federal Energy Reg. Comm'n, 565 F.2d 871 (5th Cir. 1977). *See also* FPC v. Louisiana Power & Light Co., 406 U.S. 621 (1972). The curtailment proceeding initiated on the Columbia Gas Transmission Corp. system in 1971 was just remanded by a court of appeals for further hearings. *See* Elizabethtown Gas Co. v. FPC, 562 F.2d 664 (D.C. Cir. 1977). In both cases and in the multitude of other curtailment proceedings, the parties represented by counsel include most direct customers of the pipeline and many of the large gas consumers who receive gas indirectly from the pipeline through one or more distribution companies. The records typically consist of tens of thousands of pages of testimony.

48. The original application was filed September 22, 1970, and the order approving the project was issued January 21, 1977. *See* Columbia LNG Corp., UTIL. L. REP. (CCH) ¶ 11,894 (1977). Both the natural gas industry and the Comptroller General have been critical of the lengthy and costly regulatory procedures for determining whether a gas supply project should

inherent in major new gas supply projects, some form of administrative approval process will remain necessary no matter how the gas resulting from the project is priced. Reducing the time required to process applications for new gas supply projects and reducing the transaction costs of processing such applications, however, will be very difficult as long as the agency, consistent with its mandate to protect the public interest,[49] must attempt to determine whether the project is economically rational when measured by the criteria ordinarily supplied automatically by the market for the output of the project.

Since the present method of averaging the cost of new gas with old gas precludes a meaningful market test of economic rationality, the certifying agency can do its job adequately only if, before it begins the process of evaluating externalities, it attempts to determine whether the gas resulting from the proposed project would be marketable under a hypothetical rate design that reflects the full cost of the gas supply. This is an awesome task to accomplish administratively; it requires an approximation of the aggregate long-term supply and demand curves for natural gas.[50] The FPC did not

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be approved, analogizing the situation to the delay inherent in the nuclear licensing process. COMPTROLLER GENERAL, REPORT TO CONGRESS: THE NEW NATIONAL LIQUIFIED NATURAL GAS IMPORT POLICY REQUIRES FURTHER IMPROVEMENTS 14-15 (Dec. 12, 1977); *see* LNG FACT BOOK, *supra* note 3, at 30-31.

49. The responsibility of the Federal Energy Regulatory Commission in reviewing an application for a new gas supply project is to approve the project if it finds that the project is "required by the present or future public convenience and necessity." 15 U.S.C. § 717f(e) (1976). In other words, the Commission is asked to determine the societal costs and benefits of the project and to approve only those projects whose benefits to society outweigh their costs. To the extent that the societal costs and benefits of a project are internal and confronted by the party proposing the project, the Commission can rely upon the self-interest of those parties to refrain from proposing projects that are not economically beneficial to society. There are two reasons why some form of administrative determination of public convenience and necessity is required at present: (1) not all of the societal costs and henefits of a project are internalized; and (2) the rate structure under which pipelines and distributors sell gas distorts the costs and benefits of the project as perceived by its sponsor. The second problem can be eliminated by modifying the rate structure. The first will remain although air pollution regulations, safety regulations, and changes in the principles of tort law have reduced the magnitude of residual uninternalized societal costs in recent years. With a change of rate structure that forces pipelines and distributors to confront a market test of the economic viability of each project, the Commission could quite legitimately refuse to set any issue associated with a proposed gas supply project for hearing unless it involved an allegation of significant uninternalized societal costs, such as environmental degradation that the company cannot be forced to avoid by administrative regulations and cannot be forced to pay for adequately through tort law.

50. It is possible to design a computer model that would measure the economic costs and benefits of a gas supply project. Both the Federal Power Commission staff and the Department of Interior presented the results of such computer models in the form of calculations of net national economic henefits in El Paso Alas. Co., FPC No. CP 75-96, the proceeding that resulted in the approval of a gas pipeline to transport Prudhoe Bay gas to the lower

even attempt such an undertaking in the seven years in which the initial major LNG import application was being processed. If the method of allocating costs in the natural gas industry were modified in a manner that permitted a market test of new gas supply projects, the FPC's successors-in-interest, the Department of Energy and the FERC, could focus exclusively upon externalities in the project application review process, thereby permitting a substantial reduction in the amount of time and resources spent in the review of applications for new gas supply projects.

The average cost rate designs now in use generate at least one other significant societal cost. The relative bargaining strengths of the initial supplier of gas[51] and the pipeline or distributor purchasing gas for resale are seriously distorted. To illustrate the way in which average cost pricing distorts bargaining strengths, a simple hypothetical may be helpful. Suppose that a producer has a new gas supply potentially available for sale to a pipeline or distributor. Assume that the marginal cost of this supply to the producer, including cost of capital, is $2.00 per MCF. We know that the producer's marginal cost will form the basis for the unstated floor in the price negotiations between the producer and potential pipeline or distributor purchasers, but what incentive do pipelines and distributors have to bargain hard enough to bring the producer's price as close as possible to marginal cost?

The extent to which a regulated utility has incentive to shop and bargain for the lowest available price on its purchases has been a question for some time and has been particularly troublesome when, in order to achieve utility earnings stability, the purchase price of the commodity automatically is included in the utility's

48 states. A model of this variety requires calculation of the cost to consumers of the gas resulting from construction of the project and estimation of the demand for gas during the life of the project.

The economic model approach, however, has severe limitations. First, much of the time of highly trained agency personnel is required to construct the model and to determine the appropriate input data. Second, the reliability of the output of the model depends critically upon the accuracy of input data, such as long-term elasticity of demand for natural gas, that cannot be verified. As a result, there is a natural tendency for an agency charged principally with alleviating the gas shortage to select input data that will show societal benefits exceeding societal costs for all projects except those that it already has decided to reject on other grounds. It is much less likely that a company confronted with a decision to begin a project under conditions in which all of the potential costs and benefits of the project are internalized would engage in such self-deception. This may reflect a cynical attitude toward the regulatory process, but it is a cynicism resulting from years of observing expert witnesses respond to the perceived desires of their clients (whether private or public) to obtain a predetermined result.

51. From the pipeline's perspective, the initial supplier of gas may be a domestic producer, a foreign producer, a foreign government marketing agency, or a supplier of feedstock for a synthetic gas plant.

rates through devices such as purchased gas adjustment clauses.[52] When the incentive to bargain inherent in regulatory lag is removed by the purchased gas adjustment clauses, the only remaining source of bargaining incentive to the regulated pipeline or distributor is the elasticity of demand for its product.[53] If the pipeline is concerned that paying a high price for a new gas supply will increase the risk that it will be unable to sell all of the gas it is committed to purchase, the pipeline has a strong incentive to shop and bargain for the lowest price it can get. With this incentive present, the prices that producers can obtain for new gas supplies eventually should equal the long-run marginal cost of production. Although some producers may continue to earn windfall profits in the form of excessive rents on new gas supplies produced at inframarginal costs, we tolerate this potential in other industries as a reward to the particularly efficient producer.[54] The pipeline's incentive to shop and bar-

52. A purchased gas adjustment clause is a provision in a pipeline or distributor tariff that permits changes in the rate that the utility can charge for gas because of changes in the average cost that the utility must pay for its gas supply. Purchased gas adjustment clauses typically authorize dollar-for-dollar pass-through of the increased cost of gas with little delay and little, if any, regulatory review. Although they can be attacked with considerable justification on a number of grounds, purchased gas adjustment clauses probably are essential to maintain the financial viability of utilities during times of rapidly increasing costs. *See generally* SUBCOMM. ON OVERSIGHT AND INVESTIGATIONS OF THE HOUSE COMM. ON INTERSTATE AND FOREIGN COMMERCE, 94TH CONG., 1ST. SESS., REPORT ON ELECTRIC UTILITY AUTOMATIC FUEL ADJUSTMENT CLAUSES (Comm. Print 1975).

One of the effects of a purchased gas adjustment clause is to remove the effects of regulatory lag. While regulatory lag in recovering increased costs is the very evil that the purchased gas adjustment clause was designed to eliminate, it is also one of the few incentives for efficient management that the regulated company confronts. *See* 2 A. KAHN, ECONOMICS OF REGULATION 48 (1971).

53. It has been argued that the elimination of regulatory lag in recovering the costs of purchasing gas through the use of a clause leaves inadequate incentive for the utility to negotiate a hetter price or to shop for a less expensive supply. *See* R. POSNER, ECONOMIC ANALYSIS OF LAW § 12.5, at 260 (2d ed. 1977). A strong incentive for bargaining and shopping, however, can be restored through adoption of a rate structure that imposes on the utility marketahility risks corresponding to the elasticity of demand for its product. *See* 2 A. KAHN, *supra* note 52, at 102. To the extent that the demand for the utility's product is elastic, an incentive to bargain and shop is created by such a change in rate structure. Reliable estimates of the elasticity of demand for natural gas do not exist, but there seems to be general agreement that the long-term demand for natural gas is elastic. *See* BREYER & MACAVOY, *supra* note 33, at 44-54; FEDERAL ENERGY ADMINISTRATION, 1976 NATIONAL ENERGY OUTLOOK, at C-7, C-10. *See also* notes 112 & 114 *infra*.

54. Continuing to control the price at which old gas can he sold eliminates a large proportion of the excessive rents that producers might earn from selling gas produced at inframarginal cost at a price based upon marginal cost, since it eliminates the effect of temporal increases in industry marginal cost. *See* BREYER & MACAVOY, *supra* note 33, at 64-66.

A producer of new gas still may earn excessive rents from the sale of inframarginal production at a marginal cost price, however, because no two producers will confront identical marginal cost curves. The distributional implications of this residual ability to earn excess gain for the lowest price supply, however, is reduced greatly by the present rate design under which interstate pipelines and their distributor customers resell the gas that they purchase. The first hypothetical illustrated that a pipeline or distributor can purchase a new gas supply at a high unit cost and, through the cost-averaging mechanism, resell the gas at a much lower unit price while recovering all of its costs. Moreover, the availability of price-controlled old gas insures that the market will not clear automatically; demand will exceed supply at the average cost price. Thus, the pipeline or distributor faces no real marketability risk and has little incentive to shop and bargain for the lowest price supply it can obtain.

Viewed in this light, the wholesale and retail rate design issue interrelates directly with the recently "resolved" question whether to deregulate in part the gas production market. If old gas prices remain regulated, thereby controlling the amount of excessive rent that can be earned from the bulk of inframarginal production, the structure of the gas production industry and the low barriers to entry into the industry ordinarily would suggest that the market would produce acceptable results.[55] The structurally competitive nature of the gas production industry has been recognized repeatedly.[56] To the extent that significant imperfections in the market exist, they stem from two sources—the potential for unusually high

rents can be eliminated only through direct economic regulation of the price at which *each* individual gas supply can be sold or through some form of excess profits tax imposed upon each producer. The national or area ceiling approach now used to control new gas prices cannot effectively eliminate the potential for excess rents, and its continued use would ensure a continued misallocation of resources. *See* Part VI(C)(2) *infra.* This is because a national or area price ceiling imposes an effective limit on the kind of producing activity in which a producer will engage. A producer subject to a national or area rate ceiling simply will not explore for, or produce, gas with marginal costs higher than tbe generally applicable ceiling. *See* BREYER & MACAVOY, *supra* note 33, at 70. Thus, national and area ceilings on producer prices control the level of exploration activity, not the level of producer profits.

Setting maximum producer rates through individualized determinations of the cost of producing each gas well would eliminate the effect that area or national rate ceilings bave on production activity, while eliminating excessive rents resulting from the sale of inframarginal production. The FPC, however, attempted to impose individual rates based on each producer's costs in its initial effort to regulate producer prices and discovered that the task of rate regulation using an individual cost-of-service approach is administratively impossible. Its first ten proceedings required six years to complete, and by that time it had developed a backlog of 2900 applications for producer rates. *Id.* at 68. *See also* Permian Basin Area Rate Cases, 390 U.S. 747, 758 (1968). Thus, if potential excessive rents resulting from the sale of inframarginal *new* gas supplies are considered a matter of sufficient concern, the only viable approach to eliminate these rents is some form of excess profits tax analogous to that proposed in Part VI(B)(3) *infra* for gas distributors. Direct economic regulation only can perpetuate a gross misallocation of resources.

55. *See generally* BREYER & MACAVOY, *supra* note 33, at 59-64.

56. *Id.;* Southern La. Area Rate Cases, 428 F.2d 407, 416 n.10 (5th Cir. 1970); *see* Permian Basin Area Rate Cases, 390 U.S. at 756-57. *See also* Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 694-95 (1954) (Clark, J., dissenting).

rents from inframarginal production, which can be kept within reasonable bounds through continued control of old gas prices,[57] and imperfections in the process of price bargaining between producers and regulated pipelines.[58] The latter is largely a function of present wholesale and retail rate designs. The concern that producer prices for new gas may soar if new gas prices are deregulated, resulting in politically unacceptable transfers of wealth from consumers to producers, appears to be justified if the present wholesale and retail rate designs are retained. Market forces will not effectively constrain the upward movement of producer prices for new gas so long as cost averaging makes the gains from controlling the price of old inframarginal production available to the pipeline as a means of avoiding its marketability risk.[59] On the other hand, if a new rate design that provides pipelines a strong incentive to shop and bargain for the lowest price supplies available from producers can be devised and implemented, by forcing the pipeline to face realistic marketability risks, the last meritorious objection to deregulation of new gas supplies may be eliminated.[60]

The potential increase in economic efficiency and reduction in transaction costs that could be realized by substituting competition for pervasive government regnlation of the gas producing industry are very great indeed. For instance, it has been estimated that workable competition in the gas production industry would have resulted in the discovery, at prices only a few cents per MCF higher than price ceilings imposed by the FPC, of over twice as much new gas between 1961 and 1968 than was discovered under federal regulation.[61]

## IV. Recent Proposals To Adopt New Rate Designs

The recent history of efforts to define and implement new methods of apportioning costs among natural gas consumers through actions by federal regulatory agencies began with Opinion No. 622, issued by the Federal Power Commission in *Columbia LNG Corp.* on June 28, 1972.[62] In *Columbia LNG* three major inter-

57. *See* notes 33 & 54 *supra.*

58. Permian Basin Area Rate Cases, 390 U.S. at 792-94. *But see* Breyer & MacAvoy, *supra* note 33, at 61-62.

59. *See* Part II *supra.*

60. An argument still could be made in support of the need for a method of avoiding excessive rents on inframarginal new gas production. If accepted, this argument should produce some form of excess profits tax rather than direct economic regulation of the price at which new gas can be sold. *See* note 54 *supra.*

61. Breyer & MacAvoy, *supra* note 33, at 78-87.

62. Columbia LNG Corp., 95 Pub. U. Rep. 3d (PUR) 145 (1972).

state pipelines proposed to import a total of approximately 1,000,000 MCF per day of liquified natural gas from sources in Algeria for use in offsetting the overall supply-demand imbalance that had arisen on the three pipeline systems. The cost of the LNG to the pipelines was estimated initially at $0.80 per MCF,[63] and the pipelines proposed to average the cost of this new supply into their overall cost of gas, resulting in an increase in the average unit cost of gas to all customers from approximately $0.47 per MCF to approximately $0.58 per MCF.[64] The LNG then would be made available to each of the pipelines' customers in accordance with the curtailment priorities applicable to all gas sold by the pipeline.

In Opinion No. 622 the FPC approved the Columbia LNG project, but conditioned its approval upon the adoption of a method of apportioning the costs of the Algerian LNG different from the method proposed by the applicants. Describing the rate design issue as "of paramount importance," the Commission held:

> We reject the concept of rolling in relatively expensive supplemental gas supply costs with a pipeline's unit cost of gas supply. To do so would disguise the economic cost of this LNG which we find is contrary to the public interest. We, therefore, will require the filing by the purchasing jurisdictional pipelines of separate LNG rate schedules, which reflect incremental costing concepts. Thus, customers of Columbia, Consolidated, and Southern will be able to contract, if they elect to do so, under a special rate schedule, for LNG service. This special rate schedule shall reflect (a) the base import price which is certified herein, (b) the cost of service of the regasified LNG to the existing interstate pipeline, and (c) a fair allocation of cost of service of transport in the existing jurisdictional pipeline to the customer.[65]

Moreover, the FPC conditioned the certificates authorizing the pipelines to sell the separately priced imported LNG upon the willingness of each customer receiving the gas to agree to resell the gas to ultimate consumers under separate rate schedules similar to those that the pipelines were required to adopt.[66] Notwithstanding the requirement that the gas be sold under separate "incrementally-priced"[67] rate schedules, for purposes of curtailment because of gas supply shortage, the LNG would be considered a part of the total gas supply available to the pipeline system.[68] The net result would

63. *Id.* at 152.
64. *Id.* at 157-58.
65. *Id.* at 159.
66. *Id.* at 160.
67. As discussed in Part V(A) *infra*, the FPC's description of the rate design imposed in *Columbia LNG* as "incremental pricing" is a misnomer because the rates that distributors and consumers would be required to pay for the LNG would exceed incremental (or marginal) cost to the extent that sunk costs are included in the overall rate calculation.
68. *Id.* at 159.

have been that the customers and consumers who were classified in the lowest curtailment priorities could obtain gas only if they were willing to pay the incremental price of imported LNG. These customers, however, would be unable to obtain gas at any price whenever the aggregate gas supply of the pipeline, including LNG, was inadequate to provide service to the curtailment priority in which they were classified.[69]

Opinion No. 622 met opposition by virtually all parties to the proceeding. Applications for rehearing of the opinion contended that: (1) the separate pricing scheme adopted by the Commission would create an administrative nightmare;[70] (2) the FPC exceeded its jurisdiction in purporting to condition the availability of LNG to gas distributors upon the willingness of those distributors to resell the gas under a separate rate schedule;[71] (3) the combination of

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69. It is important to distinguish between the two situations in which LNG service to a customer might be curtailed. First, the service curtailment could result from an interruption in the supply of LNG itself. This risk of curtailment is unique to the particular project and certainly should be borne by the customer who is faced with the decision to commit to purchase the LNG. The second potential cause of curtailment of the LNG service is a diminution of the aggregate supply of gas from other sources that would force curtailment to the customers in priorities higher than the customer who committed to purchase the LNG unless the LNG is diverted to the higher priority customers. This is the sense in which the Commission subjected the LNG in *Columbia LNG* to curtailment, and it is the sense in which subjecting incrementally priced supplies to curtailment can destroy the financial viability of economically desirable projects. The potential for diversion of the LNG supply to higher priority consumers is not a risk associated with the LNG project; it is a risk (indeed, a certainty given the present natural gas regulatory system) associated with all *other* supplies of gas. Forcing the potential purchaser of LNG to confront both the particular risks associated with the LNG project and the general risk that aggregate demand for gas will exceed aggregate supply disassociates the costs and benefits of the project to such an extent that the decisions of consumers to commit or not to commit to participate in the project are not a reliable indicator of the project's economic societal desirability. *See* Part V(A) *infra.*

70. The use of a separate rate schedule for every new supply of gas would create a situation in which eventually each distributor's and each consumer's rates would have to be determined separately based upon the percentage of the supply received by that distributor or customer from each separately priced supply source. With distributors typically purchasing from several pipelines, which in turn purchase from other pipelines, and with each pipeline ultimately adding many new sources of gas supply, the spectre was raised of a rate case in which hundreds of individual rates must be set and applied in differing proportions to each customer. *See* Aman & Howard, *supra* note 15, at 1133-34.

This criticism of separate rate schedules for each new gas supply is well-founded. Incremental or marginal cost pricing, however, could be implemented without separate rate schedules for each new supply through other procedures, such as calculating the pipeline's marginal cost with reference to the most expensive ten percent of the pipeline's total gas supply, and then applying the resulting rate to the last 10% of supply made available by the pipeline to each of its customers. *See* Part VI(B)(1) *infra.*

71. The Hinshaw Amendment to the Natural Gas Act exempts from Federal Power Commission jurisdiction all persons who "engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas received by such person from another person within or at the boundary of a State if all the natural gas so received is

incremental pricing and rolled-in allocation under the pipeline's curtailment plan was unfair to low priority consumers and distributors that served a particularly high percentage of low priority consumers;[72] and (4) the project could not be financed with the combination of conditions imposed by the FPC.[73]

On rehearing the FPC responded with Opinion No. 622-A, issued October 5, 1972.[74] In this Opinion, the Commission retained the condition that the LNG be sold under separate incrementally priced rate schedules,[75] but it abandoned the other two conditions imposed in Opinion No. 622. Although expressly refusing to concede the jurisdictional issue, the Commission withdrew the condition that distributors could obtain the LNG only if they agreed to sell it to consumers on separate incremental cost rate schedules.[76] The Commission also stated that the LNG would not be subject to the curtailment priorities applicable to other gas supplies on the pipeline system, but would be available exclusively to the customers who committed to purchase the gas at incremental cost.[77]

With the modifications to Opinion No. 622 adopted on rehear-

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ultimately consumed within such State. . . ." 15 U.S.C. § 717(c) (1976). Thus, at least arguably, the Commission has no jurisdiction to control the rates charged by distributor customers of a pipeline for gas received from the pipeline and resold by the distributor.

The Natural Gas Act also empowers the Commission to attach "such reasonable terms and conditions as the public convenience and necessity may require" to a certificate authorizing an interstate pipeline to sell gas. 15 U.S.C. § 717f(e) (1976). This conditioning power has been interpreted expansively to permit the Commission to consider and to affect the way in which gas is sold and used after it leaves the interstate pipeline and is no longer subject to the Commission's direct jurisdiction. *See, e.g.*, FPC v. Transcontinental Gas Pipe Line Corp., 365 U.S. 1 (1961); Arizona Pub. Serv. Co. v. FPC, 483 F.2d 1275 (D.C. Cir. 1973). If the power to condition pipeline certificates were held to include imposition of conditions that directly affect distributor rate design, it is hard to find any residual meaning in the Hinshaw Amendment.

72. The Natural Gas Act makes unlawful any rate that is "unjust, unreasonable, [or] unduly discriminatory." 15 U.S.C. § 717d (1976). In two cases Commission efforts to set higher rates for industrial consumers have been rejected on grounds that the just and reasonable standard does not authorize the establishment of higher rates for industrial consumers. FPC v. Hope Natural Gas Co., 320 U.S. 591, 616 (1944); Fuels Research Council, Inc. v. FPC, 374 F.2d 842, 854 (7th Cir. 1967). The vitality of this aspect of the holdings in *Hope* and *Fuels Research*, however, is highly questionable today. *See* United Gas Pipeline Co., 50 F.P.C. 1348 (1973), *aff'd sub nom.* Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176, 1182-84 (D.C. Cir. 1975) (dictum).

Perhaps a better argument of unlawfulness can be made based upon the undue discrimination prohibition. No case authority on point exists, but it simply does not seem equitable for low priority consumers, such as industrial consumers, to receive the lowest quality gas service because of the end-use curtailment system, while simultaneously being required to pay the highest rate for that service. *See* Aman & Howard, *supra* note 15, at 1140.

73. *See* Part V(A) *infra*.

74. Columbia LNG Corp., 96 PUB. U. REP. 3d (PUR) 389 (1972).

75. *Id.* at 395.

76. *Id.*

77. *Id.* at 394.

ing, the pipeline sponsors were successful in financing the project,[78] but were so displeased with the FPC's treatment of the cost allocation issue that they filed in the United States Court of Appeals for the Fifth Circuit petitions for review of both opinions. On March 25, 1974, in *Columbia LNG Corp. v. FPC*,[79] the Fifth Circuit reversed Opinions No. 622 and No. 622-A and remanded the proceeding to the Commission for further hearings. The reversal was based upon concern that the Commission had inadequately explored the problems inherent in the new rate design. Since the method of cost allocation adopted by the Commission was a departure from prior policy and was alluded to only generally in ten pages of a 14,500 page hearing transcript, the court found that the Commission's adoption of the new method of allocating costs was not supported by substantial evidence.[80]

On remand from the Fifth Circuit's decision, the FPC held additional hearings over several months devoted almost exclusively to the rate design issue. These hearings concluded on January 21, 1977, with the issuance of Opinion No. 786.[81] In this Opinion the Commission withdrew all the rate design conditions imposed in Opinions No. 622 and No. 622-A. The approach taken in Opinion No. 622 was rejected because by subjecting low priority consumers to incremental pricing and subjecting the LNG to curtailment along with all other supplies of gas available to the pipeline, low priority consumers must commit to purchase the LNG at incremental prices without assurance that they would receive the benefits of the supply as gas shortages increased in severity.[82] Consequently, low priority consumers would be unwilling to sign long-term contracts to purchase the LNG. In the absence of executed long-term purchase contracts, lenders would be unwilling to finance supply projects subject

78. One may argue that the ability of the sponsors of the Columbia LNG project to obtain financing of that project with an incremental pricing condition demonstrates that incremental pricing will not destroy the financial viability of economically desirable gas supply projects. Two important differences exist, however, between the circumstances in which financing was obtained for the Columbia project and the circumstances in which financing for new gas supply projects must be obtained today. First, the Columbia project was financed under conditions of incremental pricing combined with an assurance of a firm noncurtailable supply *before* curtailment of so-called "firm" supplies became a matter of daily routine. Under today's circumstances, the assurance of noncurtailment would no longer be given credence by potential purchasers. *See* Part V(B) *infra*. Second, the price of the gas resulting from the Columbia project was much lower than the price at which gas from today's new supply projects must be sold. *See* Part II *supra*. Thus, the marketability risk was much lower than it would be for a comparable project today.

79. 491 F.2d 651 (5th Cir. 1974).

80. *Id.* at 654-55.

81. Columbia LNG Corp., UTIL. L. REP. (CCH) ¶ 11,894 (1977).

82. *Id.* at 14,367.

to incremental pricing.[83] The Opinion No. 622-A approach was rejected because the Commission feared that, by failing to subject the LNG supply to pipeline end-use curtailment plans, low priority consumers and their distributor suppliers could continue to receive gas through their noncurtailable contracts to purchase LNG, while high priority customers, such as residential consumers, would be unable to obtain any gas because of the continued decline in gas available from traditional sources.[84]

Thus, the Commission ultimately authorized the Columbia LNG project on the basis upon which it was originally proposed—average cost pricing and potential curtailment. In Opinion No. 786, however, the Commission warned that its action should not be considered to have precedential significance.[85] It noted specifically that it was influenced by the fact that the LNG made available through the Columbia project cost substantially less than other types of supplemental supplies under active consideration at the time and, if the cost of the LNG were averaged in with the cost of other gas supplies then available to the pipelines, it would increase the average cost of gas to the pipelines by only nine to seventeen cents per MCF.[86] During the seven years in which the Columbia LNG project was in litigation, the estimated cost of the LNG supply increased from approximately $0.80 per MCF to approximately $1.75 per MCF.[87]

While *Columbia LNG* was pending decision by the FPC after the Fifth Circuit's remand, the Commission proposed a change in its method of apportioning the energy costs of natural gas on all pipeline systems. In a notice of rulemaking issued February 20, 1975, entitled "End Use Rate Schedules,"[88] the Commission expressed great concern that although a significant and growing imbalance of supply and demand necessitated regular curtailments of service, industrial consumers of natural gas were able to purchase gas at prices substantially below the replacement cost of gas and below the cost of other fuels because of the average cost method of apportioning energy costs.[89] To remedy this situation, the Commission proposed the implementation of a new rate design that would apportion the full cost of all expensive "new" gas[90] and supplemen-

83. *Id.*
84. *Id.* at 14,370.
85. *Id.* at 14,371-72.
86. *Id.* at 14,371.
87. *Id.* at 14,369.
88. 40 Fed. Reg. 8571 (1975).
89. *Id.* at 8572.
90. "New" gas was defined as gas purchased from any source under a contract dated after December 31, 1972. *Id.*

tal gas[91] to a separate rate schedule applicable to all industrial consumers of gas. The notice did not clarify how the proposed rate design would interact with pipeline curtailment plans. With very few exceptions,[92] the hundreds of parties who responded to the Commission's notice of rulemaking attacked the proposal on grounds similar to those relied upon in attacking Opinion No. 622 in *Columbia LNG*. The rulemaking theoretically remains an active proceeding, but the FPC has taken no action in it since the initial deluge of unfavorable comments was received.

Although the Commission received adamant opposition to incremental pricing in response to Opinions No. 622 and No. 622-A and the End Use Rate Schedules proposal, and although the Commission experienced difficulties in reconciling incremental pricing with end-use curtailment, the Commission once more attempted to move to incremental pricing by attaching conditions to another proposed LNG import project. Trunkline Gas Company proposed to import 520,000 MCF per day of LNG from Algeria at an estimated cost of $3.37 per MCF. In Opinion No. 796, issued in *Trunkline LNG* on April 29, 1977,[93] the Commission conditioned the certificate approving this project upon the sale of the LNG under a separate incrementally priced rate schedule.[94] The Opinion did not clarify whether the LNG would be subject to curtailment or sold on a noncurtailable basis. State commissions with jurisdiction over distributors purchasing gas from Trunkline were encouraged, but not ordered, to require the distributors to resell the LNG to consumers under separate rate schedules at full incremental cost so that "ultimate consumers of the LNG will be charged the true cost of the LNG and will therefore be able to make truly rational consumption decisions."[95] Opinion No. 786, decided only a few months before Opinion No. 796, was distinguished on the grounds that the LNG that was the subject of that order was priced only slightly higher than the national rate applicable to new domestically produced gas supplies, while the LNG that Trunkline proposed to import cost more than twice the price permitted for new gas produced in the United States.[96]

Opinion No. 796 had a very short life. On June 30, 1977, the

91. Supplemental gas was defined to include "LNG, SNG and other synthetic gas . . . ." *Id.*

92. Of the 273 parties filing comments on the Commission's proposal, 264 opposed it. *See* Aman & Howard, *supra* note 15, at 1145.

93. Trunkline LNG Co., Util L. Rep. (CCH) ¶ 11,942 (1977).

94. *Id.* at 12,214.

95. *Id.*

96. *Id.*

Commission issued Opinion No. 796-A in response to multiple applications for rehearing filed by pipelines, distributors, consumers, and state commissions.[97] In Opinion No. 796-A the Commission once again retreated from an effort to reallocate energy costs, permitting the LNG to be imported and sold under the traditional average cost rate design method. The retreat in Opinion No. 796-A was justified on essentially the same grounds that formed the basis for Opinion No. 786—subjecting incrementally priced supplies to end-use curtailment would undermine the financial viability of the project, and permitting low priority consumers to "tie-up" LNG supplies through long-term noncurtailable contracts would leave high priority consumers without gas when production from other sources declines.[98]

The FPC has not been alone in attempting to impose new natural gas rate designs at the federal level.[99] Congress also has attempted to require variations from the present average cost method of calculating rates. In 1975 the United States Senate passed S. 2310, which included a provision designed to require the adoption of a rate design similar to that proposed in the Commission's End Use Rate Schedules rulemaking.[100] Under this provision the cost of all "new" gas and all supplemental supplies would have been imposed entirely upon industrial consumers through a separate rate schedule. The Bill would have continued to include these high cost supplies within the curtailment plans of the interstate pipelines. This proposed statutory change in rate design never became law because S. 2310 also removed "new" gas prices at the wellhead from FPC jurisdiction, and the House of Representatives was unwilling to accept such a deregulation measure.[101]

Natural gas rate design issues also were addressed in the energy legislation passed by the House and Senate in response to President Carter's proposed National Energy Plan. The compromise that the Senate and House have approved allocates most of the costs of new gas that exceed $1.42 per MCF to low priority consumers until the

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97. Trunkline LNG Co., UTIL. L. REP. (CCH) ¶ 11,970 (1977).

98. *Id.* at 12,442-43.

99. The Federal Energy Administration (FEA) has attempted to require that gas distributors who receive an allocation of petroleum product feedstocks from the FEA for use as a raw material in the manufacture of synthetic gas resell the synthetic gas on an incrementally priced basis. The FEA, however, has never explained how its version of incremental pricing would work, and a district court has held that the FEA does not have the authority to require a gas distributor to adopt incremental pricing as a condition precedent to the receipt of a petroleum product allocation from the FEA. Consumers Power Co. v. FEA, 413 F. Supp. 1024 (E.D. Mich. 1976).

100. S. 2310, 94th Cong., 1st Sess. § 28, 121 CONG. REC. 33,655, 33,658-59 (1975).

101. *See* note 7 *supra*.

rate that those consumers must pay equals the price of No. 2 fuel oil.[102] After low priority consumers reach this rate level, the FERC and state agencies are free to adopt any method of allocating costs consistent with other provisions of law.[103]

In recent years some proceedings before state regulatory agencies have concerned natural gas rate designs.[104] The goal of most state-level attempts to redesign natural gas rates, however, has been to alter the distributional effects of present rate designs, rather than to enhance the allocative efficiency lacking in the present method of allocating costs. Some version of the so-called "lifeline rate" typically is the focus of attention.[105] Whether any incidental enhancement of allocative efficiency would result from modifications of this type is not clear.[106]

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102. Natural Gas Policy Act of 1978. Pub. L. No. 95-621, §§ 201-208.

103. *Id.* § 204(d)(2).

104. *See* sources cited at note 14 *supra.*

105. The "lifeline rate" typically permits a small volume residential consumer of natural gas or electricity to purchase up to a particular quantity of gas or electricity at a rate that is set below the utility's cost-of-service in an effort to insulate poor people from some of the effects of soaring utility costs. *See generally* Aman & Howard, *supra* note 15, at 1118-21; Frank, *Lifeline Proposals and Economic Efficiency Requirements,* 99 PUB. UTIL. FORT. 11 (May 26, 1977). The rates applicable to some or all of the utility's other customers then must be increased in order to offset the revenue deficiency that would otherwise result from the noncompensatory lifeline rate. Lifeline rates of this type are unlikely to further their putative goal of income redistribution. One of the critical assumptions underlying the lifeline rate approach is that there is a strong negative correlation between wealth and amount of gas consumption. The empirical evidence at present suggests that there is no such correlation. OHIO LEGISLATIVE SERVICE COMMISSION, *supra* note 14, at 81-89; *see* Everett & Malko, *Measuring the Impact of Residential Gas and Electric Rates,* 100 PUB. UTIL. FORT. 20 (Dec. 22, 1977).

No case has been found in which a state utility commission has attempted explicitly to implement marginal cost pricing principles in setting natural gas rates. It is possible, however, that some of the more sophisticated state commissions attempt to reflect marginal cost principles in their decisions on other seemingly unrelated rate issues, without explicitly relying upon allocative efficiency as the justification for their decision. *See* Kahn, *Can an Economist Find Happiness Setting Public Utility Rates?,* 101 PUB. UTIL. FORT. 11, 14-15 (Jan. 5, 1978).

106. To the extent that lifeline rates force the rates of consumers not subject to the lifeline rate closer to marginal cost, they will increase allocative efficiency. Nevertheless, this increased allocative efficiency will be offset by a corresponding decrease in efficiency resulting from setting the lifeline rate even farther below marginal cost than a traditional average cost rate. A net increase in allocative efficiency would result only if the lifeline rate consumer's demand for gas is significantly more inelastic than the demand by the consumers whose rates are increased in order to provide the subsidized rate to low volume users. Detailed studies of relative demand elasticities would be required to determine whether the net change in allocative efficiency is positive or negative. The recent studies indicating that gas demand hy residential consumers is more elastic than gas demand by industrial consumers illustrates the danger of substituting intuition for data in making decisions that assume a particular relationship between elasticities of demand by class of consumer or level of consumption. *See* notes 112 & 114 *infra.* Of course, the distributional goals of lifeline rates may be attainahle consistent with efficiency enhancement goals through some form of marginal cost pricing,

## V. THE PROBABLE EFFECT ON ALLOCATIVE EFFICIENCY OF THE PRINCIPAL PROPOSED RATE DESIGNS

Viewed as a means of solving the problems ascribed in the beginning of this Article to the present method of apportioning costs among gas consumers, each of the proposals that has surfaced in recent debates at the FPC and in Congress falls wide of the mark and raises significant unnecessary collateral problems. For purposes of analysis, the proposals can be divided conveniently into three groups:[107] incremental pricing subject to curtailment (including Opinion No. 622, Opinion No. 796, and the 1975 Senate Bill); incremental pricing not subject to curtailment (as exemplified by Opinion No. 622-A); and incremental pricing up to the price of alternate fuels (the approach ultimately adopted in the Natural Gas Policy Act of 1978). The collateral problems raised by each kind of proposal, particularly the difficult interrelationship between rate design, end-use curtailment, and financing major gas supply projects, are serious and deserve some attention.[108] The analysis of each group of proposals, however, must begin with the recognition that none would achieve the desired goal of enhancing allocative efficiency.

### A. *Incremental Pricing Subject to Curtailment*

The basic objective of any rate design that is intended to improve allocative efficiency must be to create rates that confront each consumer with the marginal cost of the commodity or service that is available to him. The equation of price and marginal cost frequently is referred to as "[t]he central policy prescription of microeconomics."[109] Marginal cost is defined as the costs that could be avoided by producing one less unit of a good or service.[110] Its utility

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with a consumer rebate or excess profits tax that distributes tbe gains of regulation disproportionately to poor people. *See* Part VI(B)(2)-(3) *infra*. *See also* Frank, *supra* note 105, at 11.

107. There are distinct differences between some of the proposals that are included in each group, particularly with respect to the administrative prohlems raised by each. In terms of their functional effect, however, the proposals contained within a group are largely fungible.

108. The practical deficiencies of several of the proposals are discussed in some detail in Aman & Howard, *supra* note 15, at 1129-39.

109. 1 A. KAHN, *supra* note 20, at 65. *See also* J. BONBRIGHT, *supra* note 20, at 317-18; J. SUELFLOW, PUBLIC UTILITY ACCOUNTING: THEORY AND APPLICATION 245-46 (1973).

110. This is only one of many possible ways of defining marginal cost. *See* note 109 *supra*. All of the definitions, however, yield the same result when properly applied. The reference throughout this Article is te short-term, rather than long-term, marginal cost. Short-term marginal cost is the preferable pricing criterion for obtaining optimal resource allocation. 1 A. KAHN, *supra* note 20, at 70-77. There are circumstences in which considerations of administrative implementation, equity, or even efficiency require use of long-term marginal costs. This apparently is the case in the electric utility industry where use of short-

to a market-oriented economy lies in its reflecting that every decision to produce (or to purchase) an additional unit of any good is necessarily also a decision to forego the production (or purchase) of some other good. Put in the context of natural gas pricing, every consumer is faced with the choice of purchasing an additional unit of natural gas or placing comparable funds into functional substitutes such as other fuels, insulation, and more efficient appliances. The present averaging method of allocating the costs of producing natural gas, combined with the substantial quantities of gas available at regulated prices reflecting inframarginal cost, produces rates to all consumers that understate significantly the costs that could be avoided if one less unit of gas were produced.[111] Incremental pricing is a response to this problem.

Incremental pricing, properly defined and applied, is essentially identical to marginal cost pricing.[112] As implicitly defined by the FPC and Congress, however, incremental pricing does not produce the desired goal of confronting each consumer with the avoidable costs of purchasing an additional unit of gas. First, only one group of consumers, industrial consumers, is confronted with a price that purportedly is based upon marginal cost. Consequently, the other groups of consumers, residential and commercial, necessarily are confronted with a price that is less indicative of marginal cost than the average cost price that all consumers confront under present rate designs. This selective implementation of marginal cost pricing is defended on the theory that, since it is extremely expensive for residential and commercial consumers to convert to alternate fuels, whereas industrial consumers can convert at lower costs, it makes little difference if residential consumers are confronted with rates lower than marginal cost. In the language of the economist, residential and commercial consumers' demand for natural

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term marginal cost is undesirable because it is very difficult to measure and would produce rapidly fluctuating rates. *See* Madison Gas & Elec. Co., 5 PUB. U. REP. 4th (PUR) 28 (Wis. Pub. Serv. Comm'n 1974). *See also* 1 A. KAHN, *supra* note 20, at 83-86; Cudahy & Malko, *Electric Peak-Load Pricing: Madison Gas and Beyond*, 1976 WIS. L. REV. 47. The cost characteristics of the gas industry differ substantially from those of the electric utility industry. Short-term marginal cost of gas probably is easier to measure than long-term marginal cost, and because new sources of gas supply typically are flowing constantly for a very long period after they are added to a pipeline or distribution system, rates based upon the short-term marginal cost of gas would not tend to fluctuate rapidly.

In one sense the term marginal cost is not used in a manner consistent with its classic definition. To base a calculation of the marginal cost of gas upon the avoidable costs of purchasing one additional unit is not practical. Rather, some larger increment of supply should be used to reflect indivisibilities inherent in gas supply projects and to ease the administrative burden of calculating avoidable costs.

111. *See* Parts II & III *supra*.

112. *See* note 109 *supra*.

gas is assumed to be perfectly inelastic. This unstated assumption underlying the incremental pricing proposals of the FPC and Congress is at best an empirically unsupported generalization that does not withstand even a priori analysis.[113] Apparently, the reasoning is as follows: Replacement of gas burning combustion equipment or conversion to alternate fuels in a home or office costs a great deal; therefore, residential and commercial consumers have an inelastic demand for gas.

Even if the factual predicate were correct—studies of elasticity of demand for natural gas by customer class suggest that it is not—this reasoning ignores the many options open to residential and commercial consumers of natural gas in addition to total conversion to alternate fuels. For example, these consumers can reduce significantly their consumption by winterizing their homes, substituting electric ignition devices for constantly burning gas pilot lights, purchasing more efficient gas burning appliances when replacement is required, installing solar heating equipment to serve a portion of heating needs, or in some cases, simply by turning down the thermostats on their swimming pools.[114] In addition, with little or no cost penalty, potential new gas consumers can select initially an appliance that does not burn gas. Few reliable studies of elasticity of demand for natural gas exist today, but the attempts that have been made to measure demand elasticity suggest strongly that natural gas demand by residential and commercial consumers is far from perfectly inelastic. Apparently, long-term demand for gas is more elastic for residential consumers than for industrial consumers.[115] By distorting further the present disparity between residential

113. Indeed, a recent study of elasticity of demand for gas by customer classification indicates that residential demand is more elastic than industrial demand in the long term. The Federal Energy Administration has estimated that long-term elasticity of demand for natural gas is .721 for residential and commercial consumers and .392 for industrial consumers. In the short term, residential and industrial demand were found to have approximately the same elasticity, while commercial demand was found to be much more elastic than either residential or industrial demand. FEDERAL ENERGY ADMINISTRATION, 1976 NATIONAL ENERGY OUTLOOK C-7, C-10. Several other demand elasticity studies have reached similar conclusions. *See* note 115 *infra*. This attempt at gross measurement of demand elasticities by customer classification is not very helpful because each customer class encompasses numerous end uses, each of which results in a different demand elasticity. *See* RATE DESIGN, *supra* note 15, ch. 5, at 10-13.

114. *See, e.g., Investigation on the Commission's Own Motion into the Adequacy and Reliability of Energy and Fuel Requirements and Supply of Electric Public Utilities in California*, Cal. Pub. Util. Comm'n, Dec. No. 85,205 (Dec. 30, 1975) (banning new gas connections to heat swimming pools and suggesting the need for higher rates for natural gas service already being provided to heat swimming pools) (copy on file with the *Vanderbilt Law Review*).

115. The Federal Energy Administration has estimated the elasticity of demand for residential consumers as .193 in the short term and .721 in the long term. FEDERAL ENERGY

and commercial gas rates and the marginal cost of gas, the imposition of rates based upon incremental costs solely upon industrial consumers will exacerbate the present tendency of residential and commercial gas customers to engage in overconsumption.

A second characteristic of incremental pricing as proposed by the FPC ensures that its implementation would not further the allocative goals of marginal cost pricing. The industrial consumer class that, in theory, would be confronted with marginal cost under the FPC's approach actually would be asked to pay a price greater than marginal cost. The FPC's approach examines the costs of acquiring an additional MCF of gas, properly concludes that these costs are all avoidable, and therefore includes the unit cost of acquiring the most expensive gas supply in the calculation of marginal cost. The FPC, however, then simply adds the marginal cost of acquiring an additional unit of gas to the other costs of providing natural gas service, without analyzing the other components of the present natural gas rates to determine whether they consist entirely of avoidable costs. In other words, the rate designs adopted in Opinions No. 622 and No. 796, as well as in S. 2310, passed by the Senate in 1975, would require that the customers designated to pay the incremental price of a new gas supply pay a rate which reflects the marginal cost of acquiring an additional MCF of gas plus the *average cost* of transporting, storing, and distributing that unit of gas. Marginal costs, however, should not include all such costs because the fixed costs of transportation and distribution cannot be avoided by a decision not to produce or not to purchase the last unit of output. Given the present and certain future existence of excess capacity in the gas transportation and distribution industry, a high percentage of the average costs of transporting and distributing gas are sunk costs.[116] By including sunk costs in the calculation of the

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ADMINISTRATION, *supra* note 113, at C-7, C-10. This suggests that long-term demand by residential consumers is relatively elastic. Other studies have indicated much higher elasticities of demand. One commentator surveyed exhaustively the published and unpublished studies of elasticity of demand for natural gas that were conducted between 1953 and 1976. *See* Taylor, *The Demand for Energy: A Survey of Price and Income Elasticities*, in INT'L STUDIES OF THE DEMAND FOR ENERGY 3 (W. Nordhaus ed. 1977). Professor Taylor concludes that although the literature is too thin to permit reliable measurement of magnitude, elasticity of demand for natural gas in all demand categories is different from zero. *Id.* at 20. He suggests that long-term elasticity is at least 0.9. *Id.* The range of elasticities reported for the residential sector varies from 0.69 to 3.00, while the range reported for industrial demand is 0.58 to 2.11. *Id.* at 21.

116. For instance, the annual depreciation of transmission and distribution lines, estimated to be approximately $2.3 billion in note 36 *supra*, is included in present natural gas rates. These costs, however, must be considered sunk costs, since the physical life of a gas pipeline is extremely long, and no conceivable set of future circumstances could cause additional pipeline capacity to be built.

incremental rate, the FPC's method yields a rate in excess of marginal cost. Setting rates in excess of marginal cost can result in a suboptimal allocation of resources as easily as setting rates below marginal cost. The supra-marginal cost rate will induce those subject to it to purchase less of the good than they should based upon the actual costs that society must incur to make an additional unit of gas available. In this instance, the calculation upon which the industrial consumer's cost of gas would be based indicates that society must invest in a substantial network of high pressure transmission mains and low pressure distribution lines in order to provide another increment of gas to the consumer, when the entire transportation network is already in place, is only partially in use, and has very little value for any alternative use.[117]

Directionally, it is easy to see what would happen on the consumption side of the equation as a result of the FPC's incremental price formula—residential consumers would purchase more gas than they should, while industrial consumers would purchase less than they should. A simple example illustrates how this would occur. Assume that an integrated pipeline-distribution system currently is selling gas to residential consumers for $1.50 per MCF and to industrial consumers for $1.25 per MCF. This rate can be broken down into components of $0.50 per MCF energy cost for each customer (representing the average cost of gas purchased by the pipeline) and transportation and distribution costs of $1.00 per MCF for residential consumers and $0.75 per MCF for industrial consumers.[118] Assume further that the transportation and distribution costs consist of $0.25 per MCF in variable (or avoidable) costs for each class[119] and $0.75 and $0.50 per MCF in sunk costs for residential and industrial consumers, respectively. Under the FPC's incremental pricing formula, if the pipeline purchases a new supply of gas at $2.50 per MCF, the rate charged to residential consumers remains

117. It is conceivable that a few natural gas transmission lines have potential value for transporting crude oil or petroleum products. El Paso Natural Gas Company recently obtained authorization to convert one of its gas pipelines to transportation of crude oil. *See* El Paso Natural Gas Co., UTIL. L. REP. (CCH) ¶ 12,020 (1977). To the extent that such alternate uses exist for capital assets used in the transportation and distribution of natural gas, there are opportunity costs associated with the continued use of the assets that should be reflected in a calculation of the marginal cost of transporting natural gas. There is, however, no known alternate use for most of the fixed assets used in the transportation and distribution of gas.

118. Residential customers typically pay higher distribution costs because a greater investment in facilities per unit of gas delivered is required to serve a small residential customer than to serve a larger industrial customer.

119. Actually, the variable costs of distribution incurred to serve a residential customer will he greater than the variable cost of serving an industrial customer per unit of gas delivered. The same unit cost figure is used for hoth only to simplify the hypothetical.

$1.50 per MCF, $1.25 per MCF below the pipeline's marginal cost.[120] The industrial rate goes to $3.25 per MCF, $0.50 above the pipeline's marginal cost. If the residential consumer has a choice of buying an additional unit of gas or installing insulation at a cost equivalent to $2.00 per MCF, he will elect to purchase the additional unit of gas, thereby costing society $0.75 per MCF in wasted resources. If the industrial consumer has a choice of purchasing a unit of gas at a price of $3.25 per MCF or purchasing an equivalent unit of oil at a price of $3.00 per MCF, it will purchase the unit of oil, thereby costing society $0.25 per MCF in wasted resources. It is virtually impossible to calculate the aggregate waste of resources on the consumption side that result from this method of designing rates based partly on marginal cost and party on average costs, but it is safe to assume that the total unnecessary societal cost would be substantial.

The net effect of the FPC's incremental pricing system on the production side of the equation is difficult to predict even directionally because demand for gas by the residential sector would be artificially increased simultaneously with an artificial reduction in the demand for gas by the industrial sector. The interaction of end-use curtailment expectations, incremental pricing, and financing requirements for major gas supply projects, however, suggests that the net result of the FPC's rate design would be underproduction of gas.

New gas supply projects today typically are capital-intensive. For instance, the capital investment required to bring approximately 2.4 billion cubic feet of Alaskan gas per day from Prudhoe Bay is estimated to be in excess of $10 billion.[121] The investment required to import one billion cubic feet of gas per day from Algeria is estimated to be over $5 billion,[122] and a coal gasification plant capable of manufacturing 250,000 MCF of gas per day is estimated to cost $447 million.[123] Economies of scale and indivisibilities in the factors of production make smaller scale projects, which require smaller investments, impractical. For these very substantial commitments, the natural gas industry must look to external financing

120. The pipeline's marginal cost in the hypothetical is simply the new marginal cost of energy ($2.50) plus the marginal cost of transportation and distribution ($0.25).

121. The White House has estimated that the natural gas pipeline from Prudhoe Bay to the lower 48 states will cost between $10.472 billion and $13.857 billion. Executive Office of the President, *Decision and Report to Congress on the Alaska Natural Gas Transportation System* 157 (1977).

122. Tenneco Atlantic Pipeline Co., FPC No. CP 77-100 (Nov. 2, 1977) (initial decision).

123. Transwestern Coal Gasification Co., UTIL. L. REP. (CCH) ¶ 11,669, at 12,998 (1975).

sources, principally institutional investors. Investors generally, and institutional investors in particular, look for low risk investments, and when investing hundreds of millions, or billions, of dollars in a single project, institutional investors can be expected to examine very carefully the risks inherent in the investment. One major risk in a gas supply project is that at some point the gas will not be marketable. This risk is largely eliminated under the present average cost rate design employed in the natural gas industry, since the large volumes of old gas flowing into a pipeline system provide a large cushion that permits the purchase of a new supply at a high unit cost without a corresponding increase in cost to consumers. Thus, given adequate tariff provisions,[124] investors are willing to place large sums of money at risk in gas supply projects when the new gas is permitted to be sold on an average cost basis.

When the gas must be sold under a separate incremental rate schedule to low priority consumers, the investment community, in effect, is being asked to project the supply and demand for natural gas over the life of the project, typically twenty to thirty years. This entails guesswork concerning domestic political and regulatory decisions and world political and economic conditions.[125] The investment community understandably is overawed by the task and seeks some substitute for this difficult and hazardous long-term forecasting. It reasons that if low priority consumers or their suppliers are willing to sign long-term purchase contracts obligating themselves to take or pay for the aggregate output of the gas supply project under an incremental pricing schedule, its capital return is reasonably assured; otherwise, it perceives the marketability risks as being too great. In short, the investors turn to the low priority consumers to perform the task of forecasting future supply and demand by requiring the consumers to bear the risk that future conditions will

124. In addition to the issue whether the output of a new gas supply project will be priced on a rolled-in or incrementally priced basis, there are a number of other price-related provisions of the certificate authorizing a major new gas supply project that can adversely effect its financial viability. *See, e.g.*, Trunkline LNG Co., UTIL. L. REP. (CCH) ¶ 11,970, at 12,443-45 (1977). Of course, these complications would be removed if the price of new gas supplies from all sources were deregulated, as suggested in Part VI(C)(3) *infra*. With an unregulated rate of return, investors should be much more willing to assume the risks inherent in a proposed gas supply project. If insufficient capital can be attracted to the project with an unregulated rate of return, it is fair to draw the inference that the project is not economically desirable.

125. The long-term aggregate supply and demand for natural gas can be affected significantly by a myriad of factors, many of which are difficult to forecast. They include actions of the United States government, such as decisions to permit or forbid development of hydrocarbons on the outer continental shelf, and international developments, such as decisions by Saudi Arabia to reduce or accelerate the rate at which it produces crude oil.

make the gas output of the project appear less attractive than alternate means of meeting energy requirements. So far, the description of the financial community's reaction to the perceived marketability risk is entirely rational and consistent with a theoretical model for determining when society's resources should be committed to a long-term investment in an uncertain market environment.[126] At this point, however, theory departs from fact in two significant respects.

First, as discussed in Part IV, the low priority consumer is not asked to commit to purchase the gas at marginal cost. These consumers are offered the supply at a price that exceeds the marginal cost by the amount that the incremental rate, calculated using the FPC's formula, requires low priority consumers to bear a portion of the sunk costs of transporting and distributing gas. Second, the major potential benefit of committing to purchase the supply under a long-term contract—assurance of continuity of supply—is removed from consideration because of the "curtailable" nature of the supply. The low priority consumer knows that it will have access to the gas from the proposed project, even at a price in excess of marginal cost, only as long as gas supplies from other sources are adequate to meet high priority demand. With gas supplies from other sources dwindling rapidly and excess demand from high priority consumers predictable because of the subsidized rates applicable to high priority consumers under the FPC's version of incremental pricing, the industrial consumer can predict with certainty that it will not have access to the incrementally priced gas during shortage periods when it most values the gas. An industrial consumer also will be required to pay a price in excess of marginal cost during periods of temporary market equilibrium when it does not need the gas.[127] In the inelegant but accurate words of one witness who was

126. Investors necessarily confront a great many risks in putting money into any project, and the likelihood of occurrence of many of these risks is subject to a high degree of uncertainty. Because the capital available for investment is limited, to select the projects which will go forward, someone must decide which projects offer the most attractive combination of potential costs and benefits, taking into account the probability that each risk will or will not occur. The "someone" could be either a government agency or private investor. Although we have chosen to permit the government to exercise some degree of indirect control over investment decisions, we generally have chosen to permit private investors to decide how society's limited capital should be allocated among competing projects. The assumption is that because the private investor's profits and losses depend upon the accuracy of his forecasts of costs and benefits, he has the greatest incentive to make accurate forecasts as a predicate to his investment decisions. Of course, the extent to which this practice allocates scarce capital to the projects that are most beneficial to society depends upon the extent to which the societal costs and benefits associated with each project are internalized to the investor. *See* Part VI(C)(3) *infra*.

127. No matter how certain the prospect for a gas shortage in the long term, there

asked to react to the choice presented by an incrementally priced, take-or-pay-for contract subject to curtailment, a customer "would have to be a sucker to buy it."[128]

Of course, this explains only why low priority consumers and their distributor suppliers would be unwilling to commit to purchase a new gas supply subject to incremental pricing and curtailment. The question might be asked: Cannot the financial community obtain the marketability assurances it requires through long-term purchase commitments by distributors who serve principally high priority consumers? These parties would not share the low priority consumer's fear of diversion of gas to other consumers, and most major new gas supply projects are supported with projections of supply and demand that indicate that substantial service curtailment to residential and commercial uses of natural gas will exist in the early to mid-1980's unless the project is authorized.[129] Because the gas obtained from the project is subject to diversion through the operation of a pipeline curtailment plan, the distributor has no incentive to commit to purchase the supply for the benefit of its high priority customers. If the distributor commits to purchase the supply under an incrementally priced, take-or-pay-for contract, it is obligated to buy gas under the contract despite the varying conditions of supply and demand that will exist over the typical twenty-year contract period. This undoubtedly will encompass periods in which the distributor's residential customers would be curtailed if the new supply were not developed, and periods in which the distributor is unable to market the gas to anyone at its incremental price.[130] Thus, committing to a long-term purchase contract for an incrementally priced supply creates significant marketability risks for the distributor. These risks can be avoided by not committing to purchase the supply and letting other distributors take the marketability risk. The distributor can rely upon the curtailment mechanisms to provide enough gas from other distributors who do make long-term commitments to permit it to meet its high priority requirements during the periods in which the distributor's supply of low-priced pipeline gas is insufficient to meet its high priority re-

always will be periods in which supply temporarily exceeds demand. The demand for gas fluctuates dramatically even in the short run because of changes in temperature, but the supply cannot vary in such an erratic manner hecause of limited storage facilities and technical limitations on temporary cessation of gas production at the wellhead.

128. Tenneco Atlantic Pipeline Co., FPC No. CP 77-100, at 808.

129. *See, e.g.,* Trunkline LNG Co., UTIL. L. REP. ¶ 11,970, at 12,422-23 (forecasting 25% curtailment of residential uses on the Trunkline system by the mid-1980's, even if LNG imports are approved).

130. *See* note 127 *supra.*

quirements. In other words, the combination of incremental pricing and diversion through the curtailment mechanism creates a classic "free rider" situation—high priority consumers and their suppliers believe that they can obtain all the benefits resulting from the development of an expensive new gas supply without assuming any of the risks inherent in a long-term commitment to purchase the supply, while low priority consumers and their distributor suppliers are reluctant to commit to long-term purchase contracts because of the likelihood that the free riders will obtain most of the benefits of their purchase commitment.

The net result of the disassociation of risks, costs, and benefits that occurs under incremental pricing subject to curtailment is that no class of consumers or distributors is willing to make long-term purchase commitments for gas obtained from a new supply project, even if each class of consumer and distributor concludes that a long-term commitment to purchase a portion of the output of the project would be in its best interest absent governmental intervention through the curtailment mechanism. Thus, the contention of gas pipelines and distributors that incremental pricing of supplemental supplies subject to curtailment would destroy the financial viability of both good and bad gas supply projects is credible.

### B. *Incremental Pricing Not Subject to Curtailment*

To a point the rate design-curtailment mechanism adopted in Opinion No. 622-A should produce results analogous to those anticipated from Opinions No. 622 and No. 796. Selective incremental pricing combined with an assurance that gas purchased under long-term supply contracts will not be diverted to others through the curtailment mechanism should have allocative effects on the consumption side almost identical to incremental pricing subject to curtailment. To the extent that high priority consumers are permitted unlimited access to gas at prices significantly below marginal cost, they will engage in overconsumption, assuming that their demand for gas is not perfectly inelastic.[131] To the extent that low priority consumers are permitted to purchase gas only at a price in excess of marginal cost (through the inclusion of sunk costs in the FPC's erroneous calculation of incremental price), they will consume less natural gas and more of other commodities than is economically optimal. As in the case of incremental pricing subject to curtailment, it is impossible to determine whether allocative effi-

131. As discussed in notes 112 & 114 *supra*, elasticity studies indicate that residential demand for natural gas is not inelastic in the long term. It, however, appears to be more elastic than industrial and commercial demand.

ciency on the consumption side will be enhanced or reduced because of this change in rate design from the present average cost rate design, but it is clear that resources still will be suboptimally allocated.

Theoretically, the tying of risks to benefits through the assurance that gas purchased under separate incrementally priced rate schedules will not be diverted should decrease or eliminate the tendency of incremental pricing to destroy the financial viability of economically desirable gas supply projects. Assuming that the method of calculating incremental price were modified to eliminate the inclusion of sunk costs, a consumer could evaluate the cost of the supply, the risks unique to the particular supply, and the benefits of obtaining access to a relatively secure long-term supply source, and then make its decision to purchase or not to purchase the supply based upon its assessment of the costs, risks, and benefits of this supply versus all alternative means of accommodating its long-term requirements for fuel. If enough consumers (and/or their distributor-suppliers) committed to purchase the gas under long-term contracts, the financial community would be willing to put its funds at risk, and the project would have passed a valid market test of its economic viability. If no consumers or distributors were willing to commit to purchase the supply under these conditions, the financial community would be unwilling to invest in the project, but this would indicate merely that the project is not economically desirable because consumers found that the combination of costs, risks, and benefits associated with alternate means of meeting their needs were more attractive. Thus, in theory incremental pricing not subject to curtailment would improve allocative efficiency on the production and investment side.

The validity of this theoretical method of reintroducing rational resource allocation on the production side of the gas industry depends on the accuracy of two critical assumptions. First, the theory would operate in the desired manner only if the incremental price at which the gas could be purchased were calculated correctly, without inclusion of sunk costs. Since any regulatory agency presumably is capable of distinguishing between sunk costs and variable or avoidable costs, it is reasonable to assume that the calculation of incremental price would be performed correctly once the error in the FPC's initial method of calculation was identified. The second assumption is more troublesome. The theory would work properly only if the assurance that the supply would not be subject to diversion through curtailment were credible to the consumers and distributors who must make the decision to commit or not to commit to purchase the supply. If the potential purchasers do not find the regulatory agency's assurance of noncurtailment credible, the disassociation of risks and benefits that results in the conclusion that incremental pricing subject to curtailment would undermine the financial viability of economically desirable projects returns.

For the FPC or any other regulatory agency to give a credible assurance that any gas supply purchased today would not be subject to future diversion to benefit higher priority consumers would be very difficult, and applying incremental pricing only to low priority consumers would virtually assure future direct governmental interdiction of supplies. Curtailment of gas supplies, including curtailment of gas purchased under contracts that prohibit curtailment, has become a routine event in the gas industry.[132] The Federal Power Commission and its successor have the power to require curtailment of gas service, notwithstanding provisions in contracts forbidding curtailment, in order to insure that high priority consumers do not experience supply interruptions.[133] Even if the FPC were willing to give assurances that it would not divert gas supplies purchased under incremental rate schedules,[134] it could not bind future commissions by giving such an assurance. As the Commission recognized in Opinion No. 796-A:

> In a related matter, the Commission agrees that it cannot in this proceeding, ensure that future commissions or successor regulatory authorities, would never curtail the gas sold under separate incremental rate schedules. We also agree that the eventual curtailment of this LNG supply, under purportedly "non-curtailable" rate schedules, has been a major factor in the apparent reluctance of parties to sign 20-year contracts with take-or-pay provisions for the purchase of LNG.[135]

Thus it is apparent that as long as potential purchasers believe that high priority consumers will require access to incrementally priced supplemental supplies of gas in order to avoid future service interruptions, no regulatory agency can provide credible assurances that gas purchased under separate incremental rate schedules will not be diverted.

The potential for future diversion of supplies is important only

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132. Curtailments of "firm" service have increased every year since 1970. NATURAL GAS HANDBOOK, *supra* note 5, at 3. In 1976-77, curtailments of "firm" service occurred on 31 interstate pipeline systems, with aggregate curtailment amounting to 23% of total "firm" requirements. FEDERAL POWER COMMISSION, *supra* note 5.

133. FPC v. Louisiana Power & Light Co., 406 U.S. at 646-47.

134. At least since its 1972 decision in Columbia LNG Corp., 96 PUB. U. REP. 3d (PUR) 389, the Commission has heen unwilling to assure that a gas supply will be available on a firm, noncurtailable basis. *See, e.g.*, Columbia LNG Corp., UTIL. L. REP. ¶ 11,894, at 14,370.

135. Trunkline LNG Corp., UTIL. L. REP. ¶ 11,970, at 12,443.

if the demand for gas for high priority uses will exceed the supply of gas that is not subject to the long-term incrementally priced contracts. If future supply shortfalls will be infrequent or nonexistent, the theoretical risk of diversion will not weigh heavily in the decisions of potential purchasers. To determine the extent to which the theoretical potential for diversion should be considered a realistic risk, one must return to the manner in which selective incremental pricing would affect decisions at the point of consumption. Because high priority consumers would be provided access to gas at a price substantially less than marginal cost under even a properly calculated selective incremental pricing system, the demand for gas by such consumers would increase over time. With incremental additions to total gas supply tied up under long-term, noncurtailable contracts and the volume of old gas flowing from traditional inframarginal sources continuing its inevitable decline, regulatory agencies soon would face again the choice of permitting service interruptions to high priority consumers or diverting gas purchased under noncurtailable contracts. The outcome of that decision, at least in our political system, always is going to be the same. Thus, when political realism and the operation of the rate design at the point of consumption are interjected into the analysis, a system of selective incremental pricing with no curtailment becomes, on analysis, identical in actual impact to a system of selective incremental pricing subject to curtailment.

### C. *Incremental Pricing up to the Price of Alternate Fuels*

The Natural Gas Policy Act of 1978 requires interstate pipelines to allocate most costs of acquiring gas that exceed $1.42 per MCF exclusively to low priority consumers and to distributors that serve low priority consumers.[136] This basic formula, however, operates only to the point at which the price that the low priority consumer must pay for gas equals the price of No. 2 fuel oil.[137] Presumably, once this ceiling is reached, the pipeline and/or regulatory agency is free to return to the traditional average cost method of allocating energy costs.[138] To determine the origin and putative purpose of this proposed method of apportioning costs through rate design is difficult. Because this approach would provide no meaningful potential for enhanced allocative efficiency and only a temporary and modest distributional impact among gas consumers and distributors, the

136. Pub. L. No. 95-621, §§ 201-208.
137. *Id.* § 204(c)(3)(B).
138. *Id.* § 204(d)(2).

best guess is that it is simply an unprincipled but expedient compromise between advocates of retention of average cost pricing and advocates of incremental pricing.

In the short term this compromise approach to the rate design issue would produce consumption patterns similar to an approach using incremental pricing subject to curtailment. High priority consumers, faced with rates even farther below marginal cost than rates calculated using average cost methods, would consume more gas than they should. Low priority consumers confronting, at least temporarily, rates in excess of marginal cost[139] would consume less gas and more substitutes than they should. In addition, in the short term, distributors and the state commissions that regulate them probably would engage in a series of rapid, ad hoc efforts to reallocate distributor fixed costs among classes of consumers in order to minimize the total cost of obtaining gas that the distribution system and/or the state must pay the interstate pipelines. Any distributor serving at least one low priority consumer could escape the burden of paying a disproportionately high price for the gas purchased from a pipeline to serve that consumer as soon as the low priority consumer's rate for gas equals or exceeds the price of alternate fuels. Consequently, the distributor and the state commission regulating the distributor would have a clear common interest in taking actions that would cause the rate of the low priority consumer to reach the price of substitute fuels as rapidly as possible. This could be accomplished easily by redesigning the distributor's rates to ensure that all low priority consumers pay a rate equal to the price of alternate fuels regardless of the price that the distributor must pay for pipeline gas to serve the consumer—by imposing a disproportionate share of the fixed or joint costs of distribution on the low priority consumer.

The period of time in which low priority consumers face a rate at least equal to marginal cost under this method of allocating costs will be very short indeed. Given the price at which new gas supplies can be obtained today,[140] the inclusion of sunk costs in the rates of low priority consumers,[141] and the price of No. 2 fuel oil, all low priority consumers soon will be paying a rate equal to the price of

139. The rates applicable to low priority consumers can exceed marginal cost because the rates of low priority consumers under the bills would consist of the marginal cost of gas at the point of initial acquisition, plus the average cost of transporting and distributing gas. *See* Part V(A) *supra.*

140. The prices for new gas range from $1.75 to over $5.00 per MCF. *See* text accompanying notes 25-28 *supra.*

141. *See* Part V(A) *supra.*

alternative fuels.[142] At this point the ceiling in the statutory provision will be triggered and the pipelines, distributors, and regulatory agencies are free to return to average-cost pricing. All that will be accomplished is a slight acceleration of the present trend of gas rates for low priority consumers to equal or exceed the price of alternative fuels.[143] Because demand by most natural gas consumers is almost perfectly inelastic up to (and somewhat above) the price of alternative fuels,[144] no long-term changes in allocative efficiency on the consumption side can be anticipated. The return to average cost pricing once the statutory ceiling on incremental pricing is reached also would eliminate any potential for enhancing allocative efficiency in decisions to develop new gas supply projects, would leave the bargaining powers of pipelines and producers seriously skewed, and would eliminate any potential for permitting market forces to replace administrative allocation in clearing the natural gas market. In short, the modifications in natural gas rate design mandated in the Natural Gas Policy Act of 1978 will produce exactly the same set of problems that are inherent in the present rate design. Further changes in rate designs are essential to bring health back to the chronically ill natural gas market.

## VI. Promising Approaches to the Problem

Conceptually, the cure for the seriously maladjusted natural gas market is easy to state. The pricing system must confront each consumer with the marginal cost of natural gas service and must replace the curtailment mechanism by clearing the gas market automatically. Such a pricing system would assure efficient allocation of resources on both the production and consumption sides, eliminate the high transaction costs and rigidities associated with administering curtailments, provide strong incentives for pipelines and distributors to bargain for the lowest price supply that they can obtain, and permit a reduction in the delay and transaction costs inherent in the present method of government review of proposed new gas supply projects.

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142. The range of prices that industrial consumers paid for fuel oil in January 1976 was \$1.90 to \$2.30 per MCF equivalent. Federal Energy Administration, *supra* note 23, at 68.

143. The rates applicable to industrial consumers of natural gas have been projected to exceed the price of fuel oil in two regions by 1981 and in all regions by 1985 if present rate designs are retained. LNG Fact Book, *supra* note 5, at 29.

144. Natural gas is a perfect substitute for oil in almost all applications, and its precise flame geometry and clean burning characteristics cause consumers who can burn either natural gas or oil to prefer natural gas. The amount of the premium a consumer will pay to use natural gas rather than oil depends upon the consumer's circumstances, particularly the way in which the gas will be used.

The adoption of a "pure" marginal cost pricing system[145] in the natural gas industry, however, is inconsistent with two other goals of the regulatory process. First, implicit in the present system for regulating producer prices is the goal of limiting the excess rents that could be obtained through production of old gas at inframarginal costs and its sale at prices based upon marginal cost.[146] The retention of price controls on most old gas in the producer pricing provisions of the Natural Gas Policy Act of 1978 indicates that this goal is likely to be an enduring one. The adoption of full marginal cost pricing at the producer sale level is inconsistent with this goal. Second, because natural gas pipelines and distributors share many of the characteristics of a classic natural monopoly, a major goal of the regulatory system is to limit the revenues that can be earned by these companies. Since it appears that this goal is unlikely to be abandoned in the near future, full marginal cost pricing cannot be effectuated at the wholesale or retail level except in the wholly fortuitous (and presently rare) situation in which the pipeline or distributor's marginal cost equals its average cost.[147] In the typical case, marginal cost exceeds average cost, and adoption of pure marginal cost pricing at the wholesale or retail level will result in revenues to the pipeline or distributor that exceed those that society desires to allow.[148]

At least three possible methods of structuring natural gas rates can accommodate the constraints of limiting pipeline and distributor monopoly profits and limiting producer rents on inframarginal production, and simultaneously eliminate or greatly reduce the problems inherent in the present methods of interrelating costs and

145. Pure marginal cost pricing refers to the setting of all rates for natural gas at marginal cost.

146. *See* note 33 *supra*.

147. Of course, when marginal cost equals average cost, it is relatively easy to switch to marginal cost pricing because this can be accomplished by reallocating costs from one class of consumers to another without worrying about methods of accommodating the revenue constraint.

148. Average cost possibly could exceed marginal cost in a few isolated areas today. *See* RATE DESIGN, *supra* note 15, ch. 10 § 5, at 2 (suggesting that gas rates in New England exceed marginal cost). Where this is the case, adoption of marginal cost pricing, through the process of establishing maximum rates based upon marginal cost, would reduce the rate of return earned by the distributor or pipeline below the rate that would otherwise be permitted. In this situation mandatory marginal cost pricing should be imposed only if it is accompanied by a subsidy to the regulated company that offsets the earnings deficit. Failure to permit investors to earn a rate of return on investments that have become sunk costs of the enterprise will deter future investments in the fixed assets of an industry subject to direct economic regulation. *See* D. BOIES & P. VERKUIL, PUBLIC CONTROL OF BUSINESS 419-20 (1977). Of course, *requiring* a company to charge a rate in excess of marginal cost through the use of minimum rates raises quite different considerations.

prices. For convenience these methods will be referred to as inclining block rates, marginal cost pricing with consumer rebates, and marginal cost pricing with an excess profits tax. Each of these methods presents both problems of implementation unique to it and problems shared with the other two possible methods. None of the problems, however, is insurmountable, and the adoption of any of the three methods could improve the operation of the natural gas market, while establishing conditions in which the wellhead rate for new gas could be deregulated without siguificant risk of undesirable transfers of wealth from consumers to producers.

Because each of these three viable approaches to the natural gas pricing problem relies heavily upon an accurate calculation of marginal cost, the following discussion begins with a broad conceptual method of identifying marginal costs and assigning those costs to the appropriate consumer or class of consumers. This will be followed by a description of each of the three methods of employing marginal costs in natural gas pricing, the problems unique to each, and potential means of eliminating or reducing those problems. Finally, problems potentially shared by all three methods of integrating marginal cost into the rate structure will be identified and discussed.

### A. *Identifying and Assigning the Marginal Costs of Natural Gas Service*

Marginal costs are simply those avoidable costs that are incurred in order to provide one more unit of a good or service.[149] Thus, each major element of cost that goes into the calculation of natural gas rates must be analyzed to determine whether it should be included in the marginal cost calculation, and, if so, whether it is a cost common to all consumers or unique to a particular group of consumers.

The first major element is the cost of purchasing the gas from a producer, importer, or manufacturer.[150] This clearly is an avoida-

149. Because of indivisibilities in the factors of production and the need to adopt methods of calculating rates that are relatively easy to implement administratively, marginal cost, in the strict sense of the avoidable costs of producing one more unit, makes little sense as a rate standard. Rather, an easily calculated approximation of marginal cost should be used. One sensible approach that would implement marginal cost pricing principles without introducing unnecessary complications into the rate-setting process would he to use as a surrogate for marginal energy cost the average cost of the most expensive 10% of the pipeline or distributor's total gas supply. The dilution of marginal cost pricing resulting from the use of such a surrogate would be slight, and the reduction in transaction costs would be significant.

150. Because of the OPEC cartel, the marginal cost of producing natural gas may differ significantly from the pipeline's marginal cost of acquiring natural gas in the form of imported

ble cost and should be included fully in the calculation of the marginal cost of serving each consumer. But for each consumer's purchase of gas, the pipeline or distributor could avoid incurring the cost of purchasing the last unit of gas.

Determining the appropriate classification of the myriad costs that previously have gone under the broad heading of capacity costs in the traditional *Seaboard* formula for establishing two-part rates requires identification of the principal components of capacity costs and analysis of each. The first major component of capacity costs is the cost of the equipment such as pipes and valves through which gas is transported and distributed. With one significant exception, these costs should not be included in the calculation of marginal cost. The conditions that justified the use of the two-part rate with a separate charge for capacity costs based upon responsibility for peak-period capacity no longer exist, at least for the vast bulk of the physical plant investment required to transport and distribute gas.[151] The gas pipeline and distribution industry, like the railroad

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LNG. For instance, the marginal cost of producing natural gas in Algeria may be as low as $0.25 per MCF, but Algeria's market power from its membership in a price-fixing cartel may permit it to charge in excess of $1.00 per MCF for its gas production (ignoring the very high costs of cryogenic processing and transportation). Because the United States has no control over this overstating of marginal resource cost, the relevant marginal cost for rate-making purposes should be the marginal cost to the pipeline of acquiring the gas—this also represents the marginal cost to the United States economy. *See* Kahn, *The Economics of Regulation: Externalities and Institutional Issues,* 101 PUB. UTIL. FORT. 23, 24 (Feb. 2, 1978).

151. The basic justification for the two-part rate is that consumers whose demand for a product or service at a time when the fixed assets required to produce that product or service are fully utilized should be required to pay the capacity costs. If the consumers who are responsible for the industry's capacity are not required to pay a rate that reflects the cost of that capacity, more consumers will demand the product or service during the period in which the present capacity is fully utilized. This, in turn, will result in expansion of the industry's capacity, but the need for capacity expansion will have resulted from increased demand induced by a price that does not reflect the costs of present capacity, much less the cost of an expansion in capacity. *See generally* 1 A. KAHN, *supra* note 20, at 87-122; R. POSNER, *supra* note 53, § 12.5.

For most of the fixed assets required to transport and distribute natural gas, just as for some of the fixed assets of the railroads (mainly roadbed), there is no realistic danger that failure to reflect capacity costs in rates will result in a false price signal to consumers that in turn, will result in unjustified investment in increased capacity. This is because there is substantial excess capacity in both the gas transportation and distribution industry and in the railroad industry, and there is no foreseeable set of future circumstances in which the capacity of either industry will be fully utilized. Thus, the capacity costs of transporting and distributing gas should be considered sunk costs and should not be reflected in individual consumers' rates. Exclusion of sunk capacity costs from the calculation of unit rates will have the salutory effect of encouraging maximum utilization of existing capacity. *See* R. POSNER, *supra* note 53, § 12.5, at 262-63; Kahn, *supra* note 105, at 12-13.

This is not to say that the regulated company should not be allowed to recover its sunk costs if market conditions permit it to do so. *See* note 148 *supra*. Under present conditions in the natural gas industry, the rate to consumers can be based upon marginal cost, excluding industry, is now typified by substantial and chronic excess capacity. The physical plant is unlikely to require expansion even in the long term, and it has little if any value for purposes other than transporting natural gas.[152] Consequently, it should be treated as a sunk cost or a free good in calculating the marginal cost of providing gas service. The significant exception to the exclusion of physical plant costs from the calculation of marginal costs is when the investment obviously is not a sunk cost, as when the pipeline or distributor installs new pipe. Given chronic excess capacity, this is most likely to happen in one of two circumstances: (1) when new pipe is installed in order to attach a new supply, or (2) when new pipe is required to serve new customers. In the first instance, the costs of the physical plant should be included as a component of the marginal cost of the new supply. In the second case, the costs should be included in the calculation of the marginal cost of serving the new customers. To avoid the appearance of inequity in the rate structure and the complexity of many different rates for consumers with similar consumption characteristics, the second class of new physical plant costs should be recovered through the imposition of a one-time connection charge,[153] rather than through the unit rate charged to the new customer.

Capacity costs traditionally have included some variable costs as well as fixed costs of physical plant. An obvious example is the fuel required to transport gas through a pipeline or distribution system. The marginal cost calculation should encompass all such avoidable costs, even those previously included under the label capacity costs.

Costs such as billing and metering, which traditionally have been referred to as customer costs in gas distributor ratemaking, are almost entirely avoidable and should be included in the calculation of the marginal cost of serving each class of customer. Since these costs vary depending upon the characteristics of the customer, but do not vary directly with the volume of gas used by a particular customer, they should be recovered through a separate charge on each customer's bill reflecting the administrative costs of serving that class of customer.

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the sunk costs of transportation and distribution capacity, and yet the revenue requirements of the pipelines and distributors can include these sunk capacity costs because the marginal cost of supplying gas to consumers exceeds the average cost in almost all cases.

152. *See* note 117 *supra*.

153. The Wisconsin Public Service Commission recently has required that all new gas customers pay a one-time connection charge reflecting the full cost of gas main extensions required to provide the connection. Wisconsin Fuel & Light Co., No. 6640-GR-1 (Oct. 25, 1977), *summarized in* 101 PUB. UTIL. FORT. 51-52 (Jan. 5, 1978).

Finally, the bulk of the costs of storing gas are avoidable and thus should be included in the calculation of the marginal cost of serving those customers who receive service in part through the use of storage facilities. Quite obviously, in the typical situation of a pipeline that injects gas into storage during the six warm months of the year for withdrawal during the six cold months, the costs of storing gas should not be imposed throughout the year. The most appropriate treatment of storage costs is recovery through imposition of a storage cost surcharge on all gas consumed during the period in which gas is being withdrawn from storage.[154] This will place the benefits and costs of storage on the same group of consumers, and market forces could be relied upon to produce the optimal expenditure on storage.

To summarize briefly, the marginal cost of serving each consumer would consist of: (1) the cost of acquiring the highest priced gas supply purchased by the supplier, including the cost of installing new facilities to transport that supply; (2) the avoidable costs of transporting and distributing the supply; (3) the cost of additional distribution capacity required to serve a new customer, recovered in the form of a one-time attachment fee; (4) the administrative costs of providing service to each customer, recovered in the form of a separately stated charge on each bill; and (5) the cost of storing gas, imposed as a surcharge on the bill of each consumer receiving gas during periods in which gas is being withdrawn from storage.

### B. *Three Methods of Implementing Marginal Cost Pricing*

The following discussion of three potential methods of reflecting marginal cost principles in setting natural gas rates proceeds analytically on the assumption that the distributor's rates must reflect its marginal cost. This approach is taken because it is easier to illustrate the effect of marginal cost pricing on the retail level than on the wholesale level. In fact, to obtain the desired effect, the rates of both pipelines and distributors must be based upon marginal cost. To illustrate this fact, consider the typical distributor that purchases gas from a pipeline at a rate of $0.60 per MCF based on the pipeline's average costs. If the pipeline's method of calculating its rates is not changed to reflect its marginal cost, the distributor's marginal cost of gas is only $0.60 per MCF. Yet, if the pipeline

154. Similarly, the costs associated with the operation of peak-shaving facilities should be recovered through a surcharge applicable only to those customers that receive service during the periods in which the peak-shaving facilities are in use.

is purchasing gas at costs varying from $0.20 to $2.00 per MCF, its marginal cost and the distributor's actual marginal cost is $2.00 per MCF, not $0.60 per MCF. Thus, optimal allocative efficiency can be assured only if both distributors and pipelines adopt methods of determining rates that reflect marginal cost.

(1) Inclining Block Rates

Consistent with the desire to limit pipeline and distributor revenues and to limit producer rents on inframarginal production, one method of achieving many of the goals of marginal cost pricing is to establish for each consumer, or class of consumers, an inverted rate form in which the consumer confronts the marginal cost of gas in the last consumption block. The initial units of gas consumed by any customer would have to be priced substantially below marginal cost (and even below average cost) for this rate structure to be consistent with the desire to limit pipeline, distributor, and producer revenues.[155] The price of successive units purchased would increase gradually until the price reached marginal cost in the tailblock of the rate form.

The principle supporting the adoption of inverted rates is that every consumer values the last unit of a good purchased at less than the value he placed on the prior unit. Thus, at least in theory, if the consumer is confronted with a price based upon marginal cost for the last units of gas purchased and a price approaching marginal cost for the immediately preceding units, he will make the same kind of rational decision reflecting accurately the resource costs of his options as he would make if confronted with pure marginal cost pricing. Allocation of gas among consumers would be more efficient because consumers who value the last units of gas at less than marginal cost will forego consumption. Moreover, pipelines and distributors will face the risk that there will be insufficient demand for gas in the marginal cost tailblock of each rate form to permit them to sell their entire gas supply. This will force them to pay no more for a new gas supply than the value placed on the supply by each consumer and to engage in tough negotiations and shopping for new gas supplies.

The inverted rate would perform best in shaping decisions by sophisticated consumers on whether to purchase the last units of gas

155. This assumes that the pipeline or distributor is in the situation most common in the gas industry today in which marginal cost exceeds average cost. In the presently rare situation in which average cost exceeds marginal cost, the revenue constraint requires either the use of average-cost pricing or some form of subsidy combined with marginal cost pricing.

available or to pay for substitutes such as insulation and more efficient combustion equipment, which would reduce their consumption of gas and remove them from the last blocks of the rate form. Unfortunately, many gas consumers are not sophisticated enough to base their decision on the unit cost of gas that they confront in the final consumption block, and many decisions to purchase or forego purchasing gas are based properly upon the average cost of gas to the consumer, rather than the cost of obtaining the last units consumed.

There is some evidence, which seems to be consistent with casual empirical observation, that most residential gas consumers have no idea how much they pay for each unit of gas they purchase or how their gas bill is calculated. They are aware only of the total amount of the bill; consequently, they decide whether to purchase a unit of gas on the basis of the average cost of the gas.[156] Because the average cost of gas to consumers would be unaltered by the inverted rate form, the consumption patterns of this large group of unsophisticated consumers would not be altered. Of course, educating residential gas consumers in the manner in which their bills are calculated could result in better informed decisions by these consumers, and to the extent that educational efforts were successful, inclining block rates would result in a more efficient allocation of gas. Gas distributors probably would not assist voluntarily in such an educational effort,[157] but they could be compelled to assist in that effort by regulatory commissions. In addition, other groups, such as manufacturers of insulation and electrical ignition systems, would have an interest in assisting the public to understand the implications of inverted rates. Even the best-designed system of educating residential consumers concerning the characteristics of inclining block rates, however, would meet only partial success.

Another serious problem with the inclining block rate is that many decisions among alternative purchases or investments are made properly on the basis of average cost. For instance, for two decisions that arise frequently for natural gas consumers—the decision to install initially natural gas burning equipment in a residence and the decision to convert a major unit of combustion equipment from gas to another fuel—the inclining block characteristic and the existence of a tailblock rate equal to marginal cost are irrelevant.

156. *See* Consumer Energy Project, New Hampshire Legal Assistance, *New Hampshire Energy Usage Patterns and Consumer Orientation* (1976).

157. A gas distributor obviously has no incentive to make consumers aware of the high price of marginal units of consumption because consumer awareness can only increase the distributor's marketability risk.

Because these decisions would continue to be made on the basis of average cost calculations that are unaffected by the way in which costs vary from one consumption block to another, these decisions would continue to be made on the basis of gas prices that are understated in terms of the resources required to produce and deliver gas. Thus, while inverted rates would increase the allocative efficiency of the gas market in some respects, they would leave unaffected many of the characteristics of the market that produce the present suboptimal allocation of resources.

Moreover, the inclining block approach almost certainly would increase the transaction costs inherent in pipeline and distributor rate cases by introducing major new issues on which the parties would have conflicting interests and strong incentives to litigate. These issues are not susceptible to resolution through the consistent application of neutral principles founded in reason. For instance, how many different classes of consumers should be identified separately and subjected to a common rate schedule? What dividing points should be used to distinguish consumers subject to one rate schedule from consumers subject to another rate schedule? What degree of upward taper should be imposed for each class of consumer?[158] These transaction costs could be expected to decline over time as a set of relatively settled rules governing each new area of controversy is developed by regulatory authorities. The partial improvement in allocative efficiency resulting from adoption of inclining block rates may justify increased transaction costs, but the case in support of inverted rates for gas distributors is far from clear. As a potential method of adopting marginal cost pricing principles, the inverted rate offers more promise at the wholesale or pipeline level than at the distribution level.[159]

158. Since the goal of the inclining block rate is to confront each consumer with a price based upon marginal cost for the last units of gas purchased, the ideal rate structure would use a different rate curve for each consumer reflecting that consumer's individual consumption characteristics. Such a structure, however, would be far too complex to establish and administer. At a minimum, classes of consumers with relatively common consumption characteristics would have to be established. Dilution of the impact of the marginal cost tailblock would inevitably result because some consumers in each class could increase their consumption without reaching the marginal cost tailblock. Moreover, consumers who are likely to be confronted with decisions based upon average cost—decisions to install initially natural gas combustion equipment or to convert existing combustion equipment to other fuels—should confront a rate curve that produces an *average cost* of gas approaching marginal cost. Yet the effort to confront these consumers with an average cost approaching marginal cost necessarily makes the task of confronting each consumer with the marginal cost of the last unit of gas consumed much more difficult if the pricing scheme remains consistent with revenue constraints. The solution to the problem is largely indeterminate, and protracted litigation between parties with substantial sums of money at stake would be inevitable.

159. The customers of an interstate pipeline typically have characteristics that differ

(2) Marginal Cost Pricing with Consumer Rebates

The second potential modification of pure marginal cost pricing that could be implemented consistent with revenue constraints produces a very simple basic rate structure. Marginal cost is calculated for each class of customers, and each unit of gas purchased by each consumer is priced at marginal cost. The resulting excessive revenues generated by the distributor are returned to consumers in the form of rebates. As long as the rebates have *no relationship* to the volume of gas consumed by the customer, the rebates should not affect the consumer's behavior.[160] With consumer behavior guided entirely by marginal cost, all the problems inherent in the present rate structure should be eliminated. Only those gas supply projects that can yield gas at a cost less than or equal to the value that consumers place on natural gas will be undertaken. Distributors and pipeline suppliers will have proper incentives to bargain for the lowest cost supply available. The gas market will clear automatically, thereby optimizing the efficient allocation of gas among consumers and eliminating the transaction costs of administering the curtailment system.

The potentially significant limitations unique to this method of adopting marginal cost pricing emerge only through analysis of the manner in which the rebate is likely to be distributed to the consumer. The reason for the rebate is to return to the consumer the gains of regulating pipelines, distributors, and producers without

dramatically from the characteristics of a distributor's customers. A pipeline usually provides service to relatively few large distribution customers and large industrial customers. The pipeline's customers are sophisticated enough and have enough at stake in the transaction that they are intimately familiar with the basis on which they are billed. Consequently, there is no potential for confusing average cost and marginal cost as the basis for billing the last units of gas purchased. Also, the distributor customers have no realistic means of entirely substituting another fuel for natural gas. Thus, there is no basis for concern that they will make decisions based upon their average cost of gas. Applying an inclining block rate to the pipeline's industrial customers could present problems, since many of them may be able through conversion to substitute entirely other fuels for natural gas. However, because the rates charged by interstate pipelines to direct industrial customers are not subject to regulation under the Natural Gas Act, the pipeline would have an automatic incentive to base the contract rate applicable to such customers upon marginal cost without any encouragement from regulatory authorities. Thus, inverted rates with a tailblock equal to marginal cost may well provide the easiest and most effective means of implementing marginal cost pricing principles at the pipeline level.

160. It would be more technically accurate to state that a rebate that has no relationship to volume will have no effect upon consumer behavior in terms of a consumer's preference for one good over another—the substitution effect. To the extent that the rebate increases each consumer's disposable income, it will produce increased consumption of all goods by the consumer through the income effect. The income effect of the rebate, however, is of no concern in attempting to obtain an efficient allocation of resources.

affecting the consumer's behavior. To accomplish this, the rebate must have no relationship to the amount of gas consumed by an individual customer, and consumers must recognize that the rebate has no relationship to their gas consumption. The first part of the requirement may produce criteria for determining eligibility for rebates that are considered unacceptable on equitable grounds. For instance, eligibility for a rebate cannot depend upon whether the consumer is receiving gas service at the time the rebate is distributed. If potential new consumers of gas could become entitled to the rebate by deciding to install gas service, they again would be faced with a decision based upon average cost[161] rather than marginal cost, and many consumers who value gas service at less than its cost would choose gas service. Similarly, if historic gas consumers lost their eligibility for a rebate by ceasing to use gas, they would base their decision on conversion to other fuels upon the average cost of gas,[162] rather than its marginal cost, again resulting in overconsumption of gas. Thus, the principle that rebates cannot depend upon the amount of gas used must be enforced rigidly if this pricing system is to be effective. Whether legislators and/or regulators would be willing to adopt a system of rebates that excluded new customers and included old customers who are no longer receiving gas is at least questionable. Only if they were willing to take this step would marginal cost pricing with consumer rebates alleviate the problems inherent in the operation of the natural gas market.

In addition to observing the crucial caveat that rebates not be linked to present consumption, consumers would have to understand that there is no relationship between the rebate and present gas consumption. Given the high percentage of unsophisticated consumers in this market, a real danger exists that consumers would misunderstand the operation of the rebate system and base their decisions on the mistaken assumption that the difference between

161. To illustrate, consider an individual who is building a home and is faced with the decision to install gas or oil heat. The rate for gas service is $2.50 per MCF, while oil costs $2.00 per MCF equivalent. The consumer should and undoubtedly will select oil heat. If the person, however, is aware that by becoming a gas consumer he can become eligible for an annual rebate of $100, he will offset this rebate against the unit cost of gas and will install a gas furnace rather than an oil furnace if he uses less than 200 MCF of gas per year. His decision once again will have been based upon the average cost of gas rather than its marginal cost, and suboptimal allocation of resources will result.

162. This too can be illustrated best through a hypothetical. If a present gas consumer is paying $2.50 per MCF for gas service and he can convert to oil at a cost of $2.00 per MCF equivalent (including capital costs of conversion), he should and will convert. If, however, he now is receiving a $100 per year rebate that he will lose once he converts, he will not convert if he uses less than 200 MCF of gas per year. In short, the decision to convert will be made once again on the basis of average cost rather than marginal cost.

the amount they are billed and the amount of their rebate is their effective cost of gas—they would base their decisions on average cost. Here again, the ability of the rate design to change consumption patterns in important sectors of the market depends upon consumer education. The difference between the mechanics of a rebate system and the mechanics of billing under an inclining block rate schedule, however, should make consumer education substantially easier. To test this empirically unsupported statement, consider whether you are more likely to attempt to read and decipher a typical utility bill or to read and understand a notice accompanying a check that states: "Enclosed is your rebate check. It has no relationship to the price that you must pay for natural gas. Even if you cease using all natural gas or double your consumption, your rebate amount will be the same."

The transaction costs of adopting a system of marginal cost pricing with consumer rebates appear quite tolerable. Essentially, only three steps are involved. First, the utility's revenue requirements must be calculated. This step is identical to the first step in all utility rate cases,[163] and therefore it does not impose any additional transaction costs. Second, the distributor's marginal cost for each class of customers must be determined. This would require some additional effort because agencies that regnlate the natural gas industry typically have not had occasion to calculate marginal costs.[164] As the FPC's recent abortive attempts to impose incremental pricing illustrate, some time will be required for agencies to develop adequate methods of calculating marginal cost. Calculation of marginal cost, however, requires merely that agencies distinguish between avoidable costs and sunk costs—a procedure that can be institutionalized rapidly through the Uniform System of Accounts now used by most agencies that regulate utility rates.[165] The differ-

163. A regulated utility's revenue requirements typically are calculated using the formula RR = E + D + (rate of return x rate base), where RR is revenue requirements, E is expenses, D is depreciation, rate of return is the firm's estimated cost of capital, and rate base is the value of the firm's capital assets used and useful in the regulated business. No change in this method of calculating revenue requirements is necessary to implement marginal cost pricing with a consumer rebate or with an excess profits tax.

164. One step in the present method of setting natural gas rates—determination of the appropriate rate design for the utility—would be eliminated by a change to marginal cost pricing with a rebate or an excess profits tax. The reduction in transaction costs resulting from elimination of the traditional rate design phase of the proceeding would offset all or a substantial part of the transaction costs added by the determination of marginal cost.

165. The Federal Power Commission established a Uniform System of Accounts to govern its regulation of electric and gas utilities in 1937, and it revises the system periodically to reflect the introduction of new technology, new accounting techniques, and new regulatory instruments. The National Association of Regulatory Utility Commissioners (NARUC) has a comparable uniform system. Most state regulatory commissions use one of these two similar

ence between marginal cost times volume expected to be sold[166] and the utility's allowed revenue requirements yields the aggregate amount of the consumer rebate.[167]

The third step in the process is to determine the criteria to be used in apportioning the rebate among consumers. Given the amounts of money at stake and the absence of intuitive standards to guide the agency in determining the allocation of the rebate among classes of consumers, in at least the first few proceedings this step in the rate proceeding could be expected to spark substantial controversy. Definite limits exist, however, to the amount of time and effort that can be put into the process of apportioning the rebate. Apart from the essential criterion that the rebate have no relationship to present gas consumption, how the rebate is divided has no effect on allocative efficiency. Indeed, the decision is one peculiarly appropriate to the political process, and the legislature might reasonably eliminate all transaction costs associated with arguments concerning who gets what share of the gains of regulation by preempting the dispute through the adoption of a statutory formula.

In summary, marginal cost pricing with consumer rebates would be an effective approach to restoring the health of the gas market if, but only if, legislators were willing to adopt a rebate system that did not tie in any way the eligibility or amount of a rebate to present gas consumption. If implemented in a manner assuring that consumers understood that no relationship existed between the rebate and present gas consumption, allocative efficiency in all aspects of the gas industry could be substantially enhanced. Although some additional transaction costs in rate cases could result from adoption of this method of pricing, there clearly would be a net reduction in the total transaction costs incurred in regulating the natural gas industry. The expensive and time-consuming

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systems. This use of uniform accounting systems greatly reduces the transaction costs of public utility regulation by permitting accounting disputes to be resolved in one or two proceedings of general applicability, rather than through ad hoc adjudications in a multitude of separate rate proceedings. *See generally* J. SUELFLOW, *supra* note 109, at 32-56. The present uniform system of accounts is tailored to the calculation of revenue requirements, but an analogous system could be devised for use in calculating marginal cost.

166. Of course, the estimate of volume must be predicated upon the marginal cost rate.

167. The marginal cost rate would be a maximum rate only. There is no need to make the marginal cost rate a minimum rate as well because basing the aggregate rebate on the difference between marginal cost rate revenues and allowed revenue requirements will give the utility a strong incentive to sell its gas at the highest rate approaching marginal cost that market conditions will permit. Moreover, the power to sell gas at less than its marginal cost provides the utility with a means of cutting its losses and avoiding in part the large fluctuations in earnings that can result from errors in forecasting demand. *See* Part VI(C)(4) *infra*.

process of overseeing the curtailment mechanism would be eliminated, and proceedings to consider proposed new gas supply projects could be truncated substantially by limiting the issues to those involving externalities.

(3) Marginal Cost Pricing with an Excess Profits Tax

The third generic approach to implementing marginal cost pricing in the gas industry has characteristics in common with marginal cost pricing with a consumer rebate. The distributor's unit rate would be calculated on the basis of marginal cost, and all gas would be sold at marginal cost, while the distributor's revenue requirements would be calculated in the traditional manner. Under this approach, however, the difference between the revenues produced by the use of marginal cost pricing and the utility's allowed revenue requirements would be taxed instead of being rebated to consumers.[168]

The principal advantage of marginal cost pricing with an excess profits tax is its ability to accomplish the same improvements in allocative efficiency as theoretically are available through adoption of marginal cost pricing with consumer rebates, while eliminating the concern that the rebate system will be structured in a manner that affects consumer behavior. With the difference between marginal cost revenues and average cost revenues entering the treasury and returning to consumers in the form of tax reductions,[169] no possibility exists that consumers would misconstrue their share of the distributed gains of regulation as an offset to their cost of gas.

The transaction costs involved in implementing marginal cost pricing with an excess profits tax would be no greater than those involved in implementing marginal cost pricing with a consumer rebate, and they could be even less. The first two steps in the implementation process—calculation of allowed revenue requirements and calculation of marginal cost—would be identical. The final step of distributing the gains of regulation could be accomplished with less administrative expense by using the existing income tax system

168. The tax should be calculated prospectively rather than retrospectively in order to retain an incentive for efficiency analogous to that created by regulatory lag.

169. The precise form in which the proceeds of the excess profits tax are returned to the economy is not relevant to the efficient allocation of resources. On equity grounds, however, it is at least arguable that part of the proceeds should be distributed in the form of increased welfare benefits because welfare recipients would receive none of the gains of regulation if they were distributed exclusively through income tax reductions. The present regulatory system returns some of the gains of regulation to welfare recipients in their capacity as consumers of energy.

than by establishing a separate mechanism for allocating and distributing consumer rebates. Thus, it follows that marginal cost pricing with an excess profits tax would produce a net reduction in the transaction costs of regulating the natural gas industry. The reduced transaction costs resulting from the elimination of the need for administering a curtailment system and from the ability to limit the inquiry in new gas supply project proceedings to externality issues should far exceed the additional transaction costs introduced in the rate-setting process.

If this method of adopting marginal cost pricing has a unique disadvantage, it is the possibility that some may view the distribution of the gains from regulating the gas industry to taxpayers, rather than to gas consumers, as inequitable. That gas consumers have a unique equitable claim to the gains from regulating the gas industry is not at all clear. A properly structured consumer rebate system over time also would distribute the gains of regulation to a group that is not identical to the group of people receiving gas service at the time the rebate is made. Whether legislators will balk at this characteristic of marginal cost pricing with an excess profits tax is a topic on which only speculation is possible at the present. As discussed in the next section of this Article, dealing with "second best" problems, it is possible to turn this arguable disadvantage of marginal cost pricing with an excess profits tax into an advantage by broadening the scope of the proposed pricing reform to include all fuels subject to rate regulation.

### C. *Constraints on the Implementation of Marginal Cost Pricing*

#### (1) Second Best Problems

The phenomena referred to as second best problems are a traditional impediment to many utility rate reform measures that attempt to improve allocative efficiencies through adoption of new methods of pricing the product of one industry.[170] If the pricing structure of one industry is modified to permit a more accurate reflection of that industry's costs, while the prices of a competing industry's products continue to be determined through the operation of a regulatory system that does not require prices to reflect marginal costs, it is at least theoretically possible that the improvement in the methods of pricing the first industry's products actually will produce a less efficient allocation of resources.

Illustration of second best problems in the context of marginal

170. *See* 1 A. KAHN, *supra* note 20, at 195-98.

cost pricing of natural gas is accomplished best through a simple hypothetical. Assume that a gas utility can provide service to a new home in a town at an average cost of $2.00 per MCF and a marginal cost of $3.00 per MCF. In this situation, the proper concern is that the new homeowner will choose to install gas heat in his home rather than an alternate heating system that might provide equivalent heat at a cost of $2.50 per MCF equivalent. Because the cost of gas that the consumer confronts is less than the cost to society of making gas available to him, and because the real cost of a unit of gas exceeds the cost of alternate sources of heat, the understated cost of gas normally would misallocate resources. Forcing the price of gas to increase to reflect the marginal cost of gas would increase the efficiency with which society's resources are allocated.

Assuming, however, that the alternate heating source available for new homes in the town is electricity, and assuming further that the marginal cost of producing electricity for use in the town is $3.50 per MCF equivalent and that the $2.50 rate at which electricity can be purchased in the town is a product of another regulatory scheme that causes prices to be set at less than marginal cost, a change to marginal cost pricing of natural gas may reduce allocative efficiency. Before the change in methods of setting gas rates, a consumer's choice of gas over electricity minimized costs to society because electricity costs society $0.50 per unit more to provide than natural gas costs. The understated price of both gas and electricity would produce overconsumption of both, but at least the choice between the fuels produced an efficient allocation of resources. If marginal cost pricing is adopted for the natural gas utility serving the town, but not for the electric utility serving the town, the consumer will confront a price for gas of $3.00 and a price for electricity of $2.50. The consumer will choose electricity over gas although the equivalent quantity of electricity costs society $0.50 per unit more to produce.

Second best problems can arise if marginal cost pricing is adopted in the natural gas industry and competing fuels remain subject to methods of rate regulation that produce prices below marginal cost. The two energy sources that presently compete most frequently with natural gas are subject to rate regulation methods that tend to produce a price less than marginal cost. Rate regulation methods analogous to those used in the natural gas industry price electricity below marginal cost,[171] while the entitlements program

171. The traditional method of setting electric utility rates is almost precisely the same as the traditional method of setting gas utility rates. In the case of electric rates, the rate

combined with restraints on the price that can be charged for some domestic crude oil probably produce prices for petroleum products that are less than marginal cost.[172]

The second best problem has at least two partial answers and one complete answer. Beginning with the partial answers, although two of the products that compete with natural gas are priced on a basis other than marginal cost, a great many other complete or partial substitutes are sold in competitive markets not subject to rate regulation. To assume that the prices for these products are based upon marginal cost is reasonable.[173] For instance, coal is an obvious potential substitute for natural gas in some applications,[174] and most of the countless products that can decrease consumption of gas, such as insulation, storm windows, and even sweaters, must be considered potential substitutes for natural gas at the margin. Even if adoption of marginal cost pricing of natural gas distorts the allocation of society's resources from one fuel producing activity to another to some extent, the overall efficiency of resource allocation still could be improved by optimizing the allocation of resources between substitutes such as natural gas and coal, and natural gas and insulation.

Continuing with the second partial response, the potential for misallocation of resources from one fuel producing activity to another probably would be slight if natural gas prices were set at marginal cost and electricity and fuel oil continued to be priced at something less than marginal cost. Apparently, the difference be-

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based upon average costs may be less than the marginal cost of electricity because of the large increases in the capital cost of adding new generating capacity that have been experienced in recent years due to inflation. *See generally* Aman & Howard, *supra* note 14; Cudahy & Malko, *supra* note 110.

172. The present method of regulating the oil industry imposes ceilings on the price that can be charged for old oil produced from domestic sources. It also contains a system of "entitlements" to the old oil that produces an averaging effect on the costs that domestic refiners must incur to obtain crude oil. Although most refined petroleum products are no longer subject to price controls, the continued control of the price paid for old oil from domestic sources and the entitlements program change the shape of the industry supply curve in a manner that almost certainly results in some deviation between marginal cost and price. *See* FEDERAL ENERGY ADMINISTRATION REGULATION 12-18, 73 (P. MacAvoy ed. 1977).

173. A condition precedent to equilibrium in a competitive market is that price equals marginal cost. P. SAMUELSON, ECONOMICS 455 (10th ed. 1976); G. STIGLER, THE THEORY OF PRICE 176 (3d ed. 1966).

174. The price paid for coal may not reflect current marginal cost in many cases because coal is often sold under long-term fixed price contracts. It has been suggested that this divergence of coal prices from marginal cost may create second best problems if marginal cost principles are used to calculate gas rates. RATE DESIGN, *supra* note 15, ch. 8, at 9. This contention appears fundamentally flawed because second best problems arise in the context of substitution decisions, and substitution is not possible for a consumer purchasing coal under a long-term requirements contract without violating the contract.

tween the marginal cost of gas and the regulated rate that consumers confront is siguificantly greater than the difference between the marginal cost of electricity and petroleum products and the prices the consumers must pay for those fuels.[175] Thus, the hypothetical situation used to illustrate the potential for second best problems in fact would exist only rarely, and the misallocation of resources resulting from its occasional occurrence would be insiguificant in most cases.[176]

The complete response to the second best problem is that second best problems should be solved by changing the price-setting mechanism in the electricity and petroleum industries to one that reflects marginal cost principles, not by refraining from changing the inefficient price-setting mechanism in the gas market. Indeed, already a strong movement toward marginal cost pricing exists in the electric utility industry[177] and the oil industry,[178] which indicates

175. In the case of electricity, a rate based upon average cost will be less than marginal cost only if, and to tbe extent that, inflation in the cost of installing generating capacity is not offset by changes in technology that reduce tbe operating cost of new generating capacity. As a result, some electric utilities have marginal costs that exceed tbeir rates while others have rates in excess of marginal cost, depending upon the precise generating capacity mix that each bas installed in the past and plans to install in the future. Sometimes the increases in new generating capacity costs almost precisely are cancelled out by decreased operating costs resulting from tecbnological changes. For instance, in the landmark case in which marginal cost pricing principles were first applied in tbe calculation of electric utility rates, the revenues resulting from average cost rates and marginal cost rates were found to be "approximately equal." Madison Gas & Elec. Co., 5 PUB. U. REP. 4th (PUR) 28, 37 (Wis. Pub. Serv. Comm'n 1974).

In the case of petroleum products, price is likely to be somewbat less than marginal cost because a portion of the supply of oil produced domestically is subject to federal price controls, and tbe entitlements program spreads this inframarginal cost production to all refiners, thereby modifying each refiner's cost curve. The effect of this price-controlled old oil on the price charged for petroleum products, however, is small and decreasing for several reasons. First, most petroleum products are no longer subject to price controls; consequently no dampening of price results from controls at the second and third levels of distribution as exists in the natural gas industry. Second, price controls obviously do not apply to foreign crude oil, and foreign crude accounts for a significant portion of the total crude supply available to United States refiners. Third, price controls apply only to a small and diminishing percent of the supply of crude available from domestic sources. Fourth, petroleum products refined overseas and imported into the United States are not subject to price controls, and tberefore are available only at prices based upon marginal cost. *See generally* FEDERAL ENERGY ADMINISTRATION REGULATION, *supra* note 172. *See also* Kahn, *supra* note 150, at 24.

176. A second best problem resulting from setting natural gas prices at marginal cost without a similar change in oil and electricity prices can occur only in tbose instances in which the marginal cost of natural gas is bigher than the price at which tbe competing fuel is sold, but lower than the marginal cost of tbe competing fuel. Thus, the probability tbat this set of facts exists in a given situation (and hence, the number of situations in which it will exist) is a direct function of the spread between the marginal cost and the price of the competing fuel. Because this spread is relatively small in the case of electricity and coal, particularly in relation to the very large spread for natural gas, only occasional and minor second best problems can be predicted even if marginal cost pricing is implemented solely for natural gas.

177. Marginal cost pricing already bas been implemented on some electric utility sys-

the products of those industries are likely to be priced on the basis of marginal cost long before comparable reforms of gas pricing mechanisms can be implemented. This suggests that second best problems may dictate a rapid move *toward* marginal cost pricing of natural gas,[179] rather than inhibiting such a reform.

One approach to eliminating second best problems could also eliminate the concern about the arguable inequities of the marginal cost with excess profits tax method of pricing natural gas. The prices charged for all energy sources subject to price regulation[180] could be set using the same approach of calculating allowed revenues, setting prices based on marginal cost, and taking the difference from the supplier through a tax. With such a uniform approach to implementing marginal cost pricing of fuels, the group from which the gains of regulation are taken (direct and indirect consumers of all energy sources subject to economic regulation) and the group to whom the gains of regulation are distributed (taxpayers) would be virtually identical.[181]

(2) The Relationship Between Marginal Cost Pricing and Regulation of Producer Prices

The marginal cost pricing methods discussed above are entirely

tems in Wisconsin and New York. *See* Madison Gas & Elec. Co., 5 PUB. U. REP. 4th (PUR) 28 (Wis. Pub. Serv. Comm'n 1974); Kahn, *supra* note 150, at 24. Several other states have initiated generic rate design proceedings to consider implementation of marginal cost pricing on all electric utility systems in the state. *See* Aman & Howard, *supra* note 15, at 1088 n.8. *See also* ELECTRICAL WEEK, Oct. 11, 1976, at 7. Marginal cost pricing may be adopted quite rapidly in the electric utility industry now that the utilities and state regnlatory agencies have had an opportunity to study its impact. There are strong indications that marginal cost pricing of electricity will aid both utilities and the agencies that regulate them by increasing utility earnings stability and reducing the frequency with which rate increases must be sought. *See* Joskow, *Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation*, 17 J.L. & ECON. 291, 317-20 (1974).

178. Full marginal cost pricing of petroleum products is likely to occur as a result of either: (1) passage of the crude oil equalization tax proposed by President Carter in the National Energy Act on April 29, 1977 (*see* 207 ENERGY MNGM'T (CCH), No. 204, pt. 4, § 1401 (May 4, 1977)); or (2) deregulation of domestic crude oil prices. The present mandatory controls of crude oil prices become discretionary in June 1979, and the discretionary authority expires in September 1981. 15 U.S.C. § 760g (1976).

179. If petroleum products and electricity are sold at prices that reflect marginal cost, and natural gas continues to be sold under a rate regnlation scheme that produces gas prices significantly below marginal cost, the potential for consumers to select gas over oil or electricity when gas actually costs society more to produce is apparent.

180. Fuels that are not subject to rate regulation and that are sold in a competitive market in equilibrium will be priced at marginal cost without any governmental intervention. *See generally* P. SAMUELSON, *supra* note 173; G. STIGLER, *supra* note 173.

181. On equitable grounds, a portion of the gains of regulation should be distributed through the welfare system because a significant segment of the public must pay for energy, but would receive no benefits from a tax reduction.

consistent with retention of controls on the prices that natural gas producers can charge for old gas produced at inframarginal costs. Indeed, all three methods were designed in part to respond to that constraint. It is not at all clear, however, that any form of marginal cost pricing could perform effectively consistent with maintenance of regulatory constraints on the price at which new gas supplies can be sold. The gas market probably would not clear without deregulation of new supplies, and retention of price controls on domestic producers certainly would produce a misallocation of resources from domestic production to de facto unregulated production activities associated with natural gas imports and synthetic gas manufacture.

The producer rate regulation scheme originally proposed by President Carter illustrates these phenomena. Under that proposal, domestic gas producers could obtain a maximum of approximately $1.75 per MCF for new gas.[182] The regulatory authority, however, would continue to have no effective means of controlling the prices that could be charged United States companies for gas produced abroad and imported into the United States either by pipeline or in the form of LNG. Moreover, regulators would have very limited control over the prices that must be paid for gas manufactured from coal.[183] The $1.75 per MCF ceiling on the price of new gas from domestic sources would eliminate any possibility that the gas market would clear solely because of purchases of new domestic gas supplies by pipelines and distributors. Producers simply would not produce supplies with a marginal cost greater than $1.75 per MCF, and a consumer price based on $1.75 per MCF energy costs almost certainly would produce excess demand whether the price is calculated using average cost or marginal cost principles. The only conceivable way that the gas market could clear with this kind of constraint on domestic producer prices and on domestic gas production would be through the acquisition of supplies that are not subject to price ceilings (for example, imported LNG). But it appears that supplies from sources of this type will be available only at prices somewhere between $4.00 and $6.00 per MCF.

The net result expressed graphically is a marginal cost curve with an enormous discontinuity covering the $1.75 to $4.00 per MCF range. If the demand curve ordinarily would intersect the marginal cost curve somewhere in this wide range, which it probably would, the market would not clear. No pipeline or distributor would buy

182. H.R. 8444, 95th Cong., 1st Sess. § 404, 123 CONG. REC. 8265, 8310, 8313 (daily ed. Aug. 2, 1977).

183. The price of the coal used to manufacture synthetic gas would largely determine the price at which such synthetic gas is sold. Coal is not subject to rate regulation.

gas at a price above $4.00 per MCF because it would lose too many customers. With the market unable to clear through the price mechanism, administrative allocation (curtailment) would remain necessary, and the interaction of marginal cost pricing and curtailment would impair the effectiveness of any marginal cost pricing scheme in achieving the goal of enhanced allocative efficiency. If the demand curve intersects the marginal cost curve somewhere to the right of the discontinuity, the market would clear, but only through the incurrence of greater costs than would be necessary if producer prices were unconstrained. Supplies of imported LNG that are only available at a marginal cost to the pipeline of $4.00 to $6.00 per MCF would be purchased instead of new domestic gas supplies that could be produced at marginal costs in the $1.75 to $4.00 per MCF range.

Thus, the effectiveness of any form of marginal cost pricing of gas at the wholesale and retail level in enhancing allocative efficiency depends in large part upon the willingness to remove the regulatory constraints now imposed on the price that domestic producers can charge for new gas supplies. Fortunately, because most authorities agree that the gas production industry is structurally competitive[184] and that market forces brought to bear by marginal cost pricing could be expected to eliminate concerns that pipelines will not shop and bargain hard for new gas supplies, the adoption of some form of marginal cost pricing at the wholesale and retail level should eliminate any potential justification for retaining price controls on new gas production.

(3) Lingering Problems in Financing Major Gas Supply Projects

Essentially, two approaches can be taken to the interrelationship between rate design and financing of capital-intensive gas supply projects, such as coal gasification projects and LNG import proposals, which can produce gas only at high unit costs. One can assume simply that all these projects should be encouraged, and a pricing system be adopted to maximize the prospects for successful financing independent of the economic merits or demerits of the project as reflected in the decisions of potential consumers and investors. The present system of pricing yields this result. It has obvious disadvantages because it provides no mechanism for determining whether scarce capital should be invested in natural gas supply projects or in other kinds of projects that may be capable of alleviating at less cost the aggregate supply-demand imbalance in

184. *See* note 56 *supra* and accompanying text.

the energy market. Nor does it provide a mechanism for selecting which of the many gas supply projects competing for the scarce capital are most economically desirable.

Alternatively, one of the kinds of pricing systems proposed in this Article can be adopted to permit the decision whether to begin a project to depend upon the willingness of consumers and investors to commit to participate in the project based upon their perception of its costs, risks, and benefits. The obvious advantage of the second approach is that it provides a market test of the desirability of committing scarce resources to the project, rather than to other means of meeting consumer needs. Consumers' and investors' evaluations of the costs, risks, and benefits associated with the project, however, are critical to the success of this second method. If, through regulation, some of the benefits associated with the projects are withheld from the consumers and investors that are offered an opportunity to participate in the project, some economically worthwhile projects will not begin because they are not financially viable.

One of the ways in which the financing decision can become disassociated from the economic desirability of the project is through the attachment of a threat of diversion of the project's supply output. The only way to avoid this threat is to establish a pricing system that will clear the market through the price mechanism. Once consumers realize that the threat of diversion of supplies through direct governmental intervention has been removed, they can evaluate the complete package of advantages and disadvantages associated with a proposed project. Thus, one of the prerequisites to changing the method of rate desigu in the natural gas industry is assurance that the combination of pricing methods used at all levels, from production through retailing, will clear the market without governmental intervention.

Potential investors in gas supply projects, like potential consumers, also must be confronted with the full costs, benefits, and risks of a project if the market test is to yield reliable results. Essentially, this requires a decision to leave free from regulatory constraints the price that can be obtained for the output of a new gas supply project of any variety, including coal gasification plants and LNG import projects.[185] This necessarily follows from the nature of

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185. The portions of the project that must be left free of economic regulation are those in which substantial capital investments must be placed at risk. In most situations, this would consist only of the production or manufacture of the gas and, in the case of LNG, the cryogenic transportation and handling facilities. Occasional situations may exist in which the transportation of a new gas supply by pipeline is such a capital-intensive, high-risk venture that a market test of the economic viability of the project requires deregulation of even the

the market test that is being relied upon to achieve the economically desirable result. An example may help to illustrate the point. Assume that an investor has a choice between two projects with identical characteristics except that one project is subject to maximum rate regulation and the other is not. The first project is a coal mine; the second is a coal gasification plant. Both are high capital investment projects with long-term returns, and in both cases, periods will occur in which uncontrollable factors, such as an unusually warm winter, will depress demand for the output of the project to the point at which the entire output cannot be sold at a price equal to cost. In both cases periods also will occur in which factors, such as an unusually cold winter, will cause demand for the output of the project to increase to the extent that the entire output can be sold at prices in excess of cost. In this highly realistic situation, the project whose output is subject to maximum rate regulation always will be rejected in favor of the unregulated project although, from a societal standpoint, the projects are comparable. This is because maximum rate regulation removes the opportunity to sell at prices in excess of costs during periods of high demand. This potential advantage is inherent in the unregulated project, and the present value of expected excess profits can be balanced by the prospective investor against the present value of expected losses incurred during periods of low demand.

Fortunately, as in the case of producer prices for new gas supplies, no economic justification exists for applying maximum rate regulation principles to new nontraditional gas supply projects.[186] Consequently, the need to keep these projects free of economic regulation should not present an impediment to the adoption of more rational wholesale and retail rate designs. Once the investor in a gas supply project is permitted (and required) to consider all of the costs and benefits of a project, he then can choose to negotiate with potential consumers to exchange some of those costs and benefits—by

pipeline transportation segment of the project. The proposed pipeline from Prudhoe Bay to the lower 48 states costing over $10 billion is certainly such a venture. The alternatives to deregulation of the pipeline transportation portion of such a project appear to be: (1) permit the use of a tariff that imposes all risks of the project on the consumer; (2) authorize government guarantees of the investment in the project; or (3) simply decide administratively that the project will not go forward. *See generally* Brief of Department of Treasury, El Paso Alas. Co., FPC No. CP 75-96 (Dec. 1976). *See also* Kahn, *supra* note 105, at 15. A market test of the economic desirability of the project appears far preferable to any of the other three options.

186. The present competitive structure of the natural gas production industry should not be altered substantially by the introduction of nontraditional sources of gas supply, such as LNG, SNG, and Alaskan gas. If anything, the competitive structure of the market should be enhanced as additional sellers enter the market.

signing a long-term fixed price contract with a take-or-pay clause.[187] In such a situation, of course, the need to permit the consumer to retain the benefits of the bargain by removing the threat of curtailment and the need to permit the investor to internalize all potential benefits by removing maximum price constraints merge as elements essential to a reliable market test of the project.

(4) Potential Effects on Pipeline and Distributor Earnings Stability

In terms of optimizing efficient allocation of resources, earnings stability is a matter of total indifference.[188] A pricing system that achieves an optimal allocation of resources also can produce wide fluctuations in a company's rate of return from one year to another. For two reasons, however, some attempt should be made to keep gas pipeline's and distributor's rates of return within a relatively narrow range from year to year. First, a utility's cost of capital is likely to increase if earnings fluctuate widely. An investor does not view two companies as equivalent risks simply because both have an average rate of return of fifteen percent over a ten year period. If one company's earnings fluctuate from eight percent to twenty-two percent, and the second company's earnings fall consistently in the thirteen to seventeen percent range, the first company will be considered a higher risk investment, and investors will insist on receiving a premium to invest in it.[189] Second, gas utilities and the commissions that

187. Investors have indicated an unwillingness to assume many of the risks associated with major new gas supply projects, and have insisted that gas purchasers assume much or all of the risks of marketability, project noncompletion, and even interruption of gas supply. *See, e.g.*, Transwestern Coal Gasification Co., UTIL. L. REP. (CCH) ¶ 11,669 (1975); Columbia LNG Corp., 96 PUB. U. REP. 3d (PUR) 389 (1972). To the extent that purchasers of gas are willing to accept these risks voluntarily (for instance as a *quid pro quo* for a fixed price contract), the project can be considered to have passed a market test of its economic desirability. In some cases, however, the project sponsors have indicated that investors will not put funds at risk unless consumers are forced involuntarily through tariff provisions to accept many of the risks usually assumed by investors. In such cases it is impossible to determine whether investor reluctance to put funds at risk is a result of their perception that the risks of the project are too great or that the rate of return allowed by the regulatory agency is too low. Because risk and rate of return are directly interrelated, the impact of each cannot be assessed independently. Deregulation of major gas supply projects would eliminate this problem by simultaneously removing artificial constraints on the investor's rate of return and precluding the sponsor from shifting project risks involuntarily to consumers through tariff provisions. Potential investors then would be confronted with the total risks and benefits of the project, and their decision to invest or not would provide a reliable market test of a project's economic desirability, at least absent proof of significant imperfections in the capital market.

188. *See* Kahn, *supra* note 105, at 12.

189. E. SCHWARTZ, CORPORATION FINANCE 203 (1962); *see* R. JOHNSON, FINANCIAL MANAGEMENT 8-9 (4th ed. 1971).

regulate them could be exposed to periodic expressions of public outrage if company earnings are permitted to fluctuate widely over time. The criticism that could be expected in the years of high earnings is theoretically unjustified,[190] but widely held views can present real problems whether or not the views have a good foundation.

The effect that the three suggested variants on marginal cost pricing would have upon gas utility earnings stability is unclear. Because the unit rate resulting from any of the three rate designs includes some elements of cost that are not variable in the very short term, within a winter heating season for example, and the unit rate necessarily is predicated upon a forecast of units sold during a particular time period, any variation between the forecast demand and actual demand will produce a corresponding variation of actual rate of return from theoretically allowed rate of return. Of course, these uncontrollable fluctuations in earnings occur under the present method of rate design;[191] consequently, the only potential cause for concern would be an increase in earnings fluctuations because of the new rate design. To determine the extent, if any, of the increase in earnings fluctuations resulting from imposition of some form of marginal cost pricing would require considerably more analysis. Some increase in earnings fluctuations, however, reasonably could be expected because of the increased sensitivity of volumes sold to short-term changes in demand.[192]

Any undesirable tendency toward decreased earnings stability could be made tolerable through modest changes in the rate instruments used to calculate maximum unit rates, or the amount of an excess profits tax or consumer rebate if pricing systems using those devices were implemented. Automatic and semi-automatic cost pass-through devices, such as purchased gas adjustment clauses, are available to stabilize earnings to some extent. Indeed, adoption of marginal cost pricing would reduce the basis for concern that the availability of purchased gas adjustment clauses may create an incentive for imprudent expenditures by utilities. The market-induced potential for least cost purchasing that would result from

190. The periods in which the utility earns a rate of return higher than that theoretically allowed by the regulatory commission should be offset by periods in which the earned rate of return is less than the allowed rate of return.

191. For instance, the FPC's recent modification of the *Seaboard* cost allocation formula to include 75% of capacity costs in the commodity component of a pipeline's rates has resulted in earnings deterioration on pipeline systems that experience a greater than anticipated decrease in gas supply available for sale. *See* United Gas Pipe Line Co., UTIL. L. REP. (CCH) ¶ 11,954, at 12,266-67 (1977).

192. *See generally* RATE DESIGN, *supra* note 15, ch. 9, at 1-11.

marginal cost pricing might provide an effective substitute for regulatory lag as a source of incentive for efficiency. To the extent that automatic pass-through devices fail to bring earnings fluctuations within tolerable boundaries, some of the more innovative methods of adjusting rates to keep rate of return within a predetermined zone could be adopted.[193] In short, although marginal cost pricing may increase the need to be responsive to utility earnings stability considerations, the devices available under present regulatory procedures should be adequate to respond to any perceived problems of this kind.

(5) Potential Effects on Pipeline and Distributor Cost of Capital

Even if marginal cost pricing produces no decrease in gas utility earnings stability, an increase in a utility's cost of capital can be expected due to the real increased risks to which utilities are exposed under marginal cost pricing. When marginal cost exceeds average cost, one of the principal effects of marginal cost pricing is to increase the utility's exposure to marketability risks. The investment community will perceive this increased risk, and the utility's cost of capital will adjust accordingly. Higher allowed rates of return to pipelines and distributors must be accepted as an inevitable consequence of imposing marketability risks through marginal cost pricing.

(6) Political and Institutional Constraints

The preceding discussion has focused on the theoretical advan-

193. The utility earnings stability problems resulting from the combination of regulatory lag and high inflation in recent years have produced suggestions for a variety of automatic revenue adjustment devices. *See* Kendrick, *Efficiency Incentives and Cost Factors in Public Utility Automatic Revenue Adjustment Clauses,* 6 BELL. J. ECON. 299 (1975); Latimer, *The Cost and Efficiency Revenue Adjustment Clause,* 94 PUB. UTIL. FORT. 19 (Aug. 15, 1974); Renshaw, *A Note on Cost and Efficiency Revenue Adjustment Clauses,* 101 PUB. UTIL. FORT. 37 (Jan. 5, 1978). The broadest form of revenue adjustment clause adopted to date permits automatic adjustment of an electric utility's rates to reflect all changes in costs every three months in order to assure that the utility's earned rate of return coincides with its allowed rate of return. Public Serv. Co., 8 PUB. U. REP. 4th (PUR) 113 (New Mex. Pub. Serv. Comm'n 1975). *But see* United Gas Pipe Line Co., UTIL. L. REP. (CCH) ¶ 11,954 (1977) (rejecting a variable volume adjustment clause proposed by a gas pipeline as a revenue stabilizing device).

Of course, the problem with all such rate adjustment clauses is that they eliminate regulatory lag as a source of incentive for efficiency. Kahn, *supra* note 105, at 12-13. To the extent that requiring natural gas pipelines and distributors to confront a siguificant marketability risk through marginal cost pricing creates independent incentives for efficiency, greater use of automatic revenue adjustment clauses may be possible consistent with the goal of inducing efficient performance by regulated utilities. If marginal cost pricing with an excess profits tax is employed, tbe adjustment to revenues would have to be achieved through an automatic modification of the amount of tax rather than through an allowed change in the rates charged by the utility.

tages and disadvantages of implementing in some manner marginal cost pricing in the natural gas industry. To bring this discussion into the context of the present regulatory scheme, political and institutional constraints must be considered in two respects. First, marginal cost pricing must be imposed by someone. Second, the method of implementation must assure that gas utility rates actually reflect marginal costs. Even a federal statute mandating marginal cost pricing would not assure its actual implementation by resistant state regulatory authorities, given the potential for intentional or inadvertent misdesignation of cost components.

Any viable attempt to implement marginal cost pricing in the gas industry must include the following elements: (1) adoption of marginal cost pricing required by federal statute on *all* gas utility systems;[194] (2) a reasonably uniform method of calculating marginal cost applicable to all utility systems; (3) a major continuing role for state authorities in economic regulation of the gas distribution industry; and (4) built-in incentives for state regulatory commissions to calculate accurately both marginal cost and revenue requirements.

The first requirement simply reflects the political reality that no state would be likely to perceive marginal cost pricing of natural gas to be in its best interests as long as other states continue to permit gas prices to be set based upon lower average costs.[195] If one state adopted marginal cost pricing and a neighboring state did not, the state with marginal cost pricing would fear losing some of its industrial base to the neighboring state. Moreover, pressure from consumers interested principally in the nominal cost of utility services and from regulated utilities interested in retaining the relatively risk-free status inherent in average cost pricing probably will have much greater impact upon most state legislators than concerns

194. Even if it is ultimately held that the Natural Gas Act empowers the FERC to require adoption of some form of marginal cost pricing by gas distributors that receive gas from interstate pipelines—a holding that would stretch the boundaries of federal jurisdiction under the Act to their limits, see note 71 *supra*—the FERC could require only some form of inclining block rate. Since the inclining block rate is the least effective means of rationalizing consumption patterns at the retail level, see Part VI(B)(1) *supra*, a federal statute specifically requiring marginal cost pricing combined with consumer rebates or an excess profits tax is essential.

195. An argument can be made that it is in the best interest of any state to adopt marginal cost pricing because the elimination of gas curtailment in the state as a result of the adoption of marginal cost pricing eventually would make that state more attractive to gas consumers than the neighboring states, notwithstanding its higher nominal gas rates. The author, however, is not optimistic tbat most or any state commissions would perceive this advantage in the face of outrage by consumers displeased with higher rates and regulated utilities concerned with greater risks.

about efficient allocation of resources.[196] Federal legislators, under pressure from an administration and the international community to reduce United States energy consumption and with little reason to fear losing industries to neighboring jurisdictions, are much more likely to find marginal cost pricing palatable.[197]

Similar considerations dictate assurance of a reasonably high degree of uniformity in the method of calculating marginal cost adopted by each regulatory agency through the establishment of binding federal guidelines. Each state might perceive an advantage in understating marginal cost in an effort to keep both consumers and regulated utilities within the state happy. Thus, federal involvement is essential, at least in mandating marginal cost pricing and setting binding uniform accounting rules for calculating marginal cost.

On the other hand, both political reality and administrative efficiency dictate retention of the state utility commission's dominant role in the process of regulating gas distributor rates. Congress would be unwilling to take from the states the power to determine

196. Professor Joskow has hypothesized that regulatory agencies "seek to minimize conflict and criticism appearing as 'siguals' from the economic and social environment in which they operate, subject to binding legal and procedural constraints imposed by the legislature and the courts." Joskow, *supra* note 177, at 297. If this description of regulatory agencies as institutions is accurate—and it seems to be more realistic than the other behavioral models suggested to date—state agencies regulating gas utilities will continue to use average cost as the basis for gas utility rates because this course of action will minimize friction between gas consumers and gas distributors. Of the potential sources of friction with whom regulatory agencies must contend, only environmentalists would appear to have an interest in encouraging marginal cost pricing of natural gas, and they have not yet surfaced as a significant force in natural gas rate proceedings—perhaps because natural gas supply projects are considered a less significant threat to environmental values than are electric generating plants. As more gas supply projects with significant potential for environmental degradation are proposed, environmental groups may become more active in natural gas rate proceedings. The increase in proposals to build cryogenic receiving terminals for LNG, to construct water-intensive coal gasification facilities, and to begin drilling in the Atlantic outer continental shelf may cause environmental groups to become a more siguificant source of friction in future natural gas rate cases.

197. The Carter Administration has emphasized that: "*The pricing of oil and gas should reflect the economic fact that the true value of a depleting resource is the cost of replacing it.*" White House, *The National Energy Plan, reprinted in* 204 ENERGY MNGM'T (CCH) No. 207, pt. 3 (May 4, 1977) (emphasis in original).

Fernand Spaak, head of the European Communities Commission's delegation to the United States, is highly critical of the United States as the only nation in the world whose consumers do not pay full world prices for oil and natural gas. According to Mr. Spaak, the resulting excess consumption by United States consumers adversely affects global supply and demand for energy. Speech to the District of Columbia Bar Association Ten Nation Conference on Energy Conservation (Feb. 23-24, 1978), *reported in* 238 EN. USERS REP. (BNA) 28 (Mar. 2, 1978). For a well-documented argument that United States energy policy violates obligations imposed by international agreements to which the United States is a party, see Murphy, *The International Energy Program: An Assessment*, 26 DE PAUL L. REV. 595 (1977).

gas utility rates and allowed rate of return. Even if Congress were willing to do so, the elaborate federal bureaucracy required to replace the state commissions would be incapable of accomplishing this task as efficiently as state commissions. Thus, although the federal government should establish uniform accounting methods for calculating marginal cost, state utility commissions should retain the function of determining allowable costs, estimating volumes to calculate utility revenue requirements, and setting the utility's allowed rate of return.

Finally, even with the federal government exercising some degree of control over the calculation of marginal cost, the institutional constraints affecting state utility commissions must be considered and accommodated within the new system for setting rates. Utility commissions now must set unit rates and allowed rate of return simultaneously, in a manner that will accommodate the conflicting interests of the consumer in obtaining the lowest nominal rate and of the utility in obtaining the highest rate of return. If commissions set rates too high, consumers will apply pressure to get it reduced; if commissions set rates too low, utilities will apply pressure to get it increased. This is the inherent conflict in the interests of its two constituencies that causes state commissions generally to come to the "right" decision. In its two most promising forms, however, marginal cost pricing makes the calculation of the nominal cost of gas to consumers and the allowed rate of return to the utility independent of each other. Apparently, state commissions could serve the interests of both its major constituencies by understating marginal cost while allowing a rate of return greater than the utility's cost of capital. This would have the undesirable consequences of reducing the effectiveness of marginal cost pricing and transferring wealth from consumers (or taxpayers) to distributors. The establishment of federal guidelines for calculating marginal cost is a partial response to the incentive to understate marginal cost, but it is not at all responsive to the incentive to overstate allowed rate of return. A countervailing incentive for state commissions to maximize the difference between a utility's allowed revenue requirements and the gross revenues obtained from marginal cost pricing must be incorporated into the system if the new rate design is to achieve its goals.

In the case of marginal cost pricing with consumer rebates, the institutional incentive to maximize the difference between allowed revenue requirements and marginal cost revenues is built into the system. A commission can take credit politically for the large rebate received by each consumer. Therefore, maximizing the size of the rebate would be in its best interest. For marginal cost pricing with an excess profits tax, the institutional incentive would be relatively easy to create simply by permitting the state to receive all or a substantial part of the proceeds of the excess profits tax. The state government as a whole would have a strong incentive to maximize the amount of the tax, and the state regulatory commission would probably respond by institutionalizing the revenue-maximizing goals of the state government. The regulatory agency could take much of the credit politically for any reduction in other state taxes resulting from the imposition of a high excess profits tax on utilities. Through either mechanism, the incentive to maximize the difference between allowed revenue requirements and marginal cost revenues would be sufficient to balance the counter-incentives to minimize nominal costs to the consumer and maximize utility rate of return. Consequently, a reasonably accurate calculation of marginal cost and revenue requirements would emerge from the rate proceeding.

## VII. Conclusion

The preferred prescription for the seriously malfunctioning natural gas market that emerges from this analysis would require the following three changes in the statutes and procedures now used to regulate the natural gas industry.

First, at the retail or distributor level, marginal cost pricing with an excess profits tax appears to offer the best opportunity to improve allocative efficiency at tolerable costs. With adoption of such a pricing system required by federal statute and uniformity of accounting methodology assured through implementation of mandatory federal guidelines for calculating marginal cost, state regulatory commissions would implement and administer this kind of pricing system effectively and efficiently, assuming that the state received the proceeds from the excess profits tax. The only other modifications of present state commission policy that this change in rate-setting methodology would require are somewhat greater sensitivity to potential fluctuations in utility earnings and allowance of slightly higher distributor rates of return. A major advantage of the change, in terms of the state commission's obligations, would be the elimination of the costly and frustrating task of overseeing gas curtailments by distributors. In addition, state commissions could limit their review of gas supply projects proposed by distributors to alleged costs and benefits external to the transaction. From the broader societal viewpoint, the change would increase markedly allocative efficiencies in the consumption of natural gas and would permit distributors to make better informed decisions to purchase additional quantities of gas from pipeline sources or to develop their own supplies of gas. Marginal cost pricing with consumer rebates is not likely to be as effective as marginal cost pricing with an excess profits tax because of the danger that the rebate system will not be true to the critical principle that the rebate cannot be related in any way to gas consumption, and because of the difficulties inherent in educating gas consumers to ignore the rebate in calculating the cost of gas service. Inclining block rates with a tailblock based on marginal cost is a poor third choice for adoption at the retail level.

Second, at the wholesale level, the three methods of reflecting marginal cost in pipeline rates are about equally effective and efficient. The different characteristics of the pipeline's market eliminate the concerns that led to the relegation of marginal cost pricing with a customer rebate and inclining block pricing to second and third place for adoption on the retail level.[198] In fact, inclining block pricing may provide the easiest method of incorporating marginal cost principles at the pipeline level. The only other changes in federal regulatory procedure that the change to marginal cost pricing would dictate are increased sensitivity to pipeline earnings stability and some increase in the rates of return allowed to pipelines. The resulting advantages to the federal regulatory commission would be analogous to those described above as accruing to state commissions. The heavy burden of administering the curtailment system would be removed, and the process of reviewing gas supply projects proposed by pipelines could be truncated greatly. Again, from a societal point of view, resource allocation on both the consumption and production side would be enhanced significantly at the same time that the transaction costs of regulating the gas industry are reduced.

Third, at the point of initial sale, or the producer level, continued imposition of price constraints on old inframarginal cost production is desirable. Restraints on the price of gas from new wells or from nontraditional sources of gas supply, however, almost certainly would render largely ineffective any effort to improve the operation of the gas market through new methods of setting prices at the wholesale and retail level. Because the natural gas production industry is structurally competitive, the incentive for purchasers of gas to shop and bargain for the cheapest gas supply available that is created by the adoption of marginal cost pricing should remove most of the basis for concern that deregulation of new gas supplies

198. *See* note 159 *supra*.

will result in windfall profits to producers. To the extent that some concern continues that producers will be able to earn excess rents on new gas produced at inframarginal costs, an excess profits tax is much preferable to direct restraints on prices as a means of eliminating the potential for windfall profits.