AVERAGE COST PRICING OF NATURAL GAS: A PROBLEM AND THREE POLICY OPTIONS

PREPARED FOR THE DEPARTMENT OF ENERGY

FRANK A. CAMM, JR.

R-2282-DOE
JULY 1978

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[illegible] of The Rand Corporation [illegible]
[illegible] policies of the sponsors of Rand research.

Library of Congress Cataloging in Publication Data

Camm, Frank A., 1949-
Average cost pricing of natural gas.

([Report] - Rand Corporation ; R-2282-DOE)
Bibliography: p.
1. Gas, Natural--Prices--United States.
2. Price policy--United States. I. United States. Dept. of Energy. II. Title.
III. Series: Rand Corporation. Rand report ; R-2282-DOE.
AS36.R3 R-2282 [HD9581.U5] 081s [338.4'3665'730973]
ISBN 0-8330-0048-9 78-15724

Published by The Rand Corporation

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PREFACE

This report was prepared as part of Rand's Energy Policy Studies Program, sponsored by the Energy Research and Development Administration (ERDA), now incorporated in the Department of Energy. It grew out of work within that program on institutional constraints to the introduction of new energy technologies as viable alternatives to increasingly more costly traditional energy sources.

The report examines a serious obstacle imposed by state and federal regulatory institutions on the introduction of residential and commercial energy alternatives. A byproduct of these institutions' efforts to control utility profits is a subsidy to natural gas, a direct competitor with such technologies as solar heating, heat pumps, thermal storage, and insulation.

The report should be of interest to anyone concerned with energy policy for the residential and commercial sector and for these technologies in particular. It is written from an economic point of view, and noneconomists may have some difficulty with specific arguments in the text. The author begs the noneconomists' patience in places where the going gets tough and suggests that they check the footnotes for additional explanations of the arguments or that they simply be willing to take the author's word for it. Economists and noneconomists alike live and work with the consequences of the gas subsidy. It is hoped that this report will lead readers of either persuasion to a better understanding of this policy issue.

SUMMARY

The gas provided by a utility is typically purchased on long-term contract. The current price of new contracts is substantially higher than that of older contracts. Current regulation of gas utility profits requires that the price charged for gas be an average of the historical prices of all contracts from which that gas is obtained. Hence, the price that utilities charge for gas is lower than the cost to the utility of obtaining new gas: average cost pricing of gas leads to a price lower than the marginal cost of gas. *Current regulation of gas utility profits subsidizes the use of natural gas.*

This subsidy has two detrimental effects. First, it encourages gas consumers to use too much gas. Inevitably, in some activities, the value of the gas to them is less than the cost of providing new gas for their use. Current regulation of utility profits encourages the waste of a valuable energy resource. Second, the subsidy discourages gas users from switching to other energy sources that could provide them with the same amenities at a lower cost than the real cost of the gas they use. Among the energy sources that may be affected in this way are "new" technologies: solar collectors, heat pumps, thermal storage, and insulation, among others. Current regulation of utility profits acts as a barrier to the entry of new energy technologies.

This report outlines this problem and illustrates it with several examples. It then examines three alternative types of possible policy responses to the problem. The first calls for a shift from average cost pricing of gas to marginal cost pricing: charge gas users the real cost of providing the gas they use. Unfortunately, this alternative causes the very difficulty that average cost pricing is typically aimed at overcoming: it gives utilities "excess" profits. The report examines lifeline rates, gas stamps, excess profit taxes, and franchise fees as alternative means of extracting excess profits and returning them to consumers. Lifeline rates are simple but continue an implicit subsidy for gas use. Gas stamps, properly implemented, overcome this problem. An excess profit tax or franchise fee can do the same thing;

either in fact can be designed to be fiscally equivalent to gas stamps. To choose among the three, we would have to weigh their relative administrative and political costs.

A second policy alternative allows average cost pricing to continue, and uses taxes and subsidies to deal with it. The report shows that a tax on gas use can be made fiscally equivalent to marginal cost pricing with redistribution of excess utility profits. But such a tax will have political and administrative characteristics that differ from those of marginal cost pricing. Alternatively, we can recognize the subsidy that current regulation provides to gas and extend it to substitute technologies such as solar collectors and heat pumps. This solution eliminates the discrimination against new technologies, but it creates two problems. First, it continues to encourage overuse of costly gas and extends this encouragement to the overuse of other energy sources. That is, it encourages the use of energy in some activities in which the value of that energy is not sufficient to cover the real cost of providing it. Second, all potential substitutes for gas must be subsidized to eliminate the discriminatory effect of the regulatory subsidy to gas. Among them, we could expect to find not only fuel oil and electricity but also passive solar applications, such as adobe walls and other special architectural and landscaping designs. This raises a question of how much we are willing to subsidize in order to overcome the problem of average cost pricing of gas.

The third alternative calls for utilities to buy technologies that could replace gas and include their cost in the determination of the "average cost price" at which the utility will provide energy. The report shows that this scheme is analogous to the subsidy program discussed as our second solution and raises all the same difficulties. It also introduces two new complications. First, it closes all competitors but the utility out of the market for alternatives to gas. This happens because only the utility is in a position to subsidize these alternatives. Hence, this "utility ownership" solution eliminates competition in a market where it would, in all probability, thrive. It extends the monopoly influence of the utility, the very

thing the troublesome regulation dictating average cost pricing was designed to remedy. Second, the way in which the regulation of utility profits is applied encourages the utility to use more capital than would be cost-justified in a competitive market. Extending utility control from gas alone to the alternatives to gas also extends this tendency to overcapitalize. We can expect the utility to overcapitalize these alternatives and hence provide them to the consumer at a higher real cost than would a competitive market. In sum, the utility ownership solution not only extends the influence of a utility's natural monopoly but also makes certain that consumers can receive alternatives to gas only at an excessive real cost.

The report closes with a comparison of these three alternative approaches to the problem of regulation-induced average cost pricing. It cannot choose among them in a definitive way without more information on their political and administrative features. But it can suggest which deserve further serious consideration. On the basis of their effects on total national income, either marginal cost pricing with redistribution or average cost pricing with an excise tax on gas offers the most attractive option. Some forms of subsidy may raise national income above its level under current average cost pricing, but the complexity of multiple subsidies raises doubts about this option. Any of them dominate utility ownership of new technologies.

ACKNOWLEDGMENTS

This report bears the mark of discussions with and written comments from many colleagues. I wish to thank especially Leland Johnson and Willard Manning for their penetrating and constructive reviews of the final draft. Jan Acton, Walter Baer, Stephen Chapel, William Hederman, Frederick Hoffman, James Hosek, Edward Merrow, Charles Phelps, Phillip Sher, Jeffrey Smith, Rodney Smith, Charles Wolf, Jr., and Christopher Worthing commented on earlier drafts. Walter Baer, William Harris, and Edward Merrow provided helpful data for the study. I thank tham all and take full credit for whatever errors remain.

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I. INTRODUCTION

A number of obstacles discourage the introduction of new energy technology. One of the most important in the residential-commercial market for energy is "average cost" pricing of natural gas. State and federal regulators impose this form of pricing on contracts between pipelines and utilities and on those between utilities and their final customers. This kind of pricing presents final consumers with a price for gas that is based on a weighted average of the prices utilities and pipelines pay for gas, a weighted average significantly lower than the real replacement cost of gas. *Average cost pricing of gas causes final consumers to undervalue the gas they use.* This undervaluing causes them to use gas in activities worth less to them than the real cost of replacing the gas they use. And it discourages users from investing in new technologies even when the gas these technologies would displace costs more to produce than the technologies.

This report examines average cost pricing in detail and then reviews three alternative policy options that might be used to remedy it. Average cost pricing, or "rolled-in" pricing, has been recognized as a problem for some time. A review of the literature, however, revealed that it is often misunderstood. Section II examines average cost pricing in some detail. It provides a conceptual basis for analyzing both the federal and the state regulatory roots of the problem. One by-product of this analysis is a new understanding of the effect that regulatory institutions have on the price series typically used to analyze the gas market. The section closes with some crude estimates of the magnitude of the distortion that average cost pricing causes. The estimates are not particularly robust in the face of changing assumptions, but they all point to a very large distortion.

The remainder of this report examines the three alternative policy options that might be used to reduce this distortion. It uses economic tools to compare these options, where possible illustrating the effect that each has on total national income and on the distribution of income. It gives special attention to the "fiscal equivalence"

of many of them.* The report ranks these options by their effects on national income but cannot choose among them in a definitive way without additional information. It suggests what information on administrative costs and political appeal would be required to choose among fiscally equivalent measures, but does not develop this information. That is left for a later study. The report also tries not to second guess the decisionmaker in the way he would combine these data to make a choice.†

To keep the study manageable, certain limits are placed on the remedies that can be considered. The first and most important limitation is that the regulation of the wellhead price of gas is taken as given. It is important for two reasons. First, it means that the current shortage of natural gas is also taken as given. Because current policy remedies this shortage with a rationing device that gives residential and commercial gas users first rights to whatever gas is available,‡ this study assumes that the shortage does not affect the residential-commercial market for gas. That is a somewhat unrealistic assumption, but more direct consideration of the gas shortage would divert attention from the major issues in average cost pricing itself. Clearly, however, the conclusions of this study *cannot* be applied

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*Options are fiscally equivalent if, except for administrative costs, they have equivalent effects: equivalent generation of benefits (or costs), equivalent transfers among individuals, and so on.

†In a sense, the report represents the first part of what Buchanan (1959) has called a Wicksellian policy analysis. Such an analysis develops policy options as alternative hypotheses that must face the ultimate test: political approval and adoption. The goal of such an analysis is to predict which option will ultimately be adopted and to speed its adoption by clarifying the issues that must be addressed in making the final political decision. There is obviously a thin line between the normative and positive aspects of such a study. No such study can promise to be totally objective, but it can attempt to develop all the information politicians or bureaucrats would find helpful in making their final decision. This study applies some basic tools of public finance to average cost pricing and then attempts to isolate what additional information policymakers would find useful in making their final choice.

‡18 *CFR* at 85 (revised 1 April 1977) defines the set of priorities used to ration gas today.

outside the residential-commercial sector without explicit treatment of the shortage.

Second, whatever remedies we do consider must be able to deal with the multitiered price structure for gas now imposed by wellhead regulation. The growing attractiveness of nondomestic and nonconventional gas sources suggests that multiple prices will probably exist with or without wellhead regulation. But the wellhead regulation itself guarantees not only that they will exist, but that they will be important. Section II discusses the importance of multiple prices in more detail. Again, greater attention to this problem is unwarranted within the scope of this study.

The second limitation that the study imposes is on changing the generic form of rates now used. Pipelines use peak and off-peak charges; most utilities use multiblock tariffs. A strong argument can be made for using multipart tariffs that reflect the long-run and short-run marginal costs of providing gas at both levels. But again, consideration of this option would take us far afield from the task at hand. Whatever gains are claimed from various options are achievable with the basic types of rates now used; a shift to cost-based multipart pricing could probably provide even greater gains. Note, then, that references in the report to "marginal cost pricing" refer not to cost-based multipart pricing but to pricing that reflects marginal costs as closely as possible, *given* that multipart tariffs cannot be prescribed at the utility level. The term "replacement cost pricing" is used synonymously with marginal cost pricing in this sense. Again, Section II discusses this in more detail.

Within these limitations, then, the report examines three policy options. The policy option that first suggested that a study of this kind was required is utility ownership of new technology. It will be easier to discuss this option, however, if we are familiar with two others: marginal or replacement cost pricing and average cost pricing ameliorated by taxes on gas and/or subsidies on substitutes for gas.

Section III describes the replacement cost pricing option. Economists generally prefer this solution, but it involves a large transfer of income from consumers to utilities and pipelines. Hence, Section III examines a number of ways to recover this transfer for consumers,

including lifeline and increasing block rates, gas stamps, and franchise fees or windfall profits taxes on pipelines and utilities.*

Section IV assumes that average cost pricing continues. It first examines the effects of an excise tax on gas, an instrument fiscally equivalent to replacement cost pricing with compensation. It then considers alternative subsidies to substitutes for gas and develops the properties of an "optimal" subsidy under average cost pricing.

Section V finally examines utility ownership of new technology. It uses insights from Sections II and IV to discuss the subsidies inherent in this remedy. It then discusses what types of technologies a utility will choose to own, how this choice affects the markets for these technologies, and what cost advantage utilities have for introducing such technologies.

Section VI sums up the study and weighs the three policy options against the status quo and against one another.

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*One variation of replacement cost pricing not discussed is "incremental cost pricing" in which the cost of obtaining new sources of energy is passed through directly to the consumers whose demand forces the use of these new sources. For a discussion of this form of pricing and current legislative options related to it, see Hederman (1978).

II. THE PROBLEM

The natural gas industry can be conveniently divided into three segments: wellhead producers, transmission pipelines, and distribution utilities. Producers typically sell gas on long-term contract to pipelines who, in turn, sell it on long-term contract to utilities. The problem discussed in this report arises in the regulations applied to the price pipelines charge utilities and to the final price utilities charge their customers. In both cases, regulators seek to limit the profits of "natural monopolies" by forcing them to value their contracts at historical prices instead of current prices. This policy has come to be known as "average cost pricing" or "rolled-in pricing" for reasons that will become evident shortly. Such pricing tends to hold the consumer price of gas below its current cost of production. Consumers are thus encouraged to use gas where its value to them is lower than its cost of production; that is, they are encouraged to waste a valuable energy resource. This section explains this problem in more detail and offers a crude estimate of the difference between the consumer prices that result from regulation and production costs.

The Federal Energy Regulatory Commission (FERC)* controls the prices interstate pipelines can charge utilities for gas. A key feature of this regulation appears to derive from the legal concept of "commingling." It states that gas from various sources becomes commingled in the pipeline and cannot be distinguished, one source from another, by the time that it reaches its destination. Hence if the wellhead prices for gas from different sources differ, a utility receiving gas from the pipeline should pay a weighted average of these prices (plus a capacity and transportation fee, of course) where the weights are proportional to production from these various sources (cf. Breyer and MacAvoy, 1974, pp. 23-24). Wellhead prices do in fact

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*Under the recent reorganization of federal energy functions, this new agency inherited the regulatory responsibilities of the Federal Power Commission (FPC), which formerly regulated the prices that interstate pipelines pay and charge for gas.

differ, again as a result of FERC regulation. Hence, pipelines charge utilities an average price for gas.

This point is important because this average price is likely to be significantly lower than the replacement cost of gas. The reason is that the pipeline buys gas from producers under 15- to 20-year contracts, and older contracts do not reflect the current reservation price of gas, namely, the price required to bring more gas onto the market.* The FERC and the FPC have held down the price of gas from older sources on the assumption that they are inframarginal and will not yield more gas if their price rises above the initial contract price. What adjustment has been allowed has been incomplete. For example, on January 1, 1975, the FPC allowed the price of new regulated gas to rise from $.52/Mcf to $1.42/Mcf, whereas contracts initiated in 1973 and 1974 were adjusted from $.52/Mcf to $.93/Mcf, and older contracts were held at $.52/Mcf (*The Wall Street Journal*, February 28, 1978).† If these were the only sources of gas in a pipeline at the time, the gas price that the pipeline could pass on to utilities would lie between $.52/Mcf and $1.42/Mcf, which would fail to reflect the reservation price for new gas contracts. This raises two questions.

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*The current regulated wellhead price, $1.58/Mcf, probably does not reflect that price either; at present, practically no new gas goes into the interstate market under long-term contract. But gas from foreign sources, fetching anywhere from $1.95/Mcf for Canadian gas to an estimated $3.25/Mcf for Algerian liquefied natural gas, does. About $2.25/Mcf brings gas onto the unregulated intrastate market, the probable reservation price for American gas. This is consistent in the ERDA's Market Oriented Program Planning Study (MOPPS) estimates. And synthetic gas costs $2.73-$3.69/Mcf. As we shall see in a moment, however, the reservation price is likely to be higher under wellhead price regulation than in its absence. These prices come from FPC *Opinion 770-A*, November 1976, p. 114 (Canadian and Algerian); "Gas from Canada May Get More Costly," *Energy Daily*, May 5, 1977 (intrastate gas); "1001 Years of Natural Gas," *The Wall Street Journal*, April 27, 1977 (MOPPS); ERDA-MOPPS ("second generation" synthetic gas); and "Gas Price Boost Is Left Standing By High Court," *The Wall Street Journal*, February 28, 1978 (regulated rate).

†"Mcf" is "thousand cubic feet" of gas. Two other commonly used measures of the quantity of gas also appear in this report. Because a standard cubic foot of gas contains 1020 Btu's of energy, 1 million Btu's, or MMBtu, is used interchangeably with Mcf. And a quad is 10^{15} Btu's.

First, suppose a utility asks a pipeline for additional delivery of gas. The pipeline must pay the reservation wellhead price for new gas to cover this addition, but cannot pass through the full reservation price to the utility. Why would the pipeline be willing to enter a contract in which the price it receives is lower than its marginal cost of fulfilling the contract? The answer lies in regulation: the pipeline cannot charge the full wellhead price to the utility that forced the pipeline to buy the new gas, but it can pass on to its other customers that portion of the cost of new gas that the utility in question does not pay for. They pay an averaged price for gas, and because the average price in the pipeline rises with the new contract, everyone pays a higher price.*

Note that whereas the pipeline can recover the full cost of new contracts, individual utilities do not recognize the full cost of the gas. This puts them in the position of presenting the pipeline with an excessive derived demand for gas, which benefits both the pipeline and the utility. The reason is that the profits of both are restricted to being the product of an "allowed rate of return" fixed by regulation and a "rate base" determined by the capacity of the system.† *Given* this regulatory structure, anything that allows the utility or pipeline to expand its rate base allows it to expand its profits.‡ The averaged price increases demand for gas and hence is likely to increase the demand for additional capacity as well. *Given* the form of profit regulation, then, pipelines and utilities probably find the average cost pricing of gas quite attractive.**

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*This appears to be an extreme case of Peltzman's theory of cost sharing in publicly owned producers of private goods. (Peltzman, 1971.)

†For details, see Kahn (1970, 1971) or Breyer and MacAvoy (1974).

‡This is the basic thesis provided in Averch and Johnson (1962) and Wellisz (1963) and reviewed in Baumol and Klevorick (1970). See these studies for the explicit assumptions associated with the notion. Joskow (1974), McKay (1976), and others have raised doubts about the effectiveness of regulation in the past, but the current inflationary regime seems to ensure a sufficiently frequent review of profits.

**This applies to the regulation of the structure of gas prices as well. Regulators require pipelines to use a two-part tariff in sales to utilities, the first or "demand" part serving effectively as

The second question average cost pricing raises involves the relationship between the current reservation wellhead price for a long-term contract and the current replacement or opportunity cost of gas. With regulatory restrictions on price escalation during the life of a contract, there is no reason to think that they will be the same. Producers must recover the opportunity cost of gas over the life of a contract in any price they contract for; if they assume that gas prices will rise over the life of a contract, and that they will not be allowed to fully adjust the contract price to allow for this rise, their reservation wellhead price for long-term contracts will exceed the replacement cost of gas. Figure 1 illustrates this point.

Assume that all contracts last 20 years and that no price adjustment is allowed. Assume further that the real marginal cost of producing gas (net of inflation) has been rising and is expected to rise 5 percent a year and that the real discount rate (net of inflation) has been and is 8 percent. Consider a producer at time t = 0 determining the constant price, P_0, he must charge to just recover the opportunity cost of his gas in each period, C_t, over the next 20 years. He will require

$$\int_0^{20} (P_0 - C_t)\, e^{-.08t}\, dt \geq 0 \ .$$

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a surcharge on peak-load use. Many criteria are used to allocate costs between the two parts of this tariff, but in the end the application is rather ad hoc (Breyer and MacAvoy, 1974, pp. 33-38). Thus, many pipelines are probably left free to use average cost pricing of gas to subsidize their peak surcharge, which affects the derived demand for capacity more directly than would a subsidy of the second or "commodity" part of the tariff. (See Wellisz, 1963.) Only a careful analysis of individual contracts could confirm this fact. Utilities, on the other hand, use a declining block tariff, which is invariant with respect to total capacity utilization. Customers with various contributions to peak (and hence capacity) demand are distributed across any block rate structure. Utilities presumably attempt to imbed the subsidy implicit in average cost pricing in a way that maximizes demand for capacity subject to the constraint that revenues cover costs and allowed profit. Some of the considerations involved in this nontrivial task are presented in Goldman, Leland, and Sibley (1977), Leland and Meyer (1975), and Spence (1975). Again, only a careful analysis of individual contracts can shed more light on this problem.

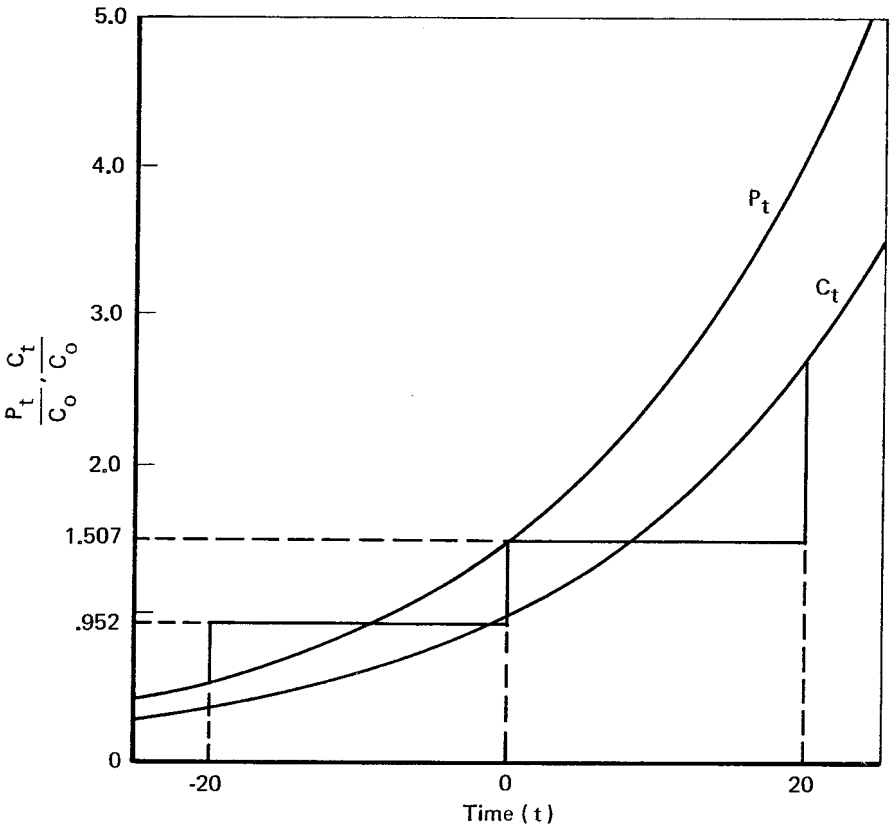

Fig. 1—Contract price (P_t) and spot price (C_t) when escalation clauses are prohibited

This calls for a contract price of at least 1.507 C_0.* If producers make this decision each year to set their reservation prices, we will observe a set of contract prices 1.507 times greater than the replacement cost in each period. That is, recent contract wellhead prices are *not* a good measure of current replacement cost. But an average might be.

If we assume that consumption of gas has been constant over the last 20 years, then we can take a simple average of P_t over the time period t = -20 to t = 0. This yields an average price of .952 C_0,

*$C_0 = C_t$ when t = 0. The contract price is obtained by using $C_t = C_0 \exp(.05t)$, setting the integral equal to zero and solving for P_0.

only 5 percent different from the current replacement cost of gas. If we had assumed growing consumption, the average might be even closer. Allowing escalator clauses would lead to a smaller divergence of contract prices for gas being used at any given time, but would not change the basic logic of our illustration. We cannot simply dismiss an average cost-based price, then, as a good indicator of the replacement cost of gas. But a serious problem remains.

Our simple model assumes that expectations are fulfilled. But the price of gas has risen very rapidly over the last two decades. Any time the price of a commodity rises faster than the rate of interest on investments of similar risk,* the price rise must have been unanticipated. And there are good reasons to believe it was. The OPEC embargo accelerated gas prices faster than expected by encouraging conversion from oil to gas and thereby increasing demand for it. Environmental objections to coal had a similar effect. Price controls on gas are now aggravating this problem by forcing gas utilities to turn to expensive foreign sources sooner than expected. And general inflation and inflation of equipment costs have been more serious than anticipated.

In the face of such unanticipated price escalation, long-term contracts with limited escalation clauses will not recover the opportunity costs of the committed gas actually experienced. For a given time path of costs, this reduces the contract prices for older contracts below what they would have been if the actual time path had been fully anticipated; the average cost measure of price falls. Further, FERC does not have the authority to regulate gas contracts from the many foreign sources that become viable at higher prices. Thus, foreign producers will probably anticipate full escalation clauses and contract for gas near its current opportunity cost. This further reduces the average cost measure of price. In sum, these complications in our basic model do not eliminate the gaps between initial reservation prices and concurrent opportunity costs, but they mitigate their

*By similar risk, I mean similar uncertainty about the future benefits of both investments. Uncertainty about an investment in gas futures--through an organized market or by actually holding the commodity in the ground--involves the distribution of subjective probabilities attached to various future price paths.

effects. Average cost pricing of gas in the pipelines still leads to a gap between the replacement cost to utilities and that to producers.

The effects of pipeline regulations are exacerbated by state regulation of individual utilities.* The commingling concept is applied again here, forcing each utility to average the costs of all of its gas contracts. These include FERC-regulated contracts from different pipelines, as well as certain unregulated emergency contracts and contracts for synthetic gas. Both of these latter contracts are short term. Emergency contracts allow utilities to compete with demanders in the unregulated industrial and intrastate markets in what is effectively a spot market for very short periods. Synthetic gas--internally produced or purchased--is used in some utilities to meet short-term peaks. Averaging the prices of these contracts, which are likely to reflect the real replacement cost of gas, with those from the underpriced regulated contracts further contributes to the differential between the price that final consumers pay and the real replacement cost of gas.

We are faced once again here with a company--this time the utility--selling gas to consumers at a lower price than its replacement cost to the company. And this practice is viable for the utility for the same reason that it was viable for the pipeline: all the utility's customers share the cost of new gas contracts required to supply any one of them. As noted before, the utility finds effective subsidization of new gas contracts with older and cheaper ones attractive if it allows the utility to lower price and increase demand for its capacity. The problem of anticipatory contracts does not arise here because the pipeline can anticipate price adjustment through a fuel cost pass through.†

In the end, a residential or commercial consumer pays a weighted average of the contract prices for all gas flowing into the utility

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*Kahn (1970, 1971) provides a detailed discussion of the institutions associated with these effects and other aspects of regulation. This section concentrates on the conceptual aspects of these effects.

†This is particularly true in the current inflationary regime in which regulators are attempting to reduce administrative review costs by allowing dollar for dollar fuel cost pass through. (See Joskow, 1974.)

supplying the consumer. These weights are proportional to the flows of production from each source. The contract prices going into this average from unregulated sources--foreign, emergency, and synthetic--closely approximate the opportunity cost of providing these sources of gas. The contract prices for regulated sources--primarily domestic production under long-term contract--reflect the initial reservation price for these gas contracts partially adjusted upward by the FERC for cost escalation. They may be greater than or less than the current opportunity cost of gas, but on balance they fall significantly below it. In the end, then, residential and commercial gas consumers base their replacement cost of gas on a quoted price that significantly undervalues the gas they use. This is the distortion that concerns us.

How serious is the distortion? The anticipatory effects in long-term regulatory contracts, and the incentives that profit regulation gives utilities and pipelines to arrange their rate structures, make this question hard to answer.* But by making some heroic assumptions, we can determine the order of magnitude of the distortion. The estimation difficulties revolve around the current opportunity cost of gas and how utilities and pipelines split costs between marginal or off-peak price and inframarginal price or peak surcharge. The first can be resolved by considering various estimates of the current cost of producing natural gas. It can be argued that this is not the real opportunity cost of gas, because regulation has led to inefficient production of the gas now used and inefficient allocation of the gas produced to various uses. *Given* these distortions, of course, saving 1 Mcf of gas saves the production cost of that gas or its equivalent for imported gas. Hence, the current replacement cost of gas is a useful number. And we will take these other distortions as given in most of what follows (cf. Besen and Mitchell, 1977). Nonetheless, it would be nice to have a measure that would not change much if the gas market were significantly deregulated. This reasoning makes $2.25/Mcf

*See the fourth footnote on p. 7 for an elaboration of this second point and references to several conceptual studies that examine this problem.

an attractive estimate of opportunity cost. It is close to the current production cost for unregulated gas in the intrastate market and also to the price that a study group in the Energy Research and Development Administration (ERDA) felt would put the United States "awash" in domestic natural gas.* If ERDA is correct, this price would prevail even if demand for gas changed significantly with deregulation of wellhead prices.† An alternative gas source often mentioned by more conservative observers of the gas market is liquefied natural gas (LNG), which would cost $3.25/Mcf at the port of entry. We will use these two estimates to bracket our estimate of the distortion. Note that neither suffers from the anticipatory effects of regulated contracts.

The second problem is more difficult. The FERC sets pipeline prices in two parts: a commodity charge, which acts as an effective off-peak price, and a demand charge, which provides a peak surcharge. That is, pipelines use peak-load pricing.‡ The levels of these charges differ from one pipeline to the next and within a pipeline for utilities at different locations along the pipeline. Utilities, on the other hand, typically use a declining block tariff that is stable in the face of changing capacity utilization. The rate is typically presented as a way to capture capital costs inframarginally while charging short-run marginal cost at the margin, but consumers typically demand levels of gas over the whole structure. Consumers with small demands, then, usually face a higher marginal price or replacement cost for gas than consumers with large demands. And the structure of the tariff differs from one utility to the next.

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*See the first footnote on p. 6 for the sources of this estimate and those for alternative gas sources.

†Deregulation would raise prices, tending to reduce demand. But it would also increase supply and draw users of alternative fuels back to gas as a cheap fuel relative to alternatives, particularly electricity. As suggested earlier, this report makes no attempt to define or describe an unregulated future.

‡This pricing is not necessarily cost-based and hence the preferred type of multipart pricing mentioned in the Introduction. See the fourth footnote on p. 7 for some details and other references on the pipelines' peak-load pricing and utility multiblock pricing.

For simplicity, assume that all final consumers face the same utility declining block rate structures and pipeline two-part tariffs. An upper bound on the marginal distortion emerges if we assume that (a) pipelines include only the cost of gas in the off-peak charge; (b) all residential and commercial consumers fall into the lowest block of utilities' multiblock tariffs; and (c) all utilities charge only the pipeline commodity charge in the last block. A lower bound will result if we assume that (a) pipelines cover all costs in the commodity charge, leaving only a nominal peak surcharge; and (b) that utilities charge the same marginal price in all blocks of their tariff, leaving only a nominal multiblock tariff. Note that this last assumption provides a measure of the percentage distortion in the total price charged under either set of assumptions.

The average retail price of gas varies considerably by region, of course. The average residential gas rate in July 1976 was about $2.00/Mcf (FPC *Opinion No. 770-A*, 1976, p. 122). Of that, the wellhead price was about $.50 and all other costs were about $1.50.* The relevant marginal price for our upper bound, then, is $.50/Mcf, and that for our lower bound is $2.00/Mcf. The difference, $1.50/Mcf, can be used to adjust the wellhead replacement costs above to retail prices of $3.75 and $4.75, respectively, for the ERDA and LNG estimates. Table 1 summarizes the range of our distortion estimates under different assumptions.† Our estimate of the distortion is obviously not very

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*These costs are based on a synthetic breakout of wellhead and other charges. A survey of fourteen major markets in 1971 found that of a typical retail price for gas of $1.20, about $.23 went to producers, $.71 for distribution, and $.26 for other charges, primarily transportation from producer to utility (Foster Associates, Inc., 1974, p. 252). Adjusting them for price changes from 1971 to 1976, the breakout becomes $.50 for wellhead price, and $1.10 and $.40 for distribution and other costs. The wellhead price approximates the wellhead ceiling of $.52 in 1976. The acceleration in distribution and other costs reflects the measured change in prices from 1971 to 1976. Wholesale prices for machinery and equipment changed 48 percent during the period; the wholesale price index rose 60 percent (see the *Survey of Current Business*). They sum to the average retail price for gas in 1976, $2.00.

†The first column compares the current hypothesized marginal price, $.50/Mcf, with the projected prices. The second column compares current and projected full prices.

Table 1

ESTIMATES OF THE PRICE DISTORTION ASSOCIATED WITH AVERAGE COST PRICING

Cost	Marginal Price Is Wellhead Price	Marginal Price Is Average Price
ERDA ($3.75)	$1.75 (350%)	$1.75 (88%)
LNG ($4.75)	$2.75 (550%)	$2.75 (138%)

robust, but whatever estimate we choose, it is large. The average price distortions are the more important for long-term decisions concerning the purchase of gas appliances and homes or offices with gas space and water heating. The price distortion relevant to consumption of gas from a fixed set of appliances lies between the numbers in the first and second columns. If consumers all truly pay the wellhead price as the marginal retail price, the relevant distortion runs on the order of 350 to 550 percent. As other components are added to the marginal retail price, the distortion falls toward the prices in the second column; these prices offer a lower bound on the marginal distortion.

In sum, average cost pricing, or rolled-in pricing, of gas results from the profit regulation of pipelines and utilities coupled with the price regulation of wellhead prices. These regulations lead to a price on the order of one-half the actual costs of producing new gas. And if we look at the marginal price of gas used to make decisions about the intensity of use of existing gas appliances, the price that consumers perceive may be as little as 15 percent of the actual cost of providing the gas they use. This effective subsidy to gas induces consumers to use currently existing gas appliances too much and to overinvest in new gas appliances. That is, gas is used in many applications where other options have a lower social cost. Those include "traditional" sources--electricity, coal, fuel oil--and "new"

sources--solar, heat pumps, thermal storage, insulation--as well.* Alternative forms of regulation and pricing should be able to eliminate some of these distortions. We turn to three of them now.

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*Note that direct Btu comparisons among technologies are not always fruitful, even when adjusted for efficiency. Electricity, for example, is more expensive than gas in most areas, even at the marginal costs we have posited. The winter price of gas, for example, would have to approach $9.00 in Boston or $12.40 in New York before electricity would look more attractive on a straight Btu basis (Bennington, Bohannon, and Speivak, 1976, p. A-5). And yet, electricity is an important source of space heating in these cities. Btu comparisons are as difficult for new technologies as for traditional ones. Differences in capital costs, perceived safety, and so on contribute to the difficulty. A modal choice model like the one in Hirst, Lin, and Cope (1976) or Baughman and Joskow (1976) makes more sense. It captures the niches and individual idiosyncracies that lead to substitution over a wide range of prices.

III. OPTION 1: ELIMINATION OF AVERAGE COST PRICING

Average cost pricing is the primary culprit in this problem; eliminating it would eliminate the problem. Presumably, average cost pricing would be replaced by marginal cost pricing. All gas sources would be given the same imputed value regardless of the current price paid for such gas. This raises two basic problems.

First, since the cost of the highest cost unit of gas used in a period sets the price for all units, a utility or pipeline may attempt to circumvent regulation by using inordinately expensive gas at the margin. Oil producers achieved this circumvention, with state and federal government cooperation, under prorationing regulations and the import quota.* A utility or pipeline could achieve it relatively easily without cooperation; only PUC or FERC acquiescence or neglect is required. The extensive regulations and control now used to supervise average cost pricing should be up to the task of verifying the legitimacy of cost claims. In sum, the problems of inflated marginal costs are real but manageable.

Second, the price rise that would follow the replacement of marginal cost pricing would induce an immediate transfer from consumers to utilities and pipelines. If current intrastate wellhead prices provide a reasonable estimate of the marginal cost of gas at the wellhead, and if, for example, demand is highly inelastic, marginal cost pricing would transfer $1.75 from consumers to utilities and pipelines for every thousand cubic feet of gas consumed.† For a typical household consuming 120 Mcf per year, it would mean a transfer of $210 per year to the utility and pipelines.‡ A utility and its suppliers

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*The import quota effectively gave U.S. producers a national franchise, and prorationing restricted production of low-cost oil in favor of high-cost oil. The end result was a higher than competitive price and large rents on inframarginal oil for the owners of oil rights. (See Adelman, 1964.)

†This assumes that capital charges are not changed.

‡The average household consumed 120 Mcf of gas in 1975 (FPC *Opinion No. 770-A*, November 1976, p. 122).

serving 500,000 households would receive $105 million a year over and above current costs and allowable profits. The wealth of stockholders in the utility and pipelines would increase by several times this amount, since anticipated increased revenues would be capitalized into the value of their stock.

These figures are upper bounds on the size of long-run transfers, because the demand for gas is not highly inelastic. The demand for space heating alone has been estimated to be at least -.3 in the long run.* And if alternatives to gas may be used for space heating, the long-run elasticities rise with interfuel substitution. Estimates based on historical data suggest elasticities of -1.0 or more.† They will rise further as new technologies such as solar and heat pumps approach competitiveness. The higher (in absolute value) the demand elasticity, the greater the impact of a shift to marginal cost pricing on the quantity demanded.

A hypothetical example will help to illustrate these arguments. Figure 2 shows the national demand for space heating (D_{sh}), the marginal cost of producing gas at the retail level (MC_g), and the average variable cost of providing gas at the retail level (AC_g).‡ Capital

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*Nelson (1975) finds a long-run elasticity of -.3. Stout (1961) finds a short-run elasticity of -.3, implying a higher long-run elasticity.

†Baughman and Joskow (1976, p. 316) reference estimates ranging from -.4 to -2.7. Thus, -1.0 is as reasonable as any.

‡Aggregating from local market areas to a national market presents serious aggregation problems. For a discussion of these difficulties in an analogous context, see Ippolito and Masson (forthcoming). Because this is meant *solely* as an illustration, these problems are not treated seriously here.

The demand curve is defined under some rather arbitrary assumptions. (a) Each utility is assumed to use the total price of gas it pays its supplier-pipelines as the price in its final block. Data presented in Section I show this to be $.90/Mcf currently. (b) All consumers are assumed to face the same price in this block and to consume gas in this block. This condition is assumed to hold in the face of changes in this price. (c) Changes in the inframarginal capital charges, currently $1.10/Mcf, are assumed not to cause consumers to enter or exit the gas market (cf. Wenders and Taylor, 1976). Without these assumptions, demand could not be defined as a function of one price; it would be a functional of the individual rates consumers face and

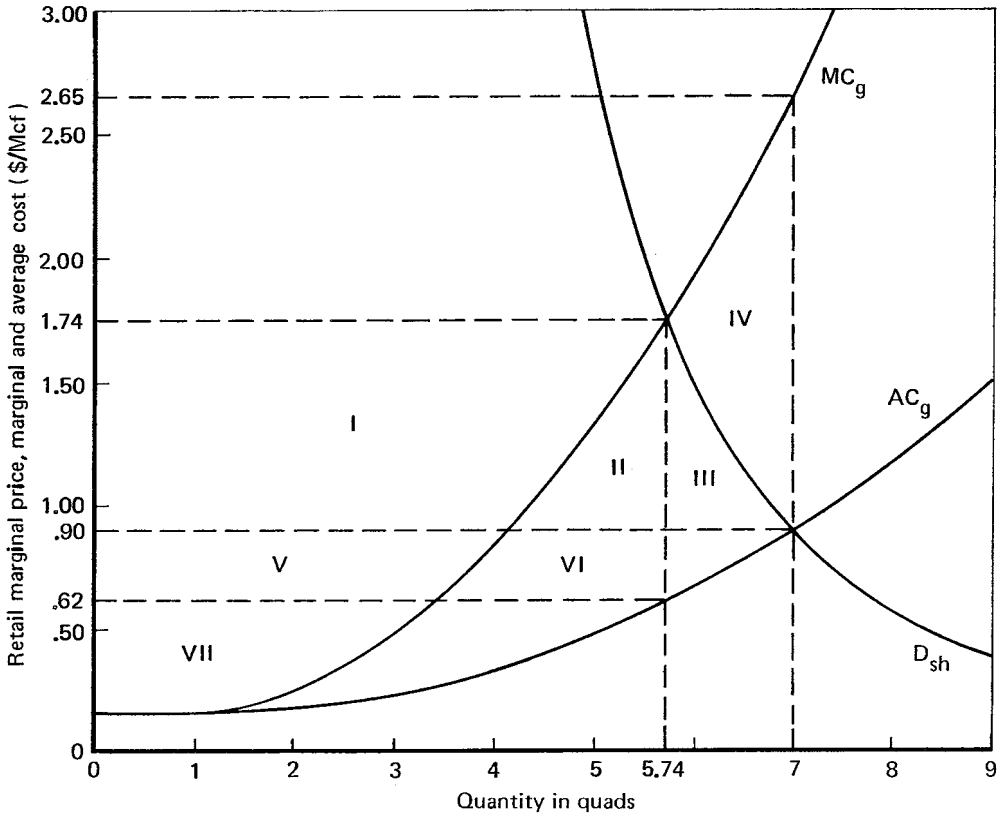

Fig. 2 — Simplified market for gas space heating, with average cost pricing

costs are assumed to be covered by inframarginal charges that do not affect marginal choice; they are simply transfers from consumers to utilities.* The curves shown are *purely hypothetical*. But they are chosen to reflect certain aspects of our current situation. Equilibrium

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their individual demand functionals. (See Leland and Meyer, 1975.) For simplicity, income effects are assumed to be negligible.

The marginal cost curve is not a classic cost curve; instead, it reflects the current prices paid for all contracts for gas that would have to be used to achieve a certain level of gas use. The average cost curve is derived from this curve to show what marginal *price* regulators would prescribe, given the set of contracts reflected in MC_g.

*The inframarginal charge can come in the form of a customer charge, which is effectively an entrance fee, or a series of inframarginal blocks. In reality, a customer charge is the only kind of fee that will not affect marginal consumption of gas. We will not consider that here.

occurs at a national consumption level of 7 quads and a marginal price of $.90/Mcf. An additional $1.10/Mcf (not shown) is collected inframarginally to cover capital costs. The retail marginal cost of gas at this level of use is $2.65. Demand for space heating displays a constant elasticity of -.3. (No interfuel substitution is considered.) Because the example is purely hypothetical, issues of short term, long term, and transition are not addressed.

In this example, a move to marginal cost pricing would reduce gas use for space heating by 1.26 quads, or about 18 percent. The marginal price of gas would rise 94 percent to $1.74/Mcf. The marginal cost would fall 34 percent, causing average cost to fall 31 percent to $.62/Mcf. The lower level of consumption requires a higher per-Mcf capital charge to finance a fixed capital stock; this increases from $1.10 to $1.34.* Total average costs are then $1.96/Mcf. Hence, a marginal price of $1.74/Mcf will recover all but $.22/Mcf of costs. If inframarginal charges of $1.10 continue after the shift to marginal pricing, utilities and pipelines will receive $.88/Mcf or $5.05 billion in excess of costs and allowable profits.

It is this kind of transfer from consumers to utilities and pipelines that appears to concern consumers and regulators about the use of marginal cost pricing. But it is relatively easy to show that some set of subsidies exists that can avoid this transfer and make consumers, as a class at least, as well off after the move to marginal cost pricing as before.† In our example, the move to marginal cost pricing costs

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*The 18-percent drop in consumption means that the inframarginal charge must increase by 1/(1 - .18) or 1.22. Note that, contrary to the discussion in Section II, the capital stock is not varied here with the level of output. Variation would occur in the long run, but regulation allows a utility on pipeline to continue to charge against an existing capital stock until it depreciates. The charge on capital will not fall with output, then, in the short run.

†The regions in Fig. 2 denoted by Roman numerals can be used to demonstrate this point. We can ignore fixed capital assets in this analysis, since consumers pay the same total amount for them with or without marginal cost pricing. The move to marginal cost pricing effectively extracts an amount from consumers equal to the areas of I, II, and III; this is the consumers' surplus that is eliminated by the price rise. Utilities and pipelines, on the other hand, gain an amount

consumers $5.35 billion.* But a full move to marginal cost pricing would give gas suppliers a surplus of $1.12/Mcf or $6.43 billion.† They could make consumers about $1.08 billion better off without suffering from the change. This $1.08 billion is the social gain--the increase in national income created by the change--that makes a move to marginal cost pricing politically attractive. It creates new income for politicians to hand out. One simple way to distribute this surplus in this example is to choose a new inframarginal charge between $.22/Mcf, which transfers the full amount to consumers, and $.41/Mcf which lets the suppliers keep it all.‡

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equal to areas I, II, V, and VI. This amount is the inframarginal profit generated by the change; no such profits were allowed before the change. The question of whether utilities and pipelines can compensate consumers, then, comes down to one of whether areas V and VI together exceed area III. They do. To see this, note first that by the definition of the average variable cost curve, area VII equals areas II and VI combined. Similarly, areas V and VII together equal areas II, III, and IV. These two conditions imply that area V equals areas III and IV less area VI. Or equivalently, areas V and VI together exceed area III by an amount equal to area IV. Area IV represents the amount that will be gained by society as a whole in the move to marginal cost pricing. It is, of course, a familiar "Harberger triangle" (Harberger, 1971). Its existence is not dependent on the circumstances in our example. It ensures that utilities and pipelines can compensate consumers at least enough to make the consumers *as a class* better off with than without marginal cost pricing.

*Areas I, II, and III in Fig. 2; see the previous footnote for an explanation.

†This amount differs from the $5.05 billion transfer mentioned earlier, because we assume that a "full" change would also adjust the inframarginal change from $1.10 to $1.34.

‡It may be useful to suggest how this solution compares with a marginal-cost-based, peak-charge solution. The solution in the text could well be appropriate if the reduction in demand in the example left the utility with no capacity constraints. We would then want to collect capital charges (to keep the utility financially viable) without disturbing the perceived short-run marginal cost of gas represented in the marginal cost. Of course, in spite of our assumption to the contrary, some small consumers will experience part of the capital charge as a marginal price. Hence, the final block of the rate structure should include a portion of the capital charge, suggesting that real world inframarginal surcharges would recover even less than the $.22 to $.41/Mcf suggested. With seasonality of demand in which capacity continued to constrain some demand, of course, capital costs would be appropriately recovered in some seasonal surcharge on the marginal price.

The real concern today appears to be that a shift to pricing gas at replacement cost would raise revenues so much that inframarginal surcharges would have to be negative to maintain equality between revenue on the one hand and cost and allowed profits on the other. This suggests the use of an inverted block rate where the first few Mcf of gas are purchased at a low, perhaps negative, price. (Of course, negative prices may prompt some persons to call themselves gas consumers simply to get the transfer.) Succeeding blocks offer gas at higher and higher rates. The "lifeline" rate is a variation of the inverted block rate in which some subsistence level of gas is offered at a low price and purchases beyond this amount occur at higher prices. Ideally, such a rate would be designed to have all consumers demand enough to pay the marginal price in the last block, and this price would be set at the short-run or long-run price of gas, as required to ration existing capacity.

In reality, not everyone will consume an amount that places them in the last block of the tariff. Some consumers will end up consuming amounts of gas that present them with a lower marginal price than that in the last block. What is the point of setting price equal to marginal cost in the final block if not everyone consumes in that block? The principles of "Ramsey pricing" suggest that a more reasonable form of pricing is possible.* Ramsey prices meet a revenue constraint by

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*Assume either that (a) the benefits and costs of policy changes for everyone in the economy can be weighted equally, or that (b) it is costless to transfer money from one person to another. Then Ramsey (1927) shows that given a revenue constraint, total net benefits are maximized by allowing the price each person pays for a good to diverge from the marginal cost of producing that good in inverse proportion to the person's elasticity of demand for the good, i.e., his willingness to adjust his consumption as its price changes. This result does not apply if these assumptions are inappropriate. And, in fact, a revenue constraint is not really required for utility pricing if the assumptions for Ramsey pricing hold. But even if they do not hold, a variation on Ramsey pricing is appropriate. If the policy relevance of benefits and costs varies by individual and transfers are costly, it would be appropriate to allow higher prices for unfavored consumers and lower prices for favored consumers than Ramsey pricing would allow. The divergence from Ramsey pricing would rise as the differential treatment of individuals or the cost of transferring income rose. Nonetheless, the Ramsey price is a good place to start, and the basic principles it embodies are valid with or without the assumptions above.

setting prices that increase everyone's consumption by the same percentage (Baumol and Bradford, 1970).* Because small users of gas are typically thought to be less responsive to price changes than large users, a substantially larger reduction is required in the marginal price they face than in the price larger users face; such pricing induces everyone to increase consumption by the same percentage. A lifeline or inverted block rate is one way to achieve such prices. Leland and Meyer (1975) discuss the connection between block prices and optimal pricing in detail. Ramsey pricing, then, calls for a rate reduction for all users; the marginal price should be less than marginal cost.†

A divergence between marginal cost and price remains. Can we be sure that this arrangement is more desirable than average cost pricing? Note that average cost pricing is simply one more variant of pricing subject to a revenue constraint. Ramsey pricing could lead to a price structure very similar to average cost pricing if large users of gas were less responsive to price changes than small users. But the evidence strongly points the other way.‡ Some inverted rate structure

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*The easiest way to apply Ramsey pricing is with a customer charge that distorts only entry choices and not marginal consumption. Small adjustments in revenue are easily made by changing the entry fee. But it suffers from two problems. It does change the participation and hence consumption of small users, thereby violating the equal percentage goal. And to shed excess revenues, a negative customer charge is required, a charge that may be unacceptable.

†That may not be true if smaller users are in substantially greater favor than large users and transfers are costly. In this case, the subsistence rate on inframarginal gas would be lower than the Ramsey rate, and the marginal price would be higher. The marginal price might equal or even exceed marginal cost.

‡If large users were relatively unresponsive, a larger divergence between price and cost would be required at high levels of use than at low levels to encourage the same percentage increase in use at all levels. When marginal cost exceeds average cost, this could lead to a pricing structure in which, by coincidence, the marginal price equaled the average variable cost of providing gas. But again, it appears that large users are more responsive than smaller users.

Note also that when average total cost exceeds marginal cost, the unresponsiveness of small users makes the declining block structures we now typically observe look reasonable. That is, if Ramsey pricing is

will increase national income over that under average cost pricing, even if not by as much as would a move to marginal cost pricing.

But even if an increasing block tariff could be designed that would cause all consumers to face the real replacement cost of gas, a problem would remain. Such a tariff, in essence, would charge all consumers the replacement cost of gas and then give them a lump-sum transfer to compensate them for the increased cost of gas. Just as a negative initial price draws consumers with no intention of using gas, this lump-sum transfer draws consumers who wish to use gas in an activity whose value is less than the replacement cost of the gas. For example, the decision to occupy an all-electric or all-gas home would depend in part on the effective subsidy created by an increasing block gas rate if one chose the all-gas home. In this home-purchase decision, this "inframarginal subsidy" becomes a subsidy at the margin.* A numerical example may help to clarify this point.

Consider a household's choice between using gas and using electricity for space and water heating where electric thermal storage is available and time-of-day pricing is in effect for electricity. Suppose, for simplicity, that demand is inelastic, so that the household will demand 72 million Btu's of space heat annually.† Suppose, in addition, that the gas company provides 60 MMBtu's a year at $1.00/MMBtu and any additional gas at $3.00/MMBtu, the real replacement cost of gas. Thermal storage permits the use of off-peak electrical power at $1.00/MMBtu, but requires installation of additional equipment

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the actual criterion used for pricing--and I do not want to suggest here that it is--a switch from declining block to inverted block rates in response to a switch in average and marginal costs is entirely appropriate. (Block rates, of course, are not the only option available.)

*Note that a declining block rate suffers from precisely the same problem: inframarginal surcharges act as a tax in decisions that involve the all-or-nothing choice implicit in the purchase of a home or even an appliance. The distribution of capital surcharges--positive or negative--must be completely arbitrary in the sense that they are not based on a consumer's contribution to the peak use of the capital. (Cf. Turvey, 1963.)

†With an energy efficiency for gas of 60 percent, this level of consumption is consistent with the estimate offered earlier that the average household consumes 120 Mcf a year.

amortized at $250 per year. Assume energy efficiencies of 60 percent for gas, 90 percent for electricity, and 100 percent for thermal storage.* In all other respects (capital costs, safety, reliability, and so on), let the systems be equivalent. The annual costs of the two alternatives will be $240 for gas and $330 for electricity. Gas would be preferred. If, on the other hand, we had relied strictly on replacement cost pricing, the annual costs would be $360 for gas and $330 for electricity.† Here gas would be preferred only if the efficiency of thermal storage were significantly less than the 100 percent postulated. In sum, the inframarginal subsidy to gas becomes a subsidy on the margin when we make capital choices. In this case, it has distorted the market. Similar distortions between gas and other fuels will also occur.

Both of these difficulties of block rate--distortions in current use and in investment decisions--can occur if new technologies significantly reduce the use of gas in a household. For example, consider the joint use of insulation and solar in a typical house. Assume the same block tariff and initial energy use we assumed in the last example. Efficient insulation reduces the need for energy in a typical house about 35 percent (CBO, 1977, p. 87). In our previous example, then, the need for delivered gas would fall from 120 MMBtu annually to 78 MMBtu. (See Fig. 3.) The household will value all the gas saved at $3.00, its replacement cost, and hence make the socially correct

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*Asbury and Mueller (1976, p. 7) use this price of electricity, equivalent to about $.01 per kilowatt-hour, in their analysis of thermal storage. $250 is lower than most estimates of the annualized cost of thermal storage and is used only for illustration. See Asbury et al. (1976, pp. 33ff) for more realistic estimates. Bennington et al. (1976, p. A-4) provide the efficiencies of gas and electricity. The difference in rate structure for gas and electricity is used for illustration, but is not unrealistic given that gas is more easily stored than electricity.

†Under the gas system with block pricing, the first 60 MMBtu's cost $60 and the next 60 cost $180 for a total of $240 (equivalent to the cost under current pricing, which averages $2.00/MMBtu). With all gas priced at $3.00/MMBtu, this becomes $360. With electricity, 80 MMBtu must be delivered to provide 72 MMBtu of space heating, at a cost of $80. One hundred percent efficient thermal storage amortized at $250 annually implies an annual cost of $330 for electricity.

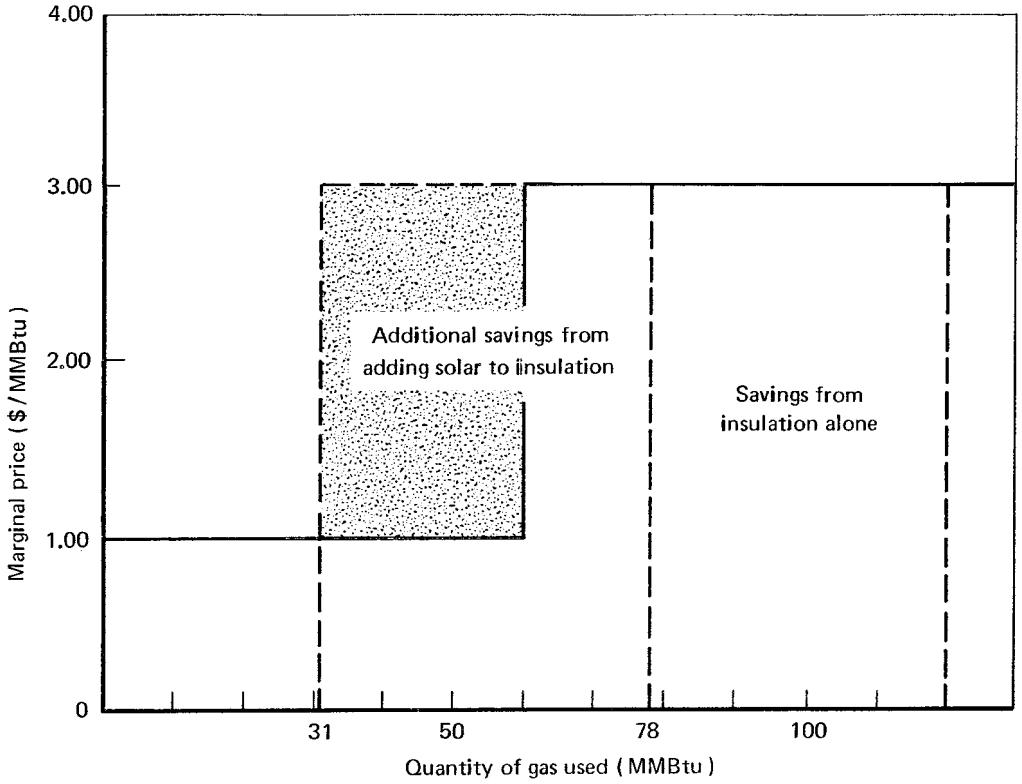

Fig. 3—Effect of an increasing block tariff on valuation of new technologies

decision about whether to insulate. But now suppose the household also contemplates adding a solar space heater. These typically replace only a fraction, say 40 to 60 percent, of the fuel used for heating. A solar heater replacing 60 percent of energy needs would reduce the need for gas to 31 MMBtu. Here the marginal price of gas is now $1.00. While the social value of the gas saved by the insulation and solar heater jointly is $3 × 89 = $267, the household values it at only $209. The shaded area in Fig. 3 accounts for the difference. And the household now values additional units of gas at $1.00, not the marginal cost of $3.00. That is, the block pricing gives homeowners smaller incentives (a) to insulate and adopt solar and (b) to conserve gas used in existing appliances than we socially desire. The addition of heat pumps and thermal storage could reduce the use of gas still further, thereby also further reducing the incentives for a socially acceptable use of energy.

An alternative approach is to charge the replacement cost for all gas but issue exchangeable "energy stamps" which reduce the cost to the bearer of some particular number of Mcf's of gas. In terms of our example, each household would receive stamps allowing it to purchase 60 Mcf of gas at $1.00 each. If the household needed less than 60 Mcf, it could sell the remaining stamps. If $3.00 were the replacement cost of 1 Mcf of gas in the market, the household could count on receiving $2.00 for each Mcf stamp on the market. That is, handing out exchangeable stamps for 60 Mcf of gas is equivalent to handing out $120.00 in cash to each household. This equivalence will hold true so long as (a) a household's right to stamps does not depend on its use or level of use of gas, and (b) the stamps issued do not entitle holders, taken together, to more gas than a utility would provide at the price guaranteed by the stamps. This requires that stamps be utility specific. It also requires a mechanism for transferring rents from pipelines to utilities so that they may be passed on to the consumers. A stamp program could be used at the utility-pipeline interface as well.*

Implemented properly, no margins are distorted and, for better or worse, stamps make the inframarginal subsidy explicit. Note also that whereas energy stamps present households with new wealth, the government does not provide this wealth from its own coffers; the stamps transfer all wealth created from pipelines and utilities to households. Hence, energy stamps treat the problems of windfall profits and injury to households by creating a (potentially) pure transfer from suppliers to households with minimum government involvement. Disconnecting the issuance of stamps to a household from its energy use may present a political issue about individual "equity," but it is just

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*Such a program is called an entitlement program and has been applied with mixed success to the oil industry over the last few years. (See Phelps and Smith, 1977.) Note that the requirement for utility specific stamps (or pipeline specific stamps at the utility-pipeline interface) does not require that individual utilities issue the stamps. Stamps could be issued by municipal authorities, a federal agency, the utility, or anyone else. Since the stamps simply induce a transfer from utilities to consumers, the choice of who issues the stamps should depend on who can do it at least cost.

this feature that makes the stamps attractive from an economic point of view.

Yet a third approach is to allow marginal cost pricing on all units of gas and to confiscate lump sums from the utility and pipelines in some kind of windfall profits tax or franchise fee. For example, consider a utility and its supplying pipelines serving 500,000 households. In a previous example (pp. 25-27), the pipelines and utility shed excess profits by charging a lower price for inframarginal purchases of gas than for marginal purchases, saving each household about $120. Suppose $80 of this came from "inframarginal" gas contracts averaged by the pipelines and $40 from contracts averaged into these initial contracts by the utility. Then this same sum of profits could be shed through a $40 million tax on the relevant pipelines and a $20 million tax on the utility. These contributions could then be redistributed as relief from property and sales taxes at the local level and income taxes at the federal level. So long as redistribution is not directly tied to the use of gas, this windfall profits tax would eliminate the subsidy to gas.

On a purely conceptual level, this approach is equivalent to the use of energy stamps. Both extract an equivalent lump sum from utilities and pipelines and redistribute it to consumers. The two will have different administrative problems and perhaps different redistributive incidence. To use a stamp system, we must administratively determine (a) to whom stamps will be awarded; (b) the purchase price guaranteed by the stamps; and (c) the number of stamps issued.

The first point determines the relative incidence of a stamp program on various households. Tying the right to stamps to income will have a different effect from tying it to property owned. Making the right to stamps progressive with income or property will have a different effect from making it proportional or regressive. We can expect politicians to manipulate the distributive incidence of these stamps. Point (a) also determines the deadweight or social loss associated with the way the stamps are redistributed. Potentially, stamps could be distributed in a way that did not distort any margins, but in practice, it is not likely to occur. Tying stamps to income will

affect incentives to work; tying them to property or sales will affect the demand for property or goods subject to a sales tax. In general, we can expect the deadweight loss associated with these distortions to be relatively small compared with the distortion caused by average cost pricing.* But their size may be important in deciding how to assign stamps.

Precisely the same *types* of choices arise in selecting a financial instrument through which to redistribute a windfall profits tax or franchise fee. Choices among local sales, property, or income taxes, and the way in which the windfall tax will reduce any of them, raises the same type of questions as those about who gets stamps. Points (b) and (c) taken together raise the same administrative questions as the determination of the lump sum to be confiscated from profits. Conceptually, then, energy stamps and a lump-sum windfall tax are equivalent. Our choice between them will depend on which is administratively simpler and which has greater political appeal.

In sum, a number of instruments can be used to return the additional funds that consumers would have to pay under replacement cost pricing. Those that eliminate the subsidy to gas or energy most fully are also the ones that are the most uncoupled from individual payments and the least likely to satisfy the desires of individuals for compensation. To the extent that individual compensation is required politically, some subsidies to gas or energy might have to be retained under replacement cost pricing.

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*This is a variation of the problem of direct and indirect taxes (Little, 1951). Neither is preferable to the other on purely theoretical grounds. But the weight of the evidence generally supports indirect taxes. (See Harberger, 1964.)

IV. OPTION 2: TAXATION OF GAS AND SUBSIDIZATION OF GAS SUBSTITUTES

Replacement cost pricing gives us the correct level of consumption by permitting the correct price in the market. But the undesirable distributive effects of such pricing, or the cost and complexity of correcting these effects, may eliminate it as a viable option. An alternative is to retain average cost pricing as it is used today and either tax gas or subsidize substitutes for gas to more nearly approach the optimal social level of consumption defined in Section III. This section examines such taxes and subsidies, illustrating them with numerical examples.

An excise tax on gas, equal to the difference between the consumer's replacement cost and the real replacement cost of gas, can give us the same level of gas consumption as that under replacement cost pricing. Conceptually, such a tax is no different from the franchise fee discussed in Section III. The two create the same constant marginal price of gas for all levels of consumption. Their sizes must be administratively determined. And they can be rebated to consumers through tax relief in the same way.

Consider the options of replacement cost pricing and average cost pricing with an excise tax when a substitute for gas, say solar, is available. Figure 4 illustrates this case. D_{sh}, MC_g, and AC_g are the same as in Fig. 2. MC_s represents the penetration of solar at various marginal prices for gas.* This curve, like the others, is purely hypothetical. For our purposes, it is not important whether it is short

*MC_s is the price of gas at which some increment of solar becomes viable. If this means that it offers equivalent space heating services at a lower cost to the consumer, the price of solar implied by this curve will depend on the relative efficiencies of gas and solar, the inherent rate assumed by the consumer, the reliability of solar, and so on. Of course, as with all bimodal choices, it will also depend on consumer ignorance, seemingly irrational resistance to change, and other bothersome influences. We will not discuss them here; for simplicity, we will simply assume that MC_s reflects a legitimate cost of solar expressed in gas-equivalent terms. We will also assume that,

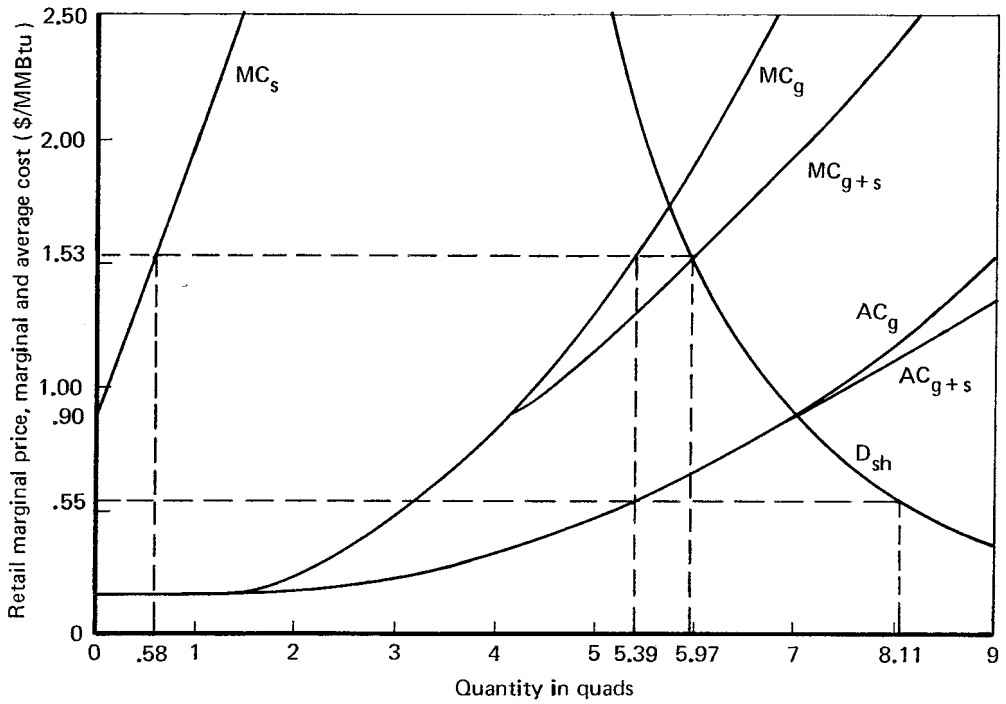

Fig. 4 — Simplified market for space heating, with solar and gas options

or long term. It states, for example, that at a $2.00 marginal price of gas, 1 quad of gas would be displaced by solar in the heating of homes (an optimistic forecast for solar).

The introduction of a new energy source opens the possibility of more consumption of energy at a given cost. The marginal cost of space heating, for example, shifts down from MC_g to MC_{g+s}. MC_{g+s} is the horizontal sum of MC_g and MC_s. The solar option, then, reduces the marginal price of heating services (in terms of gas) from $1.74/MMBtu to $1.53/MMBtu. It reduces the use of gas from 5.74 quads to 5.39, replacing it with solar to allow consumption of space heating at the level that 5.97 quads of gas would provide. For the reasons discussed in Section III, that is the preferred pattern of consumption.

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whereas solar will replace gas, utilities and pipelines will be allowed to recover profits proportional to their existing capacity, used or unused. That is, introduction of solar will not affect the fixed costs of transmitting and distributing gas.

Compare this pattern with the average cost pricing solution. This occurs where the horizontal sum of AC_g and MC_s, AC_{g+s}, clears the market with the demand curve. In this example, consumption is unaltered by the introduction of solar. Average cost pricing not only encourages overconsumption, then; it also discourages the use of solar to reduce the cost of this consumption. It is relatively easy to show that correcting the first distortion increases national income by $.57 billion and the second, by $.82 billion. The sum of these two amounts is the difference between the gains to utilities and pipelines, $5.26 billion, and solar producers, $.18 billion, on the one hand, and the loss to consumers, $4.05 billion, on the other; they are the gains and losses associated with a shift to replacement cost pricing.*

Compensatory schemes, of course, can take advantage of the increases in national income associated with the shift to replacement cost pricing of gas. An excise tax can be used as one such scheme under average cost pricing. To extract the full "excess" profit from pipelines and utilities, we simply set it equal to the difference between marginal cost, $1.53, and the average cost price charged, $.55. Consumers then use the marginal cost as their replacement cost and make the right choices (a) about the relative use of gas and solar, and (b) about the total consumption of space heating.† Under this scheme, the full increase in profits, $5.26 billion, goes to taxpayers instead of to gas suppliers. But appropriate redistribution through

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*The social gain associated with the use of solar instead of gas is the area bounded by MC_g, MC_{g+s} and 7 quads. The social gain from eliminating overconsumption is the area bounded by MC_{g+s}, D_{sh}, and 7 quads. By definition, they equal the difference in the transfers to and from various actors. The transfer to pipelines and utilities is the area bounded by the marginal price, $1.53, and the average cost of gas, $.55, and the ordinate and quantity of gas consumed, 5.39 quads. That to solar producers is the triangle bounded by MC_s, the price, $1.53, and the ordinate. And the loss to consumers is the area bounded by D_{sh}, the ordinate, and the marginal prices $1.53 and $.90.

†Note that the normal objection to energy taxes--namely, that they encourage suboptimal production--does not apply here. A regulatory pricing policy inflates demand above its real level; a tax is meant not just to encourage conservation but to make demand more nearly reflect its real level. The tax corrects a distortion; it does not introduce one in the name of conservation.

fiscal instruments, especially tax relief, can provide an incidence identical to that of any of the compensatory arrangements discussed in Section III.

This does not mean that an excise tax is identical to replacement cost pricing. In spite of the fact that it can provide the same incidence, an excise tax is likely to be less attractive politically than a franchise fee under replacement cost pricing. On the other hand, an excise tax is likely to be administratively simpler. Because (properly administered) average cost pricing transfers all inframarginal pipeline profits to the utilities, the tax need only be applied at the utility level. Of course, redistribution of the excise tax revenue that shares part of the national income gain with pipelines will still require some administrative calculations at the pipeline level. In sum, the choice between replacement cost pricing with compensation and average cost pricing with an excise tax depends more on administrative and political factors than economic ones.

If a tax on gas is infeasible, an alternative is a subsidy for gas substitutes--in our example, solar. As a subsidy on solar increases, the gas equivalent cost of solar to the consumer, represented by MC_s in Fig. 4, will fall. The horizontal sum of this new curve and AC_g, the supply curve for gas, will clear the market at ever lower marginal prices for heating services and with an ever-increasing share provided by solar.

Perhaps the most direct way to pursue the proper use of gas with a subsidy to solar is to increase the solar subsidy until consumption of gas equals that under replacement cost pricing. This will occur, of course, when the price paid for solar equals that paid for gas consumed at the replacement cost pricing level, \$.55/MMBtu.* At this price, the heating market clears at 8.11 quads, calling for 2.72 gas equivalent quads of solar. Such a quantity is forthcoming only if solar is subsidized at \$3.34/MMBtu, an outlay by taxpayers of \$9.08 billion! And it reduces national income by \$2.39 billion.†

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*This is the average cost of producing the replacement cost pricing level of gas consumption, 5.3 quads.

†If the supply curve for solar remains linear, the marginal cost of supplying 2.72 quads is \$3.89/MMBtu, whence the subsidy in the

Subsidies, then, do not necessarily improve on the prevailing arrangement. If any subsidy is to be applied, it should be an "optimal" subsidy. This is the subsidy that minimizes the cost of producing any particular level of heating with alternative technologies not all priced at marginal cost. Minimization is accomplished by setting subsidies to ensure that the perceived marginal costs of all alternatives are equal.* Under average cost pricing, this equalization is possible only if solar is explicitly subsidized by the same amount that gas is implicitly subsidized. Then, when subsidized prices of the two are equal, their marginal costs will also be equal. The fact that gas's implicit subsidy varies with its level of use makes this procedure tricky. Conceptually, however, it is straightforward. Figure 5 explains it in terms of our hypothetical gas market.

Consider two examples. All curves but AC' should be familiar by now; we will discuss AC' in a moment. In the first example, suppose we wish to produce the level of space heating set by marginal price cost pricing, 5.97 quads. The minimum marginal cost of producing this level with gas and solar is $1.53/MMBtu. The average cost of gas associated with this amount is, as we have seen, $.55/MMBtu, implying a subsidy to gas of $.98/MMBtu. If solar is subsidized at this level, 5.97 quads of space heating will be brought forth at $.55/MMBtu. This is represented by the point a_1 in Fig. 5. The allocative result is identical with the marginal cost pricing solution, but excess demand exists at this low price.

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text. Solar suppliers, of course, do not retain the full subsidy, but only the producer surplus generated by it, the triangle bounded by the ordinate, MC_s, and the price, $3.89/MMBtu. This is $4.07 billion. The reduction in the price of heating increases consumption and consumer welfare by $2.62 billion. Gas suppliers remain unaffected, and when we compare these benefits with the taxpayer outlay, we come up $2.39 billion short, the amount by which such a subsidy reduces national income.

*The reason for doing this is simple. Suppose a given quantity of space heating is produced with quantities of gas and solar at which the marginal cost of gas exceeds that of solar. That is what occurs with average cost pricing and no solar subsidy. Then, substituting a unit of solar for a unit of gas will reduce the total cost of providing this level of space heat. A similar cost-saving substitution will always be possible *unless* the marginal costs of the options are equal.

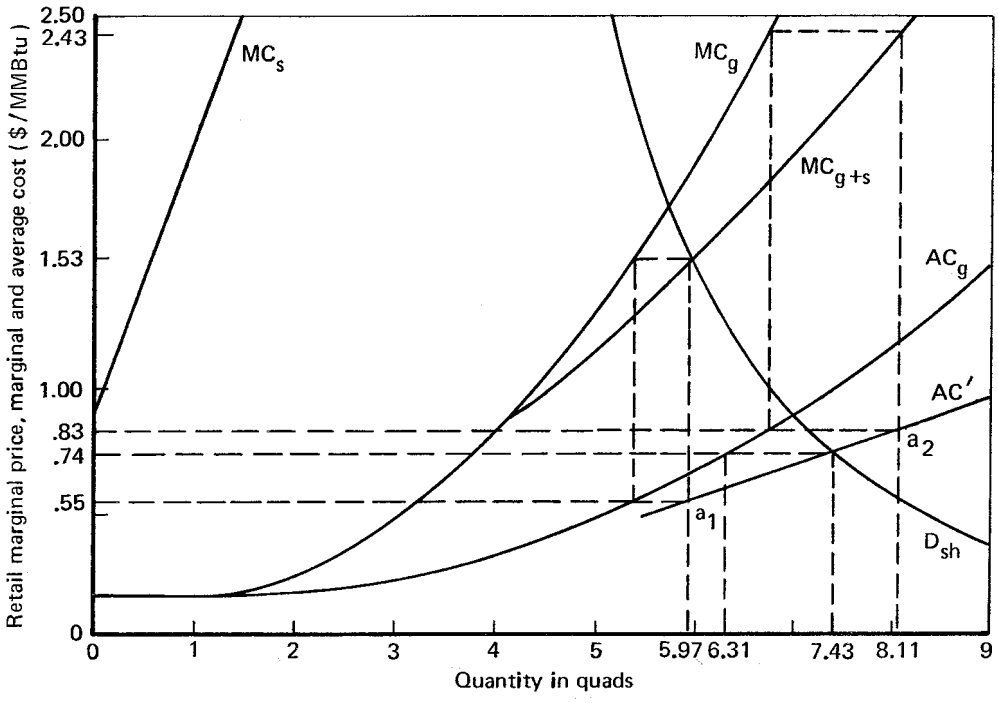

Fig. 5 — Calculation of the optimal subsidy for solar in a simplified space-heating market

Consider now the optimal way to supply 8.11 quads, the level supplied by our earlier subsidy for solar. The minimum marginal cost of producing 8.11 quads is $2.43/MMBtu, and the average cost of producing gas at the level that yields this marginal cost is $.83/MMBtu; gas is subsidized here at $1.60/MMBtu. Providing this subsidy to solar will bring forth at minimum cost 8.11 quads of space heating at $.83/MMBtu, at a_2. Excess supply exists at this point.

Repeating the process for alternative levels of consumption ultimately traces out a locus, AC', which intersects D_{sh} at 7.43 quads and $.74/MMBtu. The optimal subsidy to solar at this market-clearing solution is $1.39/MMBtu. Output is composed of 6.31 quads of gas and 1.12 quads of solar. It increases national income by $.28 billion relative

to what could be had under average cost pricing.* That is, in this example, an optimal subsidy is somewhat more desirable than the status quo. In other instances, it could be less desirable than average cost pricing. The optimal subsidy encourages the use of solar where it is cost justified and thereby reduces the cost of producing any given level of space heating. But it also encourages consumption beyond the level associated with average cost pricing, increasing the waste of valuable energy resources in activities of relatively low value. In comparing average cost pricing and the optimal subsidy, we must consider which effect is more important; in this particular example, encouragement to use cost-saving solar dominates.

Even if an optimal subsidy for solar is considered desirable, it is not so easy to choose its level if we wish to consider nonsolar options at the same time. New active and passive alternatives, as well as traditional sources, should be subsidized as well. Each will require a separate subsidy--subsidies must be designed to keep the marginal *social* costs of each alternative equal to one another--with its attendant problems of estimation and administration. In the end, the distortion that makes all of these subsidies necessary can be removed with a tax or an alternative pricing arrangement. Since the direct removal of this distortion will lead to greater social welfare than these myriad subsidies could ever achieve, the more direct approach to our problem makes more economic sense. In our illustration, for example, an optimal subsidy for solar of $1.39/MMBtu will cost the community over $1.1 billion in irretrievable resources.

Table 2 brings together the allocative and distributive effects that the various tax and subsidy schemes examined in this section have on our hypothetical gas market. To put these numbers in proper perspective, note that consumers pay $14 billion annually under current average cost pricing. Marginal cost pricing or, failing that, an excise tax on gas sold under average cost pricing generates the biggest

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*The optimal subsidy increases consumer welfare by about $1.15 billion and the profits of solar suppliers by $.69 billion. Gas suppliers remain unaffected. These benefits are financed by taxpayer-financed subsidies totaling $1.56 billion.

Table 2

SUMMARY OF EFFECTS OF POLICY CHANGES

	Average Cost Pricing				
	No Changes	Add Excise Tax	Add Subsidy To Induce MC Pricing Level of Gas	Add Optimal Subsidy	Marginal Cost Pricing
Quantity (quads)					
Gas	7.00	5.39	5.39	6.31	5.39
Solar	0	.58	2.72	1.12	.58
Total	7.00	5.97	8.11	7.43	5.97
Marginal Cost ($/MMBtu)					
Gas	2.65	1.53	1.53	2.13	1.53
Solar	--	1.53	3.89	2.13	1.53
Marginal Price ($/MMBtu)	.90	1.53	.55	.74	1.53
Δ Quantity (quads)[a]					
Gas	0	-1.61	-1.61	-.69	-1.61
Solar	0	.58	2.72	1.12	.58
Total	0	-1.03	1.11	.43	-1.03
Δ Marginal Cost ($/MMBtu)[a]					
Gas	0	-1.12	-1.27	-.52	-1.12
Solar	0	--	--	--	--
Δ Marginal Price ($/MMBtu)[a]	0	.63	-.35	-.16	.63
Δ Benefits ($ billions)[a]					
Gas suppliers	0	0	0	0	5.26
Solar suppliers	0	.18	4.07	.69	.18
Consumers	0	-4.05	2.62	1.15	-4.05
Taxpayers	0	5.26	-9.08	-1.56	0
Net total	0	1.39	-2.39	.28	1.39

[a]Relative to average cost pricing with no changes.

surplus: $1.39 billion. Both of these reduce consumer income $4.05 billion, but the existence of a surplus means that the kinds of compensatory instruments discussed in Section III can be used to recover this $4 billion and more for consumers.

If these policies cannot be used for political or administrative reasons, subsidization of options to gas may or may not be desirable. It encourages the entry of solar and other options that replace high-cost gas; but it also encourages the wasteful consumption of space

heating and other commodities provided by gas. It is useful to note that such a subsidy benefits consumers and solar producers, both of whom are more likely than the general taxpayer to be cognizant of the distributive effects of the subsidy. The pressure these groups can bring to bear may convince politicians, then, that such subsidies are more desirable than they really are to the country as a whole. Note that such effects can occur with the "optimal" subsidy or the clearly undesirable subsidy to solar that aims to bring the consumption of gas to the marginal cost pricing level. If a subsidy must be pursued, the nearer it is to the optimal, the better. But the status quo may be preferable even to the optimal subsidy.

V. OPTION 3: UTILITY OWNERSHIP OF TECHNOLOGY

Having discussed some of the better-known economic solutions to a divergence between consumer price and real replacement cost, we can now turn to a policy option that has recently raised considerable interest: utility ownership of new technology. Our review of the traditional economic arguments will provide some tools with which to examine this proposal. This section sets out the argument in favor of utility ownership of new technology and then reviews it in detail.*

Even if a utility is required to use average cost pricing, it can still perceive its marginal cost of providing gas. Given its price structure, for example, a utility typically attempts to minimize the cost of providing the energy demanded under this structure.† A utility must price any new technology competitively with its gas, regardless of cost. Otherwise, the utility could not induce consumers to substitute away from gas. In essence, then, energy from new technology is delivered under the same rate structure as gas. But a utility will not sell energy from a technology at rates insufficient to cover the cost of that technology unless it can spread the cost of the technology across all users and recover its investment. Regulators must treat new technologies and new gas the same way.‡ As long as regulators do this, then, a utility will be willing to compare the

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*Petersen and Owen (1977) provide an alternative treatment of utility ownership by constructing analogies between regulations associated with such ownership and historical regulations in other industries.

†The reason is that profit regulation is ex ante, not ex post. A rate structure is set to yield an expected allowed profit. Once the rate structure is set, however, the utility reaps whatever profits it can get until the next regulatory review. Excessive profits lead to an adjustment of rates--and hence profit control--over the long run. But cost minimization can still be attractive within the constraints implicit in longer-term regulatory control.

‡Regulators will obviously find a "commingling" doctrine difficult to use as a rationale for such pricing; another will have to be developed.

marginal cost of new technologies with that of new gas and subsidize them both in the same way.*

This raises several issues. To what extent does such a scheme allow a utility to recognize the real replacement costs of gas? What kinds of technologies will a utility choose to introduce under such a scheme? How will it price them? How would such a scheme affect the general market for new technologies and in particular their introduction by private, nonutility firms? How do a utility's real costs of introducing new technologies compare with the real costs of other companies? The remainder of this section addresses these issues.

Relative to the first issue, not all averaging of gas prices occurs at the utility level; in fact, most of it occurs at the pipeline level. Hence, unless the highest-cost gas a utility buys comes from outside the pipeline network, utility ownership of new technologies will not allow the utility to recognize the real replacement cost of gas. In fact, it will judge the replacement cost of gas to be much lower than it really is. The only gas likely to circumvent the pipelines over the long run is locally produced synthetic gas, at present and for the foreseeable future a very costly source.† But even if the utility could recognize the real replacement cost of gas, utility ownership of new technology raises enough other problems to draw

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*Of the various arguments in favor of utility "participation" in the introduction of new technologies, the "Rosenberg Plan," named for William G. Rosenberg, a former assistant administrator at the FEA, is probably the best known. It has changed over time, but its basic intention is for utilities to install insulation in homes and recover the cost through gas bills. For details, see *Energy Research Reports* (February 21, 1977). Hirshberg and Davis (1977, pp. 4.2-4.8) propose a similar plan for solar systems specifically as a solution to the barrier to entry presented by average cost pricing of gas. (Cf. Ricci, 1977.)

†As argued in Section II, the most likely marginal source of gas is domestic gas if the price of new gas is deregulated and foreign gas if it is not. Synthetic gas is more costly than either of them, and so it will probably serve only as a peaking source in the near future, without government subsidies. The utility might recognize the real cost of these pipeline sources if they were "incrementally priced." (See Hederman, 1978.)

its usefulness into question. For the sake of argument, the remainder of this section assumes that the utility recognizes the real replacement cost of gas.

The second issue is the way in which a utility chooses what new technologies to introduce and how to price them. It will presumably choose technologies that increase its profits. In the short run, any technology less costly than gas will look attractive. These technologies reduce the cost of producing any given level of space heating, leading to excess profits. The utility can retain them until its profits are reviewed. If this were the only effect, the utility would tend to choose the correct technologies.

Over the longer run, however, it must shed the profits. By lowering rates, it can expand demand for space heating and perhaps for capacity, allowing it to increase its rate base and retain some of the cost savings. Note that new technologies embody their own capital or contribution to the rate base and may automatically allow the utility to capture some of the cost savings. The utility will, in fact, seek out such technologies and encourage development of new capital-intensive technologies.* Highly capital-intensive technologies such as solar and insulation will tend to be overemphasized and oversized.† That is, the utility will tend to choose an inefficient pattern of space heating production.

In the end, the utility will choose a pattern of technologies so that an incremental dollar spent on any one of them will have the same effect on profits as an incremental expenditure on any other. To the extent that lower-cost technologies allow this over the long run, rates will fall to shed profits from time to time, and we will be faced with an arrangement quite analogous to the optimal subsidy presented in Section IV. The cross subsidy from inframarginal gas encourages the entry of low-cost technologies but also encourages overconsumption of

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*Section II discusses this point. Recall that there is considerable controversy over how important this consideration is to utilities. See the third footnote on p. 7 for references.

†For an algebraic proof of this tendency to overcapitalize in the tradition of Averch and Johnson (1962) and Baumol and Klevorick (1970), see Petersen and Owen (1977).

space heating. Whether the result is desirable depends on which of these effects dominates the other.

On the other hand, the pursuit of capital-intensive technologies may actually raise rates (a) to pay for the costly new technologies and (b) to cover the additional allowed profits attached to this new capacity. These new technologies would have to be more capital-intensive than gas, but that is not particularly restrictive.* This concern with capital intensity suggests that the pattern of heating production chosen by utilities will be inefficient: the same amount of heating could be provided at lower cost. Even with such inefficiency, the utilities can use inframarginal cuts on old gas to subsidize their new acquisitions and provide them at a cost to the consumer lower than any price that a private, unregulated company could afford to charge.

This point raises the third issue: what effect would utility ownership have on competition in the markets for new technologies? As long as the utility can treat solar or other new technologies in the same way that it treats gas, ownership has three major effects. First it closes nonutility producers out of the market for any technology it chooses to introduce. Since nonutility producers must charge a price sufficient to cover the technology's cost of production, the utility can use its low-cost gas contracts to cross-subsidize the technology and underprice competitors. Second, it brings competitive markets under regulation. Under normal pricing, markets for technologies such as heat pumps, solar collectors, storage facilities, insulation, and the like show every indication of being competitive and providing the optimal level of these technologies to the market. Their producers and marketers are also more likely to pursue efficient service and innovation if they must compete than if they cannot. Third, as the production cost of gas rises,

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*New technologies appear to be particularly capital-intensive from an accounting point of view. The installation of solar or insulation requires skilled labor, but the value added of this labor can presumably be included in the capital value of the installed technology, artificially increasing the capital intensity of these technologies. Considerable capital value, on the other hand, resides in the price of gas to utilities; but utility regulators will not allow this form of capital to be included in a utility's rate base. Such regulatory accounting artificially underestimates the capital intensity of gas.

alternatives to gas become more and more attractive; these alternatives would cut into the demand for utility services in the absence of regulation. Utility ownership allows a utility to avoid this prospect and maintain control of its traditional market. Under this scheme, the prospect of unfair competition and the regulation of potentially competitive activities will end only when the utility's low-cost gas contracts run out and average cost equals marginal cost by default. This problem is unlikely to occur in the near future.

In sum, any technology that is to be put on an equal footing with gas--or any other utility-controlled technology--must be placed in the utility's rate base. The gas utility's place in the provision of space heating and other heating services is assured. It might be argued that the utility will find some technologies too difficult to manage. They could then still be provided by private companies. This situation is particularly likely to characterize passive technologies. For example, it is difficult enough to define a utility's property rights and responsibility with respect to attic insulation. How does one define its rights to adobe walls, energy-conserving architectural designs, or strategically placed vines and trees? Surely these technologies would not be dominated by the utility. Unfortunately, the utility would dominate substitutes for them. It could subsidize these substitutes in a way that discriminated against passive technologies and any others the utility chose not to pursue. Utility ownership, then, gives the utility control over not only the part of the market it wishes to participate in directly but the rest of the market as well.

It should be noted that the utility's advantage derives primarily from treating the costs of new technologies in the same way as new gas costs are treated. The utility could introduce new technologies on more even odds through an unregulated subsidiary. But such a subsidiary would defeat the primary purpose of utility involvement; the utility could no longer use its low-cost gas to subsidize new technologies in the same way that it subsidized high-cost gas. If the subsidiary and mother company did not deal at arm's length, the utility might be able to provide its subsidiary with unfair advantage. But since a subsidiary

is not likely to solve the problem facing us, we will not deal with this problem.*

We now come to the final issue. If the utility and other companies could compete on even ground, who would dominate the market for these new technologies? It is often suggested that the utility, through its billings, has ready access to most potential customers for new technology. Not only could it reach them more easily with advertising, it could also bill them more easily. That, however, does not preclude other producers from recognizing these economies and contracting with the utility for advertising space in its mailings or even a billing service, if ready access is the utility's comparative advantage. The utility could collect the full difference in cost for these services, the full amount it could hope to gain by refusing to sell its services to competitors. On the other hand, credit card and major oil companies also have extensive mailings that could provide similar services. Only the mailing list is different.

Another advantage utilities are said to possess is a lower cost of capital. It is not clear what this advantage stems from or whether it could be transferred to activities different from those it has traditionally pursued. A natural question to ask is, if its capital costs are genuinely lower, why hasn't the typical utility exploited this advantage and used it to finance consumers through a financial intermediary? Much of the advantage relates to the low risk of utility investments, made possible by regulation and the special tax advantages that are available because of regulation. If these advantages are important, we once again have regulation-induced benefits favoring the utility in a potentially competitive market. Part of the advantage may

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*The utility could use political power or economic means to favor its subsidiary. The first is hard to pin down. The second is somewhat more subject to analysis. To the extent that the utility can include some of the subsidiary's costs or assets in its own accounting "above the line," it may be able to increase its allowable profits. Some of these profits might be used to favor the subsidiary in order to allow it to increase its market share and provide it with further opportunity to doctor the books. Again, since these issues are not crucial to the problem at hand, we will not belabor them.

also be related to the utility's ability to withdraw service quickly from delinquent users. Withdrawal of service might prove somewhat more difficult if the service in question were insulation or a solar system or some other installed appliance. Of course, the company could still withdraw all service, which would give it an economic advantage over a company that would have to repossess installed appliances on which payments were delinquent.

A utility, then, may have lower costs of identifying and billing customers and also have a lower cost of capital. These lower costs suggest that, other things being equal, the utility would be competitive in an unrestricted market. Note that these lower costs hold whether or not alternative technologies are regulated in the same way as new gas. Allowing the utility to introduce new technology through an unregulated subsidiary could allow us to take advantage of these economies, if they exist, without the difficulties associated with regulation. That is, if we can assume that a utility will compete fairly, we should not restrict its participation in the introduction of new technologies.

In sum, utility ownership of new technology is difficult to defend as a remedy for the average cost pricing of gas. Most fundamentally, it treats only the cost averaging done at the utility level, leaving the utility to underestimate both the cost of new gas and the savings available from new substitutes for gas. In the absence of an Averch-Johnson-Wellisz propensity to overcapitalize, utility ownership leads the utility to underprice not only gas but also any new technologies it introduces. The utility will sell gas for even less than its current price! Averch-Johnson-Wellisz effects will mitigate this underpricing but also lead to discrimination in favor of capital-intensive technologies and provision of heating services at excessive cost (to the country, not the consumer). Allowing utilities to subsidize new technologies with inframarginal rents from old gas contracts closes all other companies out of the market for these technologies and introduces regulation and monopolistic elements into markets that would otherwise be competitive. Even technologies that utilities prefer not to handle will be handicapped by being forced to compete with the technologies that utilities do introduce. Utilities do exhibit some potential economies in billing, advertising, and financing capital expansion that

other companies do not. But the regulation that induces the difficulties discussed above is not required to realize these economies. These difficulties should not be cited to rule out utility introduction of new techologies through an unregulated subsidiary.

VI. CONCLUSIONS

Average cost pricing of gas is a serious problem in the residential and commercial markets for energy. This report examines three policy options that can be broken down into six specific proposals:

Price at marginal cost and compensate consumers with

1. increasing block or lifeline rates;
2. energy stamps; or
3. a windfall profit tax or franchise tax.

Continue to price at average cost and ameliorate its distortions with

4. an excise tax on gas;
5. subsidies on gas substitutes; or
6. utility ownership of new technologies that could substitute for gas.

What can we say about which is the best option? As emphasized in the Introduction, this report is not meant to provide a final answer to this question. But we should now be in a position to determine what additional information is required to answer the question and perhaps to shorten the list somewhat.

This report uses economic tools to provide two types of information: (a) changes in national income (neglecting administration costs) associated with each alternative; and (b) how those changes are distributed among various political interests in the economy. The first serves as an upper bound on income increases and a lower bound on income losses; if the policy does not look good in terms of this number, it can only look worse once administrative costs are considered. The second determines the extent to which redistribution would be required to achieve some politically desirable distribution of benefits from a policy. Redistribution involves additional administrative costs, which may be high enough to make a policy that increases national income look unattractive. Obviously, administrative costs play a large role in all of these factors; thus we cannot be very definitive without an understanding of these costs.

We can, however, make one point. Any policy that reduces national income from that offered under current average cost pricing is suspect. It will be politically attractive only if it transfers sufficient benefits to some interest groups to warrant the (larger) losses imposed on others. Redistribution is not so important here because the losers cannot be fully compensated anyway. Presumably, those who benefit are sufficiently powerful or deserving to receive benefits generated at the cost of greater injury elsewhere. As an example, consider the subsidy to solar, which aims to provide gas at the marginal cost pricing level under average cost pricing. It costs the nation over $2 billion and the taxpayers over $9 billion (column 3 of Table 2). Are solar producers and energy consumers sufficiently worthy to warrant taking $1.36 from taxpayers for every $1.00 delivered to them? It is unlikely. Are they sufficiently powerful to do this? This is more probable, but still unlikely. This alternative appears very unlikely.

It is more difficult to make definitive statements about the other options, and the difficulty is increased by two additional considerations. First, the concept of distribution in this report is class-oriented and not individual-oriented. Class compensation does not guarantee individual compensation. For example, if compensation to consumers under a replacement cost pricing scheme is shared equally by all consumers, larger users of gas receive less compensation for their loss than small users or nonusers. This is not necessarily bad. It simply puts additional pressure on large users to conserve gas. In this sense, it might be seen as a politically attractive way to reward those who conserve gas and punish those who do not without distorting any margins.* Nonetheless, a lifeline or increasing block rate may be appealing as evidence of an effort to provide individual compensation.

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*Buchanan (1959) sees incomplete compensation for losses caused by policy changes as a confiscation of property rights. This is correct and has important legal implications. Note, however, that a private market routinely rearranges property rights through pecuniary externalities. That is, the problem arises only because of existing government involvement. It might be argued that any compensation protects property rights better than a cost rise in an uncontrolled gas market, and that consumers should feel lucky to get any compensation at all.

This consideration may override the fact that these rates continue to subsidize gas and lead to its overconsumption. In the end, individual compensation must leave some residual subsidy.

Second, the costs and benefits in this report are hypothetical; even if measured with the best econometric techniques, they would never be more than estimates. It is equally true of administrative costs. Politicians and the public, then, may be reluctant to rely on such estimates and may require any policy to display a basic sense of fairness or reasonableness that a set of estimates may not be able to project. For example, a "commingling" doctrine may appear just and fair in a comparison with a replacement cost pricing scheme tied to some complex compensation scheme. Even if a policy increases national income and it appears possible to distribute this increase in a desirable way, it may still have to display some inherent political worth before it will succeed. In part, this problem is one of generating the proper rhetoric to accompany a new policy. But knowing how much of it is required will be useful to the policymaker.

Taken together, these three considerations--effects on national income net of administrative costs, type of compensation, and inherent political appeal--point to one other option that appears unlikely to succeed: the utility ownership option. Exact distributive effects for the utility ownership option are not worked out. But at best, this option can provide an optimal subsidy to new technologies; such a proposal, as we have seen, can increase or decrease national income. It is unlikely to do so properly, however, because it does not recognize the real replacement cost of gas. It also imposes unnecessary administrative costs and potentially distorting monopoly control on what we would expect to be competitive markets. And to the extent that utilities overcapitalize, it inflates the cost of providing new technologies and provides the wrong ones. All of these features can only make its performance less attractive than that of the optimal subsidy. Distributive effects are difficult to work out but they are unlikely to benefit consumers in the same way that the optimal subsidy does and will certainly benefit producers of alternative technologies less. And further utility domination of residential or commercial energy

markets is unlikely to have inherent political appeal. In sum, the utility ownership option does not look particularly viable.

The others all need further examination. Of these, the optimal subsidy appears to be the least desirable. It can reduce national income and it displays significant if as yet unmeasured administrative costs. But it does benefit solar producers and consumers without hurting gas producers; taxpayers foot the bill. And the benefits may well come in the form of one dollar or more for every dollar of tax money spent. That, together with the current political sensitivity about new energy technologies, may make it usable.

It should be emphasized, however, that any of the remaining schemes permits an even greater increase in national income. The only problem with them is the feasibility of redistributing this income in a politically satisfying way. Political appeal is probably the single most important area for future inquiry. Recall that all but one--the increasing block tariff scheme--are fiscally equivalent, and that even the block tariff is similar to the others. Not only to understand how they perform as a group, then, but simply to choose among them, we need to understand their administrative costs and inherent political appeal. This raises three issues.

First, two forms of administrative costs are involved, those associated with the collection of the surplus from producers and those associated with its redistribution. The increasing block tariff is attractive from this standpoint because it combines the two tasks into one operation, presumably conserving administrative costs. The excise tax on gas, on the other hand, conserves such costs by collecting the surplus at only one level--the utility level. All others must collect surplus from pipelines and utilities. Because its redistribution costs are likely to be similar to those of energy stamps or franchise fees, it is likely to be administratively cheaper than these options.

Second, two schemes--franchise fees and excise taxes--require direct use of fiscal revenues. The others require no direct government involvement. This may make franchise fees and excise taxes harder to sell in political discussions. It may also raise doubts about whether satisfactory compensation will actually occur.

And third, each of these schemes is likely to have inherent political values of its own, although we cannot be sure what they are. For example, consumers may feel more familiar with a stamp scheme than with the others, but does familiarity breed love or contempt? Alternatively, consumers may see a basic fairness in a lifeline or increasing block tariff; but how does this change as, say, the size of the lifeline is altered? One way to enhance the political appeal of the options that redistribute the income increase through fiscal instruments is to identify the amount returned to consumers explicitly. (This may also lessen fears that nothing will be returned.) Unfortunately this solution imposes additional administrative costs that may not be justified.

In the end, we are left with a list of options. Of these options, those that increase national income significantly--replacement cost pricing and average cost pricing with a tax on gas--appear to be the most intriguing. But we cannot say more about them or about subsidies to gas substitutes without more information on their administrative costs and basic political appeal. These are the questions we need to address next, and this conclusion has suggested some ways of approaching them. Utility ownership of substitutes for gas does not appear to warrant further study. There is enough work to do without worrying about this option any further.

APPENDIX

The numerical representations of the natural gas market used in the text are based on some very simple equations. The reader may find them useful in studying the examples offered here in more depth or in generating his own examples. This appendix presents the equations used in this study.

GAS SUPPLY

Compatible marginal and average cost functions were required to meet the following criteria. Marginal cost (MC_g) has to equal \$2.65/MMBtu at 7 quads; average cost (AC_g), \$.90/MMBtu at 7 quads. These two cost functions approximate the current market for residential-commercial gas. Setting MC_g and AC_g equal to \$.20/MMBtu at 0 quad, and choosing quadratic forms, yields:

$$MC_g = .2 - .1Q + .0642858Q^2$$

or

$$Q = \frac{.1 + (.2571432\ MC_g - .04142864)^{1/2}}{.1285716};$$

$$AC_g = .2 - .05Q + .0214285 71Q^2$$

or

$$Q = \frac{.05 + (.085714\ AC_g - .0146428)^{1/2}}{.042857}.$$

SOLAR SUPPLY

Solar supply was chosen simply to ensure that it would be viable under marginal cost pricing and not under average cost pricing. The condition is fulfilled by a linear function that equals 1 quad at \$2.00/MMBtu and 0 quad at \$.90/MMBtu:

$$MC_S = .9 + 1.1Q$$

or

$$Q = \frac{MC_S - .9}{1.1} .$$

SPACE-HEATING DEMAND

Gas is used primarily for space heating in the residential-commercial market. A constant elasticity function was chosen to reflect a short-run elasticity of -.3, representative of recent econometric estimates of this elasticity, and a demand for 7 quads at the current (marginal) price of $.90/MMBtu:

$$P_D = 590.52227Q^{-3.3333}$$

or

$$Q = 6.782203P_D^{-.3} .$$

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