APTD-1459

AN ANALYSIS OF THE REGULATORY ASPECTS OF NATURAL GAS SUPPLY

U.S. ENVIRONMENTAL PROTECTION AGENCY

Office of Air and Water Programs

Office of Air Quality Planning and Standards

Research Triangle Park, North Carolina 27711

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by

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CHAPTER I - INTRODUCTION

The fundamental objective of this study is to assist the Environmental Protection Agency in finding ways to increase the nation's supply of pipeline quality gas and low sulfur fuel oil for stationary utilization, by reference to government regulation which attend these fuels.

This report is limited to the analysis of regulatory aspects attending the supply of gas. The fuel oil portion of the study will be submitted separately to EPA.

For gas, Foster Associates first developed a comprehensive picture of the current situation as it relates to the regulation of supply and distribution of gas in the United States. This included (a) identification of regulatory authorities and their function, (b) a definition of existing procedures available for bringing about changes in the supply and distribution of gas, and (c) suggestions as to how EPA may participate to bring about changes defined in (b) above. After setting out the current situation, Foster Associates identifies future changes foreseen in the regulation of gas. Possible strategies for bringing about future changes are suggested, and estimates have been made respecting cost effectiveness and time requirements for optimal strategies.

The contents of this report are current as of December 15, 1972.

CHAPTER II - CONCLUSIONS AND RECOMMENDATIONS

That the United States today faces a critical shortage of gas is undisputed. Seven interstate pipelines in the past year have been compelled to reduce deliveries to customers below firm contract levels, and 15 pipelines have predicted the necessity to curtail customers in the current winter season. Moreover, for most pipelines, there has been no supply available to permit new or expanded service for some time. Carried through to the retail level, gas distributors in many areas of the nation have been forced either to refuse or sharply restrict the attachment of new and increased loads. Industrial users of gas are being increasingly forced to seek out alternative fuels which are generally available, if at all, only at higher prices.

Another alarming indicator of supply is the steady decline in the nation's gas reserve inventory picture. For example, as contrasted with a 92% overall increase in production over the 1958-1971 period, total proved gas reserves in the Lower 48 States of the U.S. in 1971 were 2% below their 1958 level. More significantly, during the past four years when production rose more than 13%, total proved reserves dropped by some 40 trillion cubic feet (from 289.3 trillion cubic feet at the beginning of 1968 to 247.4 trillion at the end of 1971), or nearly 15%. This drop reflects the fact that reserve additions in the Lower 48 States averaged only about 50% of production over the 1968-1971 period. The worsening supply trends also reflect a steady decline in exploratory gas well drilling for more than a decade.

Still a further manifestation of the current gas shortage is the proliferation of projects announced in the past few years for the importation

of foreign LNG and development of synthetic gas supplies. In addition, many U.S. pipelines and distributors are contributing large sums to gas exploration efforts in frontier areas of Canada and Alaska as well as to feasibility studies of pipeline projects to bring such gas to U.S. markets. Increasing attention is also being given to coal gasification projects, with one such proposal already filed with the FPC and others under active consideration.[1/] All of these supplemental supply sources are projected to entail substantially higher unit costs of gas supply than domestic production. But the anomaly is that the bulk of the projects are an outgrowth of the decline in available domestic gas which, in turn, has been brought about to a considerable degree by inadequate prices for wellhead production.

Regulatory Strategies for Increasing Gas Supply

This study suggests several possible regulatory strategies for increasing the supply of gas. Most of these strategies pertain to legislative action or FPC action to stimulate domestic production which, despite the publicity given to LNG, SNG and other such "glamor" sources of gas, will continue to provide the bulk of the nation's supply through at least this decade.[2/] At the same time, current projections indicate that domestic production will fall increasingly short of meeting demand in the years ahead. Therefore, it is also necessary to formulate regulatory policies

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1/ These projects are in addition to coal gasification research, jointly funded by industry and the Federal Government, aimed at development of a commercial process for converting coal to high-Btu pipeline quality gas by 1980.

2/ According to FPC Staff projections (shown on page V-18), production in the Lower 48 States will account for 94% of the estimated total U.S. gas supply (excluding Alaska) in 1975, 82% in 1980 and 71% in 1985.

at the earliest possible date to encourage development of supplemental gas projects meeting national interest and economic feasibility criteria. Even though gas imports and synthetic gas production will not be available in any important degree to augment domestic sources until the latter part of this decade or the early 1980's, the criteria and policies laid down in the next year or so will be instrumental in influencing future development.

It should also be noted that none of the more likely means for increasing gas supply will result in any substantial expansion of supply overnight. With respect to domestic gas, the results of any significant modifications of regulatory policy would take some time to perceive because of the time lag between exploration for new reserves and the date production commences to flow to markets. This lag is variously estimated at between three to seven years depending upon the producing area and distance from established market outlets. Nor, as indicated, do supplemental sources of gas supply offer much hope of supply alleviation for the immediate future. An exception could be the reforming of gas from naphtha and other light hydrocarbon feedstocks since reforming plants can be built within a period of two years or less. However, the bulk of naphtha feedstocks for such plants would have to be imported, thus raising questions concerning inter-fuel relationships and the direction of the nation's overall import policies in the years ahead.

1. Sanctity of Contract Legislation

One means of encouraging increased domestic production would be passage of legislation to assure contract sanctity, i.e., certainty of

price and other contract terms. So-called "sanctity of contract" bills were the subject of hearings before both House and Senate Committees in the last session of Congress, but were never reported out of those committees. These bills are not aimed at decontrol of producer prices. Rather, their purpose would be to immunize new producer contracts -- after a one-time review and approval by the FPC -- from subsequent regulatory change. The FPC review would extend to the entire pricing structure (initial price plus provisions for fixed escalations), the length of the contract and other contract terms. In passing on the contracts, the Commission would be prohibited from using the cost of service, public utility rate base method and instead would look to supply and demand factors, price levels deemed required to elicit adequate supplies for the interstate market, and economic and cost trends.

A major benefit of the sanctity of contract legislation would be the avoidance of the price confusion and risk which characterized FPC producer regulation in the 1960's. In South Louisiana, for example, the FPC rolled back price levels three times between 1960 and 1968. Such action was hardly inducive to producers to commit new reserves to the interstate market as opposed to the intrastate market where contract terms were binding. Another principal benefit would be to free the FPC from the cost of service ratemaking method. Although there are some (e.g., the American Public Gas Association and certain other consumer groups) who maintain that the cost of service approach is the only means of protecting consumers against unjust and unreasonable rates, it is our view that experience in the area rate proceedings over the past decade has shown application of the

cost method to producers on an area basis to present nearly as many difficulties as its application on an individual company basis. Significantly, in two recent area rate decisions, the FPC recognized that cost calculations cannot be mathematically precise, but rather reflect arbitrary judgments as to allocation procedures and a wide margin of error as to both data and methods used. (FPC Opinion No. 595 issued May 6, 1971 in the Texas Gulf Coast Area Proceeding; FPC Opinion No. 598 issued July 16, 1971 in the Southern Louisiana Area Rate Proceeding.) Relieved from any precedents or pressures to attempt to apply the cost method further for new gas supplies, the FPC could proceed to develop more rational regulatory standards giving greater recognition to market forces and the incentives necessary to elicit greater supply additions.

Generally speaking, there is little opposition to the concept of contract sanctity. However, various provisions of the proposed bills have been criticized on the ground that they go far beyond what is necessary to accomplish that goal. These criticisms reflect a fear of departing very far from the past regulatory scheme. However, it is now generally acknowledged that this past scheme was a factor which contributed in significant degree to the development of the present gas shortage.

Assuming reintroduction of the sanctity of contract bills which died in the last Congress, it is recommended that EPA join with other Federal Government bodies -- including the Departments of Interior and Commerce, and the Office of Management and Budget -- which supported this legislation in the past. Passage of these bills, in essentially the same

form as previously proposed, would appear to be a minimum step toward ameliorating the domestic supply situation. While dedication of additional gas reserves to the interstate market would not be guaranteed, the price and other assurance provided by sanctity of contract legislation would remove some present disincentives to interstate sales by producers. The sanctity of contract step, however, is unlikely to prove effective unless coupled with FPC action to increase producer prices to more realistic market levels. (See pages V-25 and V-28 through V-32 for a further discussion of the sanctity of contract matter.)

2. Decontrol Legislation

Another regulatory strategy requiring Congressional action is decontrol of wellhead prices. This approach is urged by those who believe that sanctity of contract legislation would not go far enough in restoring the ability of gas prices in the field to react to market forces and hence in stimulating the needed turnaround in domestic supply.

As discussed further on pages V-32 through V-37, deregulation proposals take three general forms: decontrol of all gas, decontrol of gas under new contracts only, and decontrol of new gas contracts subject to certain safeguards.[1/] Decontrol of producer prices for new gas are

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1/ In the last category, bills were introduced in the last two sessions of Congress by Senator Tower and Rep. Price (both of Texas) to eliminate FPC rate control over future contracts, provided that (a) the acreage involved had not previously been dedicated to the interstate market, (b) contract prices, including any escalations, are expressed in terms of a definite charge per unit, with indefinite price escalations prohibited, and (c) all other contractual provisions (such as quality, rate of take, prepayment arrangements, and abandonment of service), regardless of their effect upon contract prices, continue to be subject to Commission approval and review.

known to be under active consideration by the Administration at this time. Support for legislation of this nature has been expressed by officials of the Interior, Commerce and State Departments; the Director of the Office of Emergency Preparedness; and the President's Council of Economic Advisers, among others. In addition, two current FPC members -- Pinkney Walker and Rush Moody -- favor immediate decontrol of domestic wellhead prices.

On the other hand, efforts to deregulate producers will probably be opposed by consumer and other interests as well. FPC Chairman Nassikas, for example, has come out against deregulation on the principal ground that the results would be chaotic in a time of supply shortage. He and others question whether producer markets are sufficiently competitive to permit adjustment to realistic price levels and whether, once gas price ceilings are removed, interfuel competition could provide any meaningful restraints on increasing gas prices. Another major question is the extent to which the price of gas would rise and the degree to which supply would respond if FPC wellhead regulation were eliminated.

Further, the reaction of Congress to any decontrol proposals is problematical at best.

Despite the uncertainties and reservations concerning the effects of decontrol, legislation in this direction would assuredly spur greater exploratory efforts and lead to increased gas supply additions. Should EPA desire to support the decontrol route, probably the type of proposal most likely of passage by Congress (and the one least disruptive to present consumer markets) would be legislation along the lines proposed by Senator

Tower. In other words, deregulation would be limited to new gas contracts only, with safeguards to preserve some measure of FPC control.

3. Legislation to Expand Federal Regulation

Another general approach advocated by some to meet the current gas shortage is the expansion, not the reduction, of federal regulation. This approach includes proposals to establish national end-use controls on consumption of gas, together with extension of FPC jurisdiction over intrastate and direct sales in order to prevent unregulated markets from siphoning off new gas supplies for low priority uses.

Pressures for federal end-use controls over all gas markets reflect growing concern respecting the potential consequences of gas supply curtailments. If the present gas situation continues to deteriorate, some sort of controls may be needed to avoid curtailment of service to existing residential and commercial customers who have no feasible alternative to the use of gas. However, determination of priorities for other classes of customers presents difficulties and especially so on a nationwide basis because of the considerable variation in patterns of gas usage in different regions of the country.[1/]

Above all, proposals for end-use control and/or intrastate sales regulation constitute measures for coping with the gas shortage, not for

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1/ Even so, the FPC has recently acted to establish eight end-use priorities to be applied by all interstate pipelines in the nation during periods when insufficient gas supply necessitates curtailment of service (FPC Order No. 467, issued January 8, 1973), and has advanced a proposal to adopt the same priorities on a national basis respecting use of new gas supplies (Docket No. R-467).

relieving it. On the other hand, if wellhead prices were permitted to rise to realistic market levels, purchasers of gas for interstate markets should again be able to compete with intrastate purchasers, and the tendency for newly available gas supplies to be committed to intrastate markets should diminish.

In short, we do not see expansion of federal regulation over wellhead sales as a promising regulatory strategy for increasing gas supply.[1/] (See further discussion on pages V-37 through V-42.)

4. Modification of Producer Regulation

Leaving aside remedial legislation, the FPC can itself take regulatory actions designed to alleviate the gas shortage. In fact, it has already adopted several measures towards this end. However, there is a limit to how far the Commission can go within the present statutory scheme, and its actions are always subject to appeal and the possibility of court reversal.

A case in point is the FPC's recent adoption on August 3, 1972 of an optional procedure for certificating new gas sales, clearly its most innovative supply-inducement step to date. The new procedure is intended to provide two incentives to domestic production: authorization of sales of gas not previously available to the interstate market at prices in excess of area rates (specifically, at prices "shown to be in the public

1/ No consideration has been given in this report to any additional regulation of transmission or distribution of gas.

interest"), and reduction of future rate uncertainty to the extent possible within the FPC's present statutory powers. The optional procedure -- contrary to some press reports and other pronouncements -- is not a decontrol measure. Not only must all contracts be submitted for FPC review and approval, but use of the procedure is also subject to several restrictions. Moreover, while the FPC proclaimed the intent to provide certainty of rates to the extent of its authority, it recognized that it cannot bind future Commissions not to modify those rates prospectively in the future. Nevertheless, the measure has been vehemently challenged by at least 15 Senators and 20 House members -- as well as certain consumer interest groups -- as a usurpation of the legislative function by seeking to effect, through administrative action, both contract sanctity and deregulation of new gas sales. A group of "Concerned Congressmen" and the American Public Gas Association immediately appealed the FPC's action to the courts. A final decision may be a year or more in the future.

The FPC apparently intends to rely to a considerable extent on the new optional certificate procedure as a vehicle for allowing higher prices. However, in the four months since its adoption, the optional procedure has not generated much response. To date, only four applications have been filed. While one of these applications was certificated relatively promptly, no protest was filed and the rate involved did not exceed the level already approved for sales in an adjacent producing area. The other three applications propose 45¢ rates -- nearly 20¢ higher than the current area rate level -- for sales in South Louisiana. Various parties

have petitioned in opposition, so that more protracted processing will be required. (See pages V-42 through V-48 for further discussion of the optional certificate procedure.)

Another course of action open to the FPC is to raise area rates -- either for new gas sales, or for both new and existing sales -- in order to give greater recognition to market value factors, including prices negotiated for intrastate sales, prices of competitive fuels, and cost and economic trends. This might be done through a reopening of the area proceedings, consideration of petitions to amend the area ceilings, or possibly through the establishment of some type of index permitting periodic price adjustments in accordance with changes in specific economic or cost indicators. However, adjustments within the present area pricing framework are not without drawbacks, and the FPC recently indicated reluctance to proceed in this direction.[1/]

1/ In Opinion No. 639 issued December 12, 1972, the Commission denied an unopposed petition to raise the new gas ceiling rate for Appalachian Area sales in the view that neither perpetuation of the present system of area pricing by contract vintage nor the initiation of a new round of area proceedings offered much hope for alleviating the natural gas shortage. Instead, the Commission urged wider use of the optional certificate procedure. The FPC also commented as follows to criticisms of the present area rate method on grounds of its failure to achieve a workable relationship between supply and demand and its dependence on the use of noncurrent cost data:

> "We appreciate that a uniform national rate for gas sold in interstate commerce, arrived at through rulemaking and tending toward recognition of the commodity value of gas, would not be subject to these infirmities, but before considering this course of action, as an alternative to area rate proceedings, we await the guidance of reviewing courts now hearing appeals of [three area rate decisions]." (Opinion No. 639, Mimeo, pp11-12.)

Given the present area rate system, an increase in rates for existing sales deserves serious consideration since net revenues from such sales provide an important source of cash for undertaking additional exploration and development. Some have opposed any price increases for presently flowing gas without assurance that the additional revenues will actually be devoted to a search for new gas supplies and not diverted to other types of investment. In certain recent decisions, the FPC has responded to this position by providing for increases in flowing gas rates only after specified commitments of new gas reserves to interstate pipelines. Alternatively, in one case, it granted an increase subject to the requirement that the resultant additional revenues be expended in an exploratory program over and above the normal level of expenditures for such activities.

Various other measures could be taken by the FPC to increase the supply of funds available for exploration and development. For example, in a few major cases in the past 18 months, the Commission has adopted a procedure under which refunds determined to be owing by producers to pipelines for excess charges in the past can be worked off by dedicating additional gas reserves to the interstate market. This procedure, or some other type of refund relief conditioned on further exploration, could be applied by the Commission in other cases as well. While waiver of refunds involves a number of equitable considerations, refund monies nevertheless are a potential source of supplemental funds to be directed to exploratory ventures holding promise for future supplies. Consumers could benefit far more by application of the funds in question to a search for additional gas reserves

than by receiving the refund monies either in cash or as a credit to their gas bill.

Still additional funds for gas exploration could be made available by extension and expansion of the FPC's program which permits pipelines to make advance payments to producers for development and production activities and to recover such advances in their rates. This program is presently scheduled to expire on December 31, 1972 but is now under review by the FPC with a view toward its extension and enlargement to include exploratory activities. Also, the Commission could provide encouragement to gas distributors -- as it has to small producers and pipelines -- to search for gas. Several large distributors have established exploration subsidiaries, and some have discovered reserves which they seek to have transported by an interstate pipeline to their service area. One case presenting this situation is now before the Commission.

At some point in the future, EPA might consider a statement of position regarding various regulatory approaches which could be taken by the FPC in an effort to increase wellhead supplies of gas. As identified above and described further in Chapter V (pp. V-42 through V-56), some of the possible means open to the FPC at this time include (a) establishment of higher gas prices reflecting market value and other pertinent economic considerations; (b) flexibility in applying the optional certificate procedure; (c) relief from refunds, subject to use of refund monies in exploration for gas; (d) expansion of the advance payment program; and (e) distributor participation in gas exploration operations. However, in the event EPA should decide to support any of these measures -- all of which involve

higher prices to consumers to increase supply -- this should not be done without thorough prior evaluation of their impact on transportation, distribution and consumption of gas.

5. Acceleration of Offshore Leasing

Clearly, one of the most obvious means for encouraging expansion of natural gas supply is to accelerate, and regularize, the leasing of lands on the Outer Continental Shelf. OCS lands are estimated to contain at least 20% of total U.S. potential gas reserves excluding Alaska (and 40% including Alaska), yet only about 1% of the federal offshore area has been leased to date. The Interior Department has recognized the need for accelerated leasing and is currently going forward with a plan to hold two general lease sales annually over a five-year period in the Gulf of Mexico. Some delay in this schedule has already occurred due to court litigation over the adequacy of Interior's environmental impact statement. At a minimum, all possible efforts should be made to see that the 10 projected lease sales are conducted without further delay.

Interior's current leasing plan has its principal focus in the Gulf of Mexico, which is reasonable since potential gas reserves in OCS lands off Louisiana and Texas are estimated together to comprise 152 trillion cubic feet, or well over 60% of the total offshore potential (excluding Alaska). Offshore Louisiana, in addition, is already a prolific producing area. However, it is imperative that efforts also go forward to enable leasing in the Atlantic and Pacific OCS areas, and in the Gulf of Alaska, at the earliest possible time. The Atlantic OCS -- estimated by the Potential Gas Committee to contain 36 trillion cubic feet of potential

gas reserves -- is a nearby and geologically promising source of increased domestic supply for the East Coast, already heavily dependent on imports of foreign oil and likely to become also dependent on imports of foreign gas (LNG) in the future. Similarly, the Pacific OCS, with estimated potential gas reserves of some 11 trillion cubic feet, represents an obvious source of additional clean-burning fuel for West Coast states, especially California. Yet, leasing of either the Atlantic OCS, or further leasing of the Pacific OCS, can be expected to encounter substantial opposition on environmental grounds.

It is, of course, understood that OCS leasing should go forward only under stringent environmental safeguards. The danger of oil spills can never be entirely eliminated. However, regulations and enforcement of standards to prevent oil spills are stronger today than ever before and also are under constant review to identify possible improvements. The efforts being taken by the Interior Department to require and enforce strict precautionary measures, and the fact that reasonably safe drilling operations can be conducted on offshore lands, need repeated emphasis to the public. The fact that the petroleum potential in the Atlantic OCS is

deemed to be at least 30 miles from shore should also be stressed.[1/] EPA could make a contribution in this regard.

6. Encouragement of Supplemental Gas Supplies

The most likely sources of nonconventional gas on the horizon at this time for increasing U.S. supply over at least the next decade are: (a) gas from Alaska, primarily the North Slope;[2/] (b) gas imported by pipeline from Canadian frontier areas;[3/] (c) LNG imported by tanker from overseas nations; (d) synthetic gas reformed from liquid hydrocarbons;

1/ While there is some question under international law as to the outer limit of the OCS area subject to U.S. jurisdiction, the 1958 Geneva Convention on the Continental Shelf clearly grants the U.S. sovereign rights to explore and exploit the natural resources of the Continental Shelf to a depth of 200 meters (about 656 feet). The width of the OCS at this depth varies widely in different offshore regions of the United States.

With respect to the Atlantic OCS, the U.S. Geological Survey has described the continental shelf as a submerged platform extending from mean low tide to the break marking the beginning of the continental rise -- with a width varying from less than three miles off southern Florida to about 285 miles off Newfoundland, and somewhat less than 600 feet in depth at most places. (Geological Survey Professional Paper No. 659, "Geologic Framework and Petroleum Potential of the Atlantic Coastal Plain and Continental Shelf," 1971.)

2/ Substantial gas potential is also believed to exist in the southern part of Alaska, primarily the Kenai Peninsula, where proved reserves were estimated at slightly more than 5 trillion cubic feet at the end of 1971. Gas from this area is now being liquefied and shipped to Japan. At least one West Coast distributor is considering the possibility of a project to bring LNG from the Kenai Peninsula to California.

3/ Assuming continuation of present export policies of the Canadian National Energy Board (which requires retention of sufficient proved reserves in Canada to meet Canadian market requirements for approximately 30 years in the future before permitting exportation of gas), as exemplified by its recent denial of all pending export licenses for lack of exportable surplus, there seems little likelihood of any substantial increase in imports from Canada until sufficient reserves are developed in frontier regions to support new gas export projects.

and (e) synthetic gas from domestic coal. Other possibilities have also been mentioned -- such as nuclear fracturing of tight gas-bearing formations, oil shale gasification and tar sand gasification -- but these appear speculative for some years to come for technological reasons, among others.

Unlike wellhead production of domestic gas, the nonconventional supplemental sources involve a number of different facets of national policy. These considerations include national security questions concerning sources of supply, balance of payments problems, and oil import restrictions. In addition, nonconventional supply projects promise to be very costly to consumers -- certainly far more so than the cost of domestic gas now and probably still more so for the most part even with an increase in domestic gas rates to market clearing price levels. In short, the regulatory encouragement to be given to supplemental supply sources -- which ones, to what degree, and when -- requires a careful evaluation of a mix of interrelated factors.

From the standpoint of national security, coal gasification and Alaskan gas are the most advantageous. Assuming transportation of Alaskan gas via Canada, various Canadian controls would be exercised, but, once gas was flowing, the danger of interruption of supply seems remote. The same observation pertains with respect to Canadian gas transported from such frontier areas as the Mackenzie Delta in the Northwest Territories, the Arctic Islands and eastern Canada offshore. As to importation of LNG from overseas, the bulk of the world's estimated gas reserves -- exclusive of North America -- are located in the Soviet Union,

the Middle East and North Africa. Each of these area sources could be interrupted in the event of international political or military problems. While the consequences of such interruptions could be mitigated over time by achieving a maximum diversity of LNG sources, nevertheless, a cutoff of supply for any significant period could cause severe problems for particular pipelines or distributors which became heavily dependent on imported LNG.

Coal gasification presents little or no balance of payments problems, nor does Alaskan gas if transported by pipeline in Alaska and by tanker to the West Coast (assuming tanker construction in domestic shipyards). Some balance of payments considerations would be involved in the pipelining of Alaskan gas through Canada. Projects based on importation of gas (or LNG) or liquids for purposes of manufacturing gas raise greater problems in this regard. However, in the case of gas imports, these problems would be diminished to the extent that underlying foreign facilities utilized equipment and materials purchased in the United States.

Considered from a capital requirements standpoint, reformer gas projects based on naphtha feedstocks would appear to be the least costly of the various alternatives at this time.[1/] For example, the Gas Arctic-Northwest Project under study to transport North Slope gas to the Manitoba-Minnesota border is currently estimated to cost $5 billion for a capacity of 3.5 billion cubic feet per day -- or more than $1.40 per cubic foot per day. The El Paso Algeria project to import 1 billion cubic feet per day

1/ Such projects also offer the advantage of a shorter lead time than other supplemental sources of supply. Reformer plants using naphtha can be built in two years or less, as compared with roughly four years for large-scale LNG import and coal gasification projects and still longer for a project to connect North Slope gas.

is estimated to involve a total capital investment of over $1.6 billion (including facilities in Algeria, LNG tankers, and related regasification, storage and pipeline facilities in the U.S.) -- or about $1.60 per cubic foot per day. A coal gasification project recently submitted by El Paso to the FPC contemplates an even higher capital cost -- approximately $1.70 per cubic foot per day of capacity. By contrast, various gas reformer plant proposals filed with the FPC to date indicate a capital investment ranging between about 15¢ and 34¢ per cubic foot per day of capacity.

While the above comparisons are necessarily imprecise because of the tentativeness of many of the underlying cost estimates, they are nonetheless indicative of the vast amounts of capital required to bring about Arctic pipeline, coal gasification and major base-load LNG importation projects. Because of lower capital investment requirements, naphtha-based reformer projects could be implemented by more and by smaller companies to obtain base load or seasonal supplies. At the same time, it should be pointed out that such projects, in general, do not offer a cheaper source of gas to consumers in terms of cost per unit of supply. On the basis of the year-round projects announced to date, the estimated costs per unit of output range from 77¢ to $1.42/Mcf. For seasonal projects, unit costs are estimated in the range of $1.30 to $1.80/Mcf. The bulk of these costs is attributable to the cost of naphtha feedstock which, according to evidence submitted in the FPC, accounts for about 75% of the tailgate cost of reformer gas.

Aside from sensitivity to feedstock costs, a major disadvantage of naphtha-based reformer plants is their dependence on oil product

imports. While some synthetic gas projects now under consideration contemplate use of domestic feedstock, most naphtha produced in domestic refineries today is consumed in the manufacture of gasoline and military jet fuels. Therefore, the naphtha reforming route would require substantial imports of a refined crude oil product to produce gas which would doubtless exceed the energy equivalent cost of crude oil. In addition, this route would result in increased reliance on foreign refining capacity.

An alternative and probably more desirable route is the importation of crude oil to produce naphtha in domestic refineries, for subsequent conversion to synthetic gas, and low sulfur residual fuel oil. Several proposals of this nature have been outlined. In general, lead times for such projects are estimated to be somewhat longer and capital costs higher than for projects based on gasification of naphtha or lighter liquid hydrocarbons. However, the advantages of this course of action, compared with the importation of naphtha, include (a) encouragement, rather than discouragement, of domestic refining capacity; (b) procurement of two needed fuels rather than only one, with concomitant benefits of interfuel competition; and (c) the ability to use high sulfur crude oil as the basic refinery input.

The above discussion is intended to illustrate the myriad of policy issues which bear on supplemental supply projects. These issues must be resolved within a national policy context and cannot be viewed from the standpoint of gas supply maximization alone.

Still another issue has recently come into prominence with the FPC's decision last June approving the importation of 1 billion cubic feet per day of Algerian LNG by three major interstate pipelines serving the East Coast. This issue -- which affects not only imported LNG but also all other high-cost nonconventional supply supplements (and conceivably new high-cost domestic production as well) -- is whether such supplements should be sold at incremental prices (i.e., at the full cost of the incremental supply) or at rolled-in rates (i.e., at the average cost of all supplies).[1/] Traditionally, pipelines in the U.S. have followed the practice of rolled-in pricing. Over the years, this has resulted in efficient use of capacity, avoided complex problems of allocating particular supplies to particular customers and also avoided abrupt changes in prices for new supply acquisitions at higher costs. Continuation of this system, however, has now been placed in doubt by the FPC's decision requiring that the three pipeline importers of the Algerian LNG sell this supply only at incremental rates.

The basic rationale in favor of incremental pricing is that a new supply which cannot be sold at its full economic cost is economically infeasible. While this argument has appeal from a theoretical standpoint, it presents serious difficulties when considered in light of pipeline

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1/ Actually, two levels of sales are involved. First are sales to customers -- distributors and direct industrial customers -- of pipeline companies proposing to import LNG or obtain other high-cost increments of supply. Second are sales by distributors to their customers, i.e., ultimate consumers. For the moment at least, the controversy has narrowed to the method of pricing by pipeline companies to distributor and direct customers.

market realities today. Specifically, a consistent application of incremental pricing principles to all new gas supply sources costing in excess of the rolled-in average cost of a pipeline's existing systemwide supplies would create a host of administrative problems but, even more important, could limit and reduce the amount of new gas supplies for U.S. markets. This is because there are only limited markets at this time prepared to incur the risk of contracting for and then selling supplemental gas supplies at a multiple of historically prevailing gas prices. Thus, incremental pricing threatens the overall marketability of nonconventional gas supplements and thereby could be detrimental to EPA's pursuit of an enhanced supply of gas.

It might be argued that incremental pricing of new supplies would be justified under certain conditions and in certain situations in the future. However, the issue is complex and requires a thorough evaluation by the FPC of the nature of individual pipeline markets, whether supplemental gas is sought to maintain deliveries to existing markets or expand deliveries, alternative sources of supply, and load balancing means.[1/] It is recommended that EPA take no position on any widespread application of incremental pricing until such an evaluation is made and subjected to critical review.

1/ No such evaluation was attempted in the one case where the incremental principle was adopted. In fact, no evidence was even submitted on the subject in that case.

Optimal Strategy and Cost Effectiveness Estimates

While a number of alternative strategies are available to EPA, the optimal strategy is found to be an incentive structure which would allow the price of new gas contracts to be fixed by reference to the marketplace. This would best be achieved by amending the Natural Gas Act to deregulate field prices of gas produced in the United States and sold under new contracts. The objective could also be attained, with lesser effectiveness and a greater time lag, by amending the Natural Gas Act to instruct the FPC in its continuing regulation of field prices of gas to grant "contract sanctity" and to determine reasonable new gas prices by reference to economic factors in the marketplace, not by reference to cost of service.

Under either alternative, the objective would be to allow new gas prices to reach a "market clearing level," the commodity value level. But, at the same time, increased cash flow would be needed in each case to support the expansion of exploration and well drilling activity which would result from increased incentives provided by allowing new gas prices to reach commodity value levels. One method of increasing cash flow for this purpose would be to raise prices for flowing (old) gas. However, the extent to which higher flowing gas prices would actually generate the funds needed to expand exploration (i.e., be channelled to this end) would largely depend on producing companies' evaluation of the prospective return offered by the new gas prices compared with those offered by alternative outlets for investment capital.

The contrast between the projected production of gas in the Lower 48 States under existing FPC area price ceilings, and the optimal solution afforded by commodity value pricing of gas in the field, is estimated on the following table.

FORECAST OF GAS PRODUCTION IN THE LOWER 48 STATES[a/]
(Trillion Cubic Feet at 1000 Btu/cf)

	Based on Current Area Prices b/	Based on Commodity Value Pricing Assuming Elasticity of Supply at +0.45	+0.75	+1.0
1977	21.4	23.1	24.2	25.2
1982	19.3	24.1	27.5	30.1

a/ After exclusion of field use.
b/ Based on the Federal Power Commission estimate set out in National Gas Supply and Demand, 1971-1990, February 1972.

This increased production of gas will directly offset the projected deficiencies in low sulfur coal and oil availability, and doubly so, if additional supplies of fuel oil will be required in the future to fulfill shortfalls in gas demand caused by declining gas production projected on the assumption of a continuation of current FPC area price ceilings. There is thus a volumetric benefit of increased gas production from the point of view of reducing sulfur emissions in the United States. An equivalent expression in dollars can be estimated by reference to the sulfur tax proposed by bills submitted in 1972 to Congress, summarized on the next page.

ESTIMATED BENEFIT OF AN INCREASED GAS SUPPLY IN THE UNITED STATES WITH RESPECT TO REDUCTION IN SULFUR EMISSIONS a/

	Increase in 1982 Gas Supply Resulting from Commodity Value Pricing Commencing January 1, 1973 b/	Cost Benefit in 1982 if the Increased Gas Supply Replaces	
		High Sulfur Coal	High Sulfur Oil
	(Trillion Cubic Feet)	(Million Dollars)	
Maximum	10.8	$3,100-4,147	$2,236-2,970
Minimum	4.8	1,382-1,843	994-1,320

a/ Benefit based only on dollar value of sulfur tax. Other factors such as price of fuel and equipment costs will also affect costs to consumers. National considerations, such as balance of payments and security of supply, are also relevant.

b/ Supply range reflects alternative elasticity of supply assumption ranging from +0.45 to +1.0.

There would also be other benefits. The gas pipeline and distribution industry would benefit from increased throughput or utilization of existing capacity. Without allowing gas prices to achieve commodity value levels, natural gas production in the U.S. will decline. The high proportion of total cost represented by fixed costs (costs which do not vary with output) in pipeline and distribution operations results in diseconomies of scale with declining throughput. Cost per unit of throughput increases as utilization of capacity declines.

In addition, natural gas prices fixed by reference to the market would benefit the energy industry because of the interrelationship of gas with oil, both in terms of exploration effort and corporate structure. The search for gas has become increasingly directional in recent years. Notwithstanding this fact, the price of gas, like the price of

oil, makes a contribution to the search for hydrocarbons. To a non-quantifiable degree, commodity value prices will act to increase supplies of associated-dissolved gas resulting from increased domestic crude oil production.

Another direct benefit of commodity value pricing for gas would be the contribution to the U.S. balance of payments. Each Mcf of gas discovered due to the greater exploration effort under commodity value pricing would accordingly reduce the need to import oil or gas from other countries.

CHAPTER III - REGULATORY BODIES AFFECTING SUPPLY OF GAS

The purpose of this chapter is to identify, and briefly describe the role of, the principal state and federal regulatory agencies which affect the supply of gas in the United States.

A. State Regulation

Gas supply is affected by three basic types of state controls: conservation regulation (applicable in greater degree to oil, but also to gas), leasing of lands (again applicable to both oil and gas), and regulation of local sales. In general, none of these areas of regulation are deemed at this time to present any material barrier to the development of supply. However, the extent to which public opposition in coastal states is able to block leasing or drilling of potential petroleum-bearing lands on environmental grounds could prove to be a major exception.

Also reviewed here are some measures being taken by state regulatory bodies with respect to restrictions on new and expanded gas service by distributors, ordering of service priorities in the event of curtailment, and other measures designed to both reduce demand and encourage supply -- all in response to the developing natural gas shortage.

1. Conservation Regulation

Virtually all producing states exercise a variety of conservation regulations aimed primarily at preventing physical waste of oil and gas. Another purpose is to protect correlative rights of property owners, i.e., rights to an equitable and fair share of oil and gas produced (such share being based generally on the proportion of recoverable reserves

underlying each owner's property to total recoverable reserves in a pool). The regulations relate, among other things, to well completion techniques and equipment; spacing of wells; pooling of tracts; unitization of reservoirs and portions thereof; limitation of production to resonable market demand; allocation of allowable production to pools and among wells in a pool; secondary recovery operations; and protection against land and water pollution as a result of oil and gas drilling and production.[1/]

State conservation laws date from 1878 when Pennsylvania passed the first statute dealing with the casing and plugging of individual wells. More comprehensive regulation developed in the early 1930's when excess supply became a chronic problem in the major oil producing states and crude prices dropped sharply. Large new discoveries, especially in Oklahoma and Texas, aggravated the marketing chaos. Voluntary agreements among operators in some of the more prolific fields met with little success, and martial law had to be imposed on occasion in Texas and Oklahoma

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1/ The coordination of state conservation regulations is provided by the Interstate Oil Compact Commission (IOCC), created in 1935 pursuant to the Interstate Compact to Conserve Oil and Gas. The Compact came into being through a Joint Congressional Resolution which provided for a two-year term. The Compact has been regularly extended by Congressional action for two or four-year periods ever since. The U.S. Attorney General is required to report annually on the effects of oil conservation controls on oil industry competition and price behavior.

The IOCC consists of the Governors of 29 member producing states plus a number of standing committees. The work of the IOCC is largely carried on at its semi-annual meetings, with meetings of the Executive Committee in the intervals. Action is most often taken in the form of resolutions adopted at meetings of the full Commission or the Executive Committee. Those of significance are usually concerned with aspects of federal policy affecting oil and gas which are deemed to involve the conservation interests of the states.

to control the deteriorating situation. In 1931, for example, Texas deployed the state militia to close all wells in the state.

This situation led to the formulation of rules in the various states for limiting production to reasonable market demand. The various state prorationing laws received federal sanction in 1935 with the passage of the Connally Hot Oil Act which prohibited the interstate shipment of oil in violation of any state law (i.e., in excess of state allowable production).

State regulation of production through market demand prorationing has primarily affected the production of oil. Twelve states have statutes defining waste as the production of oil in excess of reasonable market demand, and authorizing limitation of production to demand. But, only six of the states -- Kansas, Louisiana, New Mexico, North Dakota, Oklahoma and Texas -- have ever enjoyed a productive capacity materially in excess of market demand for any substantial period of time. Thus, it is in these states where market demand prorationing has been applied in past decades. Today, however, there is little or no excess oil producing capacity in any of these states. In the two principal producing states, Texas and Louisiana, monthly allowable production of oil has been authorized at maximum efficient producing rates of the wells for several months (with the exception of a few fields held to lower rates because of reservoir problems or limitations on downstream facilities). Three other states (Oklahoma, Kansas and New Mexico) have been producing essentially at 100% -- or more -- of maximum efficient well rates for two or more years.

With respect to natural gas, production is of two principal types: (a) casinghead, solution or gas cap gas which is associated with oil and produced from oil reservoirs; and (b) gas produced from "non-associated" reservoirs. The production of associated gas depends on the rate of oil production[1/] and is affected by any market demand restrictions applied to oil. The production of nonassociated gas -- which has accounted for an increasing proportion of total gas production over the years (77% in 1971) -- is primarily controlled by the rate at which gas is purchased.

Most state regulatory agencies do not attempt to determine state-wide market demand for gas. (Only two have procedures for doing so, Kansas and Oklahoma.) However, some states in the past have periodically required gas nominations on a reservoir basis from purchasers or producers, or both, and then used these nominated volumes to determine allowable production by reservoir.

A few states have attempted in the past to set minimum rates for wellhead sales of gas -- purportedly in an attempt to prevent flaring and waste of gas. The most notable examples are Oklahoma and Kansas. In each case, however, the U.S. Supreme Court reversed the minimum price laws as an invalid interference with the exclusive jurisdiction of the FPC to regulate the price of gas sold by producers for resale in interstate commerce.[2/]

1/ However, over the years, the states have adopted increasingly stringent regulations against the flaring of casinghead gas.

2/ Natural Gas Pipeline Co. v. Panoma Corp., 349 U.S. 44 (1955); Cities Service Gas Co. v. State Corporation Commission of Kansas, 355 U.S. 391 (1958).

Recently, this controversy has been revived with an order issued on October 5, 1972 by the Oklahoma Corporation Commission prohibiting the production of gas at prices less than 20¢ as wasteful.[1/] (For gas produced at depths greater than 15,000 feet, the Oklahoma Commission declared production at prices less than 25¢, 35¢ and 50¢ -- depending on depth -- to be wasteful.) In the order, the Oklahoma Commission asserted that it was not fixing a minimum price or ordering the purchase or sale of gas at any price. Rather, it was merely exercising its authority to enforce rules for the prevention of waste. Hearings were said to have shown that an unreasonably low price for sale of gas encourages production at progressively higher rates to offset rising operating costs, thus causing damage to reservoirs and a consequent loss of recoverable reserves. Further, according to the State Commission, wells are being plugged and abandoned in Oklahoma while they are still capable of producing substantial volumes due to uneconomical prices. For these reasons, the State Commission said it will order wells to be shut in if gas production therefrom is sold at prices considered "wasteful."

The above action of the Oklahoma Commission has already been appealed to the State Supreme Court by several gas producers and gas purchasers. Also, a confrontation with the FPC is inevitable. Relying on previous Supreme Court holdings, the FPC recently rejected some 35 rate increases to 20¢ or higher filed in compliance with the state order. It has also filed suit in a Federal District Court to enjoin enforcement of the order. The FPC takes the position that, although the Oklahoma order

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1/ Oklahoma Corporation Commission, Order No. 93381, Cause CD No. 34596, issued October 5, 1972.

is framed in terms of waste prevention and seeks to avoid the "minimum price" stigma, its essential effect is the establishment of minimum prices and hence an unlawful burden on interstate commerce. Given the past judicial precedent, the ultimate outcome of the measure would seem very much in doubt.

2. Leasing Authority

Producing states all have authority to lease state lands. In general, leases are awarded at public auction to parties offering the highest cash bonus, and provide for a fixed royalty to the state on all oil and gas produced. Otherwise, state leasing regulations and requirements vary greatly from state to state, precluding any meaningful generalization.

In some states, royalties from production on state lands are a significant source of state revenue. During the 1960's, both Texas and New Mexico sponsored testimony in various area rate proceedings in the FPC stressing the importance of such revenues to the respective states -- as well as revenues from taxes imposed on the production of oil and gas. In Texas, for example, certain state agencies own substantial producing acreage -- over 10 million acres in the Permian Basin and Gulf Coast areas alone -- the income from which is used to support the educational system of the state. The same is true in New Mexico which owns approximately 9 million surface and 13 million mineral acres of lands, generating about $4 million of gas royalty income in fiscal 1971.

The State of Alaska represents a somewhat special situation. Among other things, the amount of state-owned lands in known petroleum

producing basins is many times larger than that of any other state. In addition to offshore lands covered by the Submerged Lands Act of 1953, Alaska was granted the right to select about 103 million onshore acres of land from the Federal Domain by the Alaska Statehood Act of 1959. During the early and mid-1960's, Alaska selected about 28 million acres, including that portion of the Arctic Slope where the Prudhoe Bay Field was subsequently discovered in 1968. Selection of the remaining 75 million acres is presently in abeyance due to a freeze imposed by Federal Government in 1966 on further cessions of land to the state (and further leasing of federal lands) pending settlement of Alaskan native land claims.

In September 1969, the State of Alaska held the largest lease sale in U.S. history, receiving nearly $900 million in bonus money for 450,000 acres in the Prudhoe Bay area. A large part of this acreage had previously been offered for sale by Alaska in 1964 and 1965 -- prior to the Atlantic Richfield-Humble Oil & Refining discovery in 1968 -- but received no bids at that time. A drawback to immediate further leasing of North Slope acreage is the continuing uncertainty over the proposed Alyeska pipeline and the lack of market outlets until that or some other pipeline is built.

Also, until Prudhoe Bay oil can be produced and marketed, no gas can be made available from the North Slope since all proven gas reserves discovered to date in the area are associated with oil. Aside from problems involved in the construction of an oil pipeline, additional problems and uncertainties exist with respect to the construction of a gas pipeline. These uncertainties are discussed further in Chapter V.

In general, a basic objective of the states in the past has been to lease lands in order to maximize revenues. Except perhaps for local situations, there has been little pressure to restrict leasing and development of potential oil and gas lands. Recently, however, environmental considerations -- the threat of oil spills in particular -- have caused various state legislatures to seek to halt or ban leasing and drilling activities on certain offshore lands.

Environmental concern in California dates back to 1955 when, as a result of conservationist pressure, the state created an offshore marine sanctuary out to the three-mile limit and for 16 miles along the Santa Barbara coast.[1/] However, in the ensuing years, California leased nearly all state offshore lands outside the sanctuary between the Ventura County line and Point Conception, as well as other submerged lands off its coast.

In early 1969, after a major oil spill on a federal lease in the Santa Barbara Channel, the State of California declared a moratorium on well drilling in all waters under its jurisdiction. Several operators have applied in recent months to conduct further drilling on state leases in an attempt to end the ban. In support, they stress major improvements during the previous two years in techniques and equipment to contain and clean up any oil spill which might occur, as well as a greatly improved capability to drill in offshore areas with little risk of accident. Given

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1/ Cunningham-Shell Tideland Act, Section 6871.2, California Public Resources Code (1955).

the development of these techniques, they contend that further prohibition of offshore drilling is indefensible, especially in view of California's critical need for oil and gas supplies. Nevertheless, the State Lands Commission -- while permitting some sidetracks (wells bottomed less than 100 feet from the original hole) and some redrills (wells bottomed more than 100 feet from the original hole) -- has thus far granted permits for the drilling of only two new wells (both infill development wells).

Moreover, in the City and County of Los Angeles, which overlie large oil and gas pools (both offshore and onshore), public opposition to recent applications for drilling permits in coastal areas has been intense. For example, it took many months of effort before Occidental Petroleum finally won permission from the Los Angeles City Council in October 1972 to drill a well in the Pacific Palisades area near the coastline -- this permission having first been denied in an action reversed by Mayor Yorty.

On the East Coast, similar pressures are now building up against offshore leasing and drilling. For example, in New York, several bills were introduced in the State Legislature this past year to ban oil and gas well drilling in the Atlantic Ocean off Long Island and/or adopt other measures aimed at environmental protection of offshore lands. From a geological standpoint, the sedimentary structures of greatest interest in the Atlantic offshore area are substantially seaward of the three-mile limit generally applied to state lands. However, the Original Thirteen

States presently have a suit pending in the U.S. Supreme Court before a Special Master[1/] claiming that, under their original charters from England, their marine boundaries extend as far as 100-200 miles from their coastline.

Two bills were passed last spring by both houses of the New York Legislature but subsequently vetoed by Governor Nelson Rockefeller. One bill would have prohibited the leasing of any offshore lands for oil or gas extraction within three miles of the New York coastline (or such other boundary as may be ultimately determined to be subject to state jurisdiction). In vetoing this bill, Governor Rockefeller stated that the nation's growing energy needs may make it desirable to permit drilling off New York shores at some future time, and that the State Commissioner of Environmental Conservation has adequate powers to insure that any such drilling will be consistent with the need to protect the state's marine sanctuaries and recreational areas. Further, he added:

> "A large share of potential domestic oil reserves are thought to lie in offshore deposits. If every coastal state were to react automatically and negatively by placing outright prohibitions on the development of these potential reserves, our nation might face severe energy shortages in the not too distant future. This bill represents that kind of automatic and negative reaction. It could well lead to similar action elsewhere and seriously inhibit attempts to achieve a balance between environmental interests and the need for legitimate gas and oil exploration. The bill should, therefore, be disapproved."

The second bill passed by the New York Legislature authorized the adoption of regulations for the protection of marine fishery resources within a distance of 200 miles from the New York coastline or to a depth of

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1/ A Special Master is an individual designated as a special officer or representative of the Court with power to take testimony and determine facts in particular situations.

100 fathoms, whichever is the greater. This bill was vetoed by the Governor in view of current litigation concerning the reach of national and state jurisdiction over territorial waters.

As indicated in another section, environmental opposition to federal sales of offshore oil and gas lease sales has been a significant cause of delay in petroleum development in the past few years. Opposition of the more vocal conservationist groups has been widely publicized. The above-described recent experiences in California and New York illustrate that, on a state level as well, public opposition on environmental grounds poses a significant barrier to the development of offshore hydrocarbon supplies.

3. Rate Regulation

The rates and terms of sales by privately owned gas utilities are regulated by state authorities in all but three states. The three exceptions are Minnesota, Nebraska and South Dakota where municipalities grant permits and set rates for sales of gas. In Texas, municipalities or counties have primary rate jurisdiction, but the state commission has appellate jurisdiction.

Rate regulation by the states is based on the cost of service approach, with the objective of permitting each utility to recover prudently incurred costs plus a fair return on investment. Utility regulation in general is surrounded by a long history, and differences exist between the states as to allowable costs and determination of the investment base (rate base). Thus far, however, neither this history nor the type of present

regulation by the states has any appreciable effect on the total supply of gas.

In addition to rate regulation, most state commissions exercise authority over the initiation of service (37 states), construction of additional facilities (26 states) and abandonment of facilities (43 states). Further, virtually all state commissions have authority to establish safety and service standards and to require line extensions in service areas.

4. Actions Directed to Gas Shortage

During the past few years, state regulatory agencies have become increasingly involved in actions designed to respond to existing or expected natural gas shortages. These shortages have developed over wide areas of the nation due to inability of an increasing number of interstate pipeline suppliers to maintain existing levels of gas delivery to customers, coupled with the inability of nearly all interstate pipelines to expand deliveries to meet demand growth in market areas. (Curtailments by interstate pipelines are discussed in Chapter IV, pages IV-45 through IV-54.)

For the most part, the state actions take the form of considering limitations on new and increased service by local distributors and, in the event of insufficient supply to meet existing gas requirements, priorities of service to govern curtailments. However, a number of states have also taken other measures both to conserve existing supplies of gas and to encourage expansion of gas supply. Such measures include orders banning promotional advertising; approval of higher rates to interruptible and large industrial customers; encouragement to use alternate fuels; efforts to

augment domestic gas production by permitting distributors to invest in exploration and development; support for coal gasification and other R&D projects; directives to expand underground storage or other peak shaving facilities; participation in hearings and/or proceedings before the Federal Power Commission, other federal regulatory agencies and Congress; and requirement of periodic supply reports by natural gas companies within the state.

The various actions already taken, or under consideration, by the different states are summarized in Table III-1 on the following pages. The summary is based on a survey undertaken in late 1971 by the National Association of Regulatory Utility Commissioners (NARUC) of responses by state agencies and intrastate distributors to gas shortage problems. The NARUC report was published on February 29, 1972.[1/]

Table III-2 describes the approaches adopted in different states with respect to restrictions on new and additional service by distributors and curtailment priorities. The summary here rests on the NARUC study noted above, as supplemented by independent surveys conducted by Foster Associates and the Gas Appliance Manufacturers Association.

1/ NARUC "Survey of Actions by State and Federal Regulatory Agencies and Intrastate Natural Gas Distributors to Meet Natural Gas Shortages," February 29, 1972.

A subsequent survey of state regulatory actions by Foster Associates does not permit updating of the NARUC on a comparable basis. Consequently, Table III-1 should not be regarded as a totally up-to-date compilation but rather as an indication of the broad variety of measures which the states are implementing to cope with the growing shortage of gas supply.

NARUC SURVEY OF 42 STATES AND THE DISTRICT OF COLUMBIA
Action by Regulatory Agencies and Natural Gas Distribution Companies
To Meet Existing or Possible Future Natural Gas Shortages
February 29, 1972

Action	Number of States: February 1972	Number of States: Future[1/]	Names of States[2/]
To Conserve Natural Gas Supply			
1. Curtailment in time of shortage			
a. Curtailment of new or added service	13	4	Conn., Del., (D.C.), (Fla.), Ill. Ind., Md., Mich., Mo., N.H., N.Y., N.C., Ohio, (Tenn.), Va., Wis., (Wyo.)
b. Priorities for new or added service	8	4	Calif., Ill., Mich., Mo., (Nev.), N.H., (N.J.), N.Y., N.C., (S.C.), (Tenn.), Wyo.
c. Priorities for curtailment of existing service			
Industrial	16	4	Ariz., Ark., Calif., Conn., (D.C.), Iowa, Mich., Md., Mo., (Mont.), Nev., (N.J.), N.Y., N.C., Ohio, (Pa.), S.C., Vt., W.Va.
Commercial	13	3	Calif., Conn., (D.C.), Iowa, Mich., Md., Mo., (Nev.), N.J., N.Y., N.C., Ohio, (Pa.), S.C., Vt., W.Va.
Steam-electric	1	1	Calif., (Nev.)
Residential	4	1	Conn., (D.C.), Mich., N.C., Ohio
Interruptible	12	4	Ariz., Calif., Colo., Ill., Kan., Md., Mo., N.H., (Nev.), (N.J.), (S.C.) Tenn., (W.Va.), N.Y., N.C., Wyo.
d. Incorporation of curtailment or service priorities in utility tariffs	7	1	Ark., Calif., Iowa, Mo., N.C., Pa., S.C., (Tenn.)
2. Expanded use of alternate fuels			
a. LNG	7	-	Calif., Conn., Del., Ill., Mass., Mich., Ohio
b. Nuclear energy	1	-	Calif.
c. Oil, liquefied petroleum, liquefied propane, synthetic gas	8	-	Ariz., Calif., Conn., Ill., Mass., N.Y., N.C., Ohio
d. Coal gasification research and development	5	-	Calif., Ill., Mich., N.Y., Ohio
3. Advertising and promotion			
a. Advertising to inform the public on conservation of gas	1	2	(N.J.), Okla., (S.C.)
b. Prohibition of specified promotional practices	6	-	Conn., Del., Ill., Mich., Ore., Pa.
4. Higher rates to interruptible or large industrial and commercial customers	1	2	Kan., (Okla.), (Utah)

NARUC SURVEY OF 42 STATES AND THE DISTRICT OF COLUMBIA
Action by Regulatory Agencies and Natural Gas Distribution Companies
To Meet Existing or Possible Future Natural Gas Shortages
February 29, 1972

Action	Number of States February 1972	Number of States Future[1/]	Names of States[2/]
To Increase Available Natural Gas Supply			
1. Exploration for natural gas			
a. Intrastate for domestic U.S.A. and offshore	6	-	Calif., Mich., N.Y., Ohio, Okla., Wyo.
b. Foreign	3	-	Calif., Mich., Ohio
c. Investment or loan authorization for exploration for gas	2	-	Calif., Ill.
2. Expanded underground storage or other facilities for peak shaving	3	-	Calif., Ill., Ind.
3. Increased gas production allowables	2	-	Okla., Tex.
Other Measures to Conserve and/or Increase Natural Gas Supply			
1. Gas supply reports by natural gas companies to regulatory agencies	7	2	Ark., Calif., Del., Ill., Mich., N.C., (N.J.), Pa., (Wis.)
2. Intervention and participation in FPC proceedings affecting gas	9	-	Ark., Calif., Ga., Ind., La., Mich., N.Y., Tex., Utah
3. Regulatory agency policy orders prescribing conservation and curtailment procedures	6	-	Calif., Del., Nev., N.J., N.Y., N.C.
4. Regulatory agency appeals to or appearances before U.S. Congress and federal agencies	2	-	Mich., N.Y.

1/ Contingency plan, pending application, or possible future action.

2/ Names of states in parenthesis are those planning future action.

Certain states have approached these matters on a statewide basis. For example, in 1970 or 1971, the regulatory agencies in four East Coast states -- New York, New Jersey, Pennsylvania and North Carolina -- initiated investigations into the adequacy of gas supplies in the respective states, the desirability of promulgating general rules concerning the attachment of new and expanded loads, and curtailment procedures. These investigations ended with the issuance of rules generally applicable to all utilities in the state. Regulatory bodies in other states -- including Illinois, Ohio and Nevada, among others -- have also held statewide hearings.

In a larger number of states, particularly those confronted with the expectation of growing curtailments by interstate pipeline suppliers, authorization has been granted to numerous individual gas utilities to restrict new connections and, if necessary, cut back existing service according to specified plans.

Generally speaking, as Table III-2 indicates, activities of state regulatory agencies in the area of service restrictions and curtailments have been particularly intense in certain eastern and midwestern states with large gas consuming populations and little or no gas production. Notable examples are New York, Pennsylvania, Illinois and Michigan. In the western part of the country, California is unique in having had a formal program concerning gas supplies and curtailments of service for over 20 years.

However, major producing states are also being affected by the gas shortage. In Louisiana, one of the two principal sources of domestic

SUMMARY OF STATE ACTIONS RESPECTING RESTRICTIONS AND/OR CURTAILMENTS OF GAS SERVICE

ALABAMA The Alabama Public Service Commission has ordered distributors to submit plans governing the conservation of available gas supply.

ALASKA (No information available.)

ARIZONA The Arizona Corporation Commission, in 1972, issued a comprehensive set of rules respecting load additions and increases, and curtailment of service priorities. Service to new industrial or commercial customers requesting over 7,000 Mcf per month or 70,000 Mcf per year are prohibited, and increases in service to present industrial and commercial customers above these limits may not be made except on an interruptible basis. Curtailment priorities provide for cutoff first of interruptible deliveries, large industrial users and smaller industrial users.

Some gas operators have curtailed or stopped service to large industrial users under interruptible clauses in their service contracts during periods of extreme gas shortage. Several large electric utilities have installed large oil reserves to supplement natural gas when gas is in short supply.

ARKANSAS The Arkansas Public Service Commission held hearings in 1971 to determine curtailment priorities for Arkansas Louisiana Gas Co., the major gas distributor in the state. An order of priorities was established by the Commission on August 9, 1971. The priorities (from lowest to highest) are: large industries curtailed at Arkla's discretion; industrial boiler fuel users able to use alternate fuels (subject to certain limitations); other industrial deliveries where an alternate fuel cannot be used (except service to prevent plant damage); remaining industrial and all commercial uses; residential and other human needs customers.

CALIFORNIA The California Public Utilities Commission has long had a comprehensive program to assure adequate gas supply and has also taken a number of actions recently to meet the threat of a future natural gas shortage. Since the 1940's, California has required distributors to include curtailment plans for industrial sales in utility tariffs in order to avoid jeopardizing firm service to domestic customers in periods of shortage. In addition, since 1961, the PUC has required all distributors within the state to submit an annual report on existing and estimated future gas supply.

The California Commission has also sought to encourage exploration for new natural gas supplies both in the United States and abroad (including distributor investment in exploration ventures), and has supported the development of use of alternate fuels to supplant or supplement natural gas.

COLORADO The Colorado Public Utilities Commission has not yet taken any specific action to relieve gas shortages or to stretch existing gas supplies.

CONNECTICUT The Connecticut Public Utilities Commission has not issued a general order regarding gas curtailment. However, on August 19, 1971, it approved a plan filed by Connecticut Power & Light Co. for refusing new customers or added loads from existing customers. Specifically, Connecticut P&L was directed to supply minimum additional load requirements of customers in the future according to a system of priorities setting maximum allowable volumes and specifying type of use. Residential and small commercial customers, medium commercial, large commercial and small industrial, and large industrial customers were to be served, in that order, with maximum volumes ranging from up to 500,000 Btu per hour for residential customers to 2,000,000 Btu per hour for large industrial customers.

DELAWARE The Delaware Public Service Commission, in December 1971, ordered Delmarva Power & Light Co. not to provide any additional or increased service to any building, structure or other installation not then receiving gas service -- except to honor contracts entered into prior to that date. However, this additional service is limited to 200,000 Mcf, with the allocation thereof to consider the location of existing lines, the extent to which the structure has been completed and gas burning equipment installed, and certain other factors. Delmarva was also ordered to prohibit any home, building, installation or other structure presently connected to its supply lines to be converted to gas for heating purposes and to cease advertising of gas-fired heating systems and appliances of any kind (except replacements or others which could assist in reducing the summertime valley in gas consumption).

DISTRICT OF COLUMBIA The Public Service Commission of the District of Columbia, in November 1971, issued interim authority to Washington Gas Light Co. to limit sales growth to residential use. However, the PUC denied WG&L's request to restrict new gas sales to single-family residences and instead ordered the company to also serve individually metered apartment house uses. In March 1972, WG&L ceased all new service even to residential customers.

SUMMARY OF STATE ACTIONS RESPECTING RESTRICTIONS
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FLORIDA — The Florida Public Service Commission has taken no action respecting service restrictions or curtailments.

GEORGIA — The State of Georgia has not yet experienced any gas shortage and therefore has approved no curtailment plan, service priorities, or end-use priorities. However, the Georgia Commission has intervened in an FPC proceeding concerning curtailments by Southern Natural Gas Co. which could affect service to Atlanta Gas Light Co.

HAWAII — Hawaii is presently self-sufficient with respect to its gas supply. Its only gas utility company manufactures gas for use on the island of Oahu, and propane is distributed in rural areas from Standard Oil of California's refinery on Oahu.

IDAHO — The Idaho Public Utilities Commission is presently drawing up a policy outlining end-use priorities. Recently, the Idaho Commission met with the Oregon and Washington Commissions, and with El Paso Natural Gas Co. and seven natural gas distribution companies serving the area, to discuss present and future supply of natural gas for the region. A possibility now under study is the development of common peak shaving facilities by distributors in the area.

ILLINOIS — Illinois has a comprehensive program for dealing with the problems of adequacy of gas supply. Among other things, the Illinois Commerce Commission considers: curtailment policies of distributors, programs for restricting new or increased service; expansion of underground storage and peak shaving; prohibition of specified promotional practices; and encouragement of construction of dual-fuel facilities. In addition, the Illinois Commission has authorized investment by utilities in activities to explore for gas, and encouraged the formation of a Coal Gasification Group by seven utilities to conduct research and development work towards a coal gasification plant.

New and additional service by Peoples Gas Light & Coke Co. and Northern Illinois Gas Co., two of the largest distributors in the state, has been restricted for some time.

INDIANA — The Indiana Public Service Commission does not hold hearings on curtailment plans of distributors as many other states do. Rather, state approval is automatic if no objection to a curtailment proposal is filed within 30 days of its submission. Several distributors in the state have volumetric limits on new service, and some have established priorities for curtailing existing service.

IOWA — The Iowa Commerce Commission has issued no orders but maintains contact with local gas utilities which have procedures in their filed tariffs for protecting service to presently attached firm gas customers.

KANSAS — Kansas apparently has given little formal attention to gas service restrictions and curtailments. (A letter to Foster Associates indicated that Kansas relies on FPC regulation of Kansas-Nebraska Natural Gas Co. to control gas supply in the state.) However, Kansas distribution companies have begun to curtail the use of gas not only during the coldest weather, but also at other seasons of the year.

KENTUCKY — The Kentucky Public Service Commission is currently investigating curtailment procedures. At least five distributors have filed curtailment programs.

LOUISIANA — The Louisiana Public Service Commission has issued no general directives on the subject of curtailments. The majority of its gas companies are served by interstate pipelines subject to FPC jurisdiction. The Louisiana Commission has, however, intervened in various proceedings involving the gas supply of United Gas Pipe Line Co. with the objective of obtaining a greater proportion of United's supply for customers in Louisiana.

MAINE — Maine has formulated no plans for curtailment or service priorities with respect to natural gas use. Although the state is now adequately supplied, the Maine Public Utilities Commission is examining future sources of pipeline natural gas, LNG and other alternate gas sources.

MARYLAND — The Maryland Public Service Commission has not developed a statewide program with respect to natural gas shortages, curtailments or priorities, but has issued orders approving curtailment proposals by specific distributors.

SUMMARY OF STATE ACTIONS RESPECTING RESTRICTIONS
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MASSACHUSETTS The Massachusetts Department of Public Utilities plans to review the status of each utility company's gas supply after the spring of 1972 when the extensive program of construction of storage and processing facilities for liquid natural gas and for LPG, which has been under way for several years, is expected to be completed. If the review indicates the need for any curtailment or priorities for gas service, they will be made at that time.

MICHIGAN The Michigan Public Service Commission has considered and approved applications dealing with limitations on new service and curtailment of existing service by several distributors. One order, for example, provided that no new commercial or industrial customers could be added to the utility's system and restricted additional residential customers under a priority system. Another order forbid new residential, commercial or industrial customers in the Southern Division system of Michigan Gas Utilities Co., and also denied a priority petition of the Michigan State Housing Development Authority for priority of gas service for low and medium income housing customers. A third order established a "Controlled Service Program" under which natural gas available to Michigan Consolidated Gas Co. in excess of existing requirements of firm customers will be sold in a manner to ensure satisfaction of its most essential end uses, i.e., according to a schedule of priorities.

The Michigan Commission retains jurisdiction to consider gas service for any customer with a pollution problem which presents an unusual threat to the public health and welfare.

MINNESOTA Minnesota has no agency with authority to control gas supply.

MISSISSIPPI The Mississippi Public Service Commission has issued no orders nor adopted any plan with respect to curtailment of service or end-use priorities during periods of natural gas shortage. Mississippi's natural gas distribution companies have filed no specific overall formalized plans for meeting gas shortages with the Commission, but several major gas companies have included curtailment provisions in their revised tariff rate schedules during 1971.

MISSOURI The Missouri Public Service Commission has issued no general orders relating to curtailment of service, or end-use priorities for natural gas service during periods of gas shortages. However, the Commission has approved tariff provisions for several individual companies establishing priorities for curtailment during periods of short supply, as well as priorities for connection of new service as additional supplies of gas become available.

MONTANA The Montana Public Service Commission has issued no orders regarding curtailment.

NEBRASKA Nebraska has no agency with authority to control gas supply.

NEVADA The Nevada Public Service Commission has held public hearings on a proposed General Order 18, "Natural Gas Service Curtailment Priorities," but a final order has not yet been issued. The proposed general order includes provision for priorities of service in the event of gas shortage in the following sequence: domestic service; commercial firm service; public utility steam-electric generating plant firm service; industrial firm service; commercial interruptible service; public utility steam-electric generating plants interruptible service; and industrial interruptible service.

NEW HAMPSHIRE The Public Utilities Commission of New Hampshire issued no orders and formulated no plans for curtailment of gas service. It has been a standard practice in the state that interruptible loads have the lowest priority and space-heating customers highest priority.

NEW JERSEY The New Jersey Department of Public Utilities Board of Public Utility Commissioners issued Executive Order No. 71-3 (December 23, 1971) establishing standard curtailment rules for distributors in the event of a gas shortage. The order provides for the curtailment of non-residential services in the following order: (1) interruptible customers and customers having dual-fuel capacity, after suitable advance notice; (2) industrial and commercial customers being served under special contracts; (3) firm industrial and commercial customers who have agreed to curtailments, under prior arrangements; (4) distributors' own facilities, to a minimum level; (5) industrial and commercial customers on an involuntary basis under an established priority list, assigned by the utility; and (6) all remaining non-residential customers. The distributors were also ordered to file curtailment plans and to substitute advertising of an "educational" nature in lieu of promotional advertising.

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In January 1972, the New Jersey Board scheduled hearings to investigate priorities for curtailment, sales and advertising practices, and the effect of gas curtailments on the industrial life of the state.

NEW MEXICO — New Mexico is reportedly investigating gas supply and curtailment matters.

NEW YORK — The New York Public Service Commission initiated an investigation in mid-1970 to determine whether any restrictions should be placed on attachment of new customers by gas distributors in view of potential gas supply shortages. On October 26, 1971, the New York Commission issued a decision restricting attachment of all new customers other than residential. Analyzing the supply-demand situation of each of the state's 23 gas distributors in light of supply cutbacks by interstate pipelines serving New York, the PSC concluded that all but two would be unable to secure sufficient gas to meet the reasonable needs of its customers and of persons or corporations applying for new or additional gas service. Accordingly, the New York Commission ordered that (1) no new customers (except one- and two-family homes, and individually metered apartments) be attached unless the utility has a sufficient firm supply of gas to meet all firm customer needs for at least two years following attachment, the customer has facilities to burn an alternate fuel, or the gas is to be used for a commercial or industrial process for which there is no practical or economically feasible alternative fuel; (2) increased service to existing firm customers (other than one- and two-family homes and other individually metered domestic consumers) taking less than 12,000 Mcf annually be limited to a maximum of three years, whichever is less, unless the customer has dual-fuel capacity at least equal to the increment above such ceiling; and (3) increased service to existing customers taking 12,000 Mcf or more annually is to be limited to their highest annual consumption in the last three years in the absence of newly installed dual-fuel capacity at least equal to the increment above such consumption level.

In addition, the New York Commission established a schedule of priorities in the event curtailments are necessary, ordered an end to all promotional activities aimed at attracting new or additional gas load, and directed all gas distribution companies to submit within 60 days detailed plans for new or increased peak-shaving facilities (or advise why no such facilities are being planned).

NORTH CAROLINA — The North Carolina Utilities Commission instituted a rulemaking proceeding in July 1970 to consider service limitations by gas utilities within the state. By order dated July 27, 1971, the North Carolina Commission directed that any gas company placing limitations either on sales to new customers or additional sales to existing customers provide service according to the following priorities (highest to lowest); residential customers who can be feasibly served; small commercial and industrial users with requirements not exceeding 20 Mcf/d; industrial customers using gas as a raw material; large commercial and industrial customers with requirements exceeding 20 Mcf/d; preferred interruptible customers; interruptible customers; dump schedule customers.

The North Carolina Commission also ordered all distributors to install or maintain sufficient peak shaving equipment to meet residential customer needs.

NORTH DAKOTA — (No information available.)

OHIO — The Ohio Public Utilities Commission held hearings in December 1971 respecting possible restrictions on new and increased service. In February 1972, the PUC issued an interim order directing all distributors delivering over 2,000 Mcf/d to cease promotional advertising, submit plans for acquiring or increasing peak shaving and storage facilities, submit curtailment proposals, and report monthly to the state. Several distributors in the state are refusing service to new nonresidential customers, and at least two have been authorized to restrict service to new residential customers.

OKLAHOMA — The Oklahoma Corporation Commission has apparently issued no curtailment orders. However, the Commission is considering the establishment of long-range priorities for natural gas use.

OREGON — The Public Utility Commissioner of Oregon has issued an order curbing sales promotion activities by gas utilities, as well as by electric utilities.

PENNSYLVANIA — The Pennsylvania Public Utility Commission instituted an investigation in March 1971 into the adequacy of natural gas supplies in Pennsylvania. In February 1972, the PUC ordered all gas utilities to (1) file reports on gas deliveries and available supplies immediately and henceforth whenever an estimate in an earlier report changes by 5%; (2) submit curtailment procedures as part of their

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tariffs; (3) refrain from contracting to serve any gas-burning equipment installed after February 15, 1972, except under certain conditions; (4) cease all promotional advertising; and (5) submit proposals for intercompany cooperation to insure reliability of service during periods when demand exceeds supply.

PUERTO RICO — Gas use at present time is limited to propane and butane gas produced by island petroleum refineries.

RHODE ISLAND — The Division of Public Utilities has taken no action requiring utilities to curtail gas sales. Distributors have undertaken voluntary curtailments. Providence requires advance approval for new commercial and industrial hookups.

SOUTH CAROLINA — The South Carolina Public Service Commission has not issued orders relating to curtailment or end-use priorities for natural gas service, nor has there been a statewide program regarding existing or potential natural gas shortages. However, the PSC has approved curtailment policies and/or service priorities for at least two utilities: Piedmont Natural Gas Co. and Carolina Pipeline Co.

SOUTH DAKOTA — South Dakota has no agency with authority to control gas supply.

TENNESSEE — The Tennessee Public Service Commission has not yet taken action on utility company applications for inclusion of curtailment rules and limitations on gas sales in rate schedules. Three companies have proposed priorities for curtailment and service limitations in the event of insufficient gas supply to meet demand. Emergency curtailment plans have been approved for two companies.

TEXAS — The Texas Railroad Commission set a hearing for November 30, 1972 to consider all matters relating to the promulgation of curtailment priorities for gas transported, delivered and sold in the State of Texas.

UTAH — The Utah Public Service Commission is not presently contemplating any action with respect to conserving existing supplies or increasing available gas reserves. Utah's principal supplier recently asked authorization, however, for rate increases to large industrial and commercial consumers, but not for residential service, as a means of effecting restriction of gas sales.

VERMONT — The Vermont Public Service Board has not approved any gas curtailment plans, nor have any been filed with it. The Board, however, has imposed restrictions on advertising and promotional practices by gas and electric utilities.

VIRGINIA — The Virginia State Corporation Commission has wide-ranging powers permitting almost instant curtailment of gas usage when necessary. During 1971, limitations on new customers were ordered for 10 distributors, most limitations permitting new residential customers only. In addition, Virginia is studying the possibility of ordering alternate fuel use by large industries.

WASHINGTON — The Washington Utilities and Transportation Commission has taken no formal action directed toward conserving or enlarging Washington's gas supplies. However, the Commission has met with other Pacific Northwest regulatory agencies, together with the region's gas distribution companies and suppliers, to discuss measures for attempting to solve the gas supply problem beyond 1972.

WEST VIRGINIA — The West Virginia Public Service Commission is presently considering requests by gas distribution companies to approve restrictions on new industrial customers and new commercial customers (other than multi-family structures) and curtailments of deliveries to industrial customers if necessary to protect service to residential customers. New service restrictions and curtailment programs have been authorized for at least two companies.

WISCONSIN — The Wisconsin Public Service Commission deals with gas shortage on an individual company basis. A number of utilities in Wisconsin have filed formal petitions for authority to limit the sale of gas to new customers and additional gas to existing customers, and to curtail deliveries in the event of insufficient supply. In these cases, formal hearings have been held and orders issued granting sales limitation and curtailment authority. In all cases, the company involved is required to submit a periodic report as to its gas supply situation and an analysis of future developments.

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WYOMING	Wyoming at present has no general natural gas shortage and does not foresee one. However, established policy of the Wyoming Commission in times of gas shortage is to discontinue service to interruptible customers first, and to firm industrial or commercial users second, with a view to maintaining service to the residential customer as long as possible. Should Wyoming's industrial progress be impeded by a natural gas shortage in the future, it is thought possible that the legislature might take action to curtail the amount of gas exported from the state.

Source: (1) Foster Associates survey of state actions regarding curtailments and supplies;
(2) NARUC survey of state agency and distributor actions to meet gas shortages, report issued February 29, 1972;
(3) Survey of curtailment plans and agency actions by Gas Appliance Manufacturers Association; and
(4) Press reports.

gas, power plant and other industrial customers dependent on gas supplies from United Gas Pipe Line Co. (an interstate pipeline) have been substantially curtailed over the past few years. Further, plans for a number of new industrial plants in the state have been halted because of the lack of an available gas supply. The Louisiana Commission is taking an increasingly active role in various Federal Power Commission proceedings in an effort to retain a greater proportion of United Gas Pipe Line's supplies within the state.

In Texas, an action of particular significance was the recent scheduling of hearings by the Texas Railroad Commission for November 30, 1972 to consider the establishment of curtailment priorities for gas transported, delivered and sold in the State of Texas. The notice setting the hearing declared: "There is an immediate and urgent need for the development of a statewide standard of priorities for the curtailment of transportation, delivery and/or sale of gas to assure effective control of the flow of gas to the proper destinations to avoid suffering and hardship of domestic consumers, yet to make available to all gas consumers on a reasonable but limited basis during times of needed curtailment to the end that the public will be best served."[1/]

1/ Notice (dated November 16, 1972) of Hearing Relating to the Promulgation of Curtailment Priorities for Gas Transported and Sold in the State of Texas, Oil and Gas Docket No. 20-62,505.

B. Interior Department

1. Leasing of Public Lands

a. Leasing Statutes and Administering Agencies

The authority of the Interior Department to lease federal lands derives from the Mineral Lands Leasing Act of 1920 (onshore lands) and the Outer Continental Shelf Lands Act of 1953 (offshore lands).

The OCS Act provided for federal jurisdiction over the submerged lands lying seaward of those granted to the states. The latter had been generally determined by the Submerged Lands Act of May 22, 1953, which gave the coastal states jurisdiction over such lands to a distance of three miles from their coast lines into the Atlantic and Pacific Oceans and up to nine miles into the Gulf of Mexico if a state's historic boundary prior to joining the Union had been more than three miles from shore or if such a boundary had previously been approved by Congress. The states of Florida and Texas are in this category.

The boundaries of the federal and state segments of the OCS, and hence of the respective jurisdictions, have not yet been precisely defined. The seaward limits remain imprecise, and even the location of the shoreward boundaries is, in some cases (such as off Louisiana), still in dispute. Litigation is currently pending with respect to the jurisdiction limits of the Atlantic States, Florida, Louisiana,[1/] California and Alaska.

1/ See Footnote on following page.

Within the Department of the Interior, the Bureau of Land Management is responsible for the leasing of public lands, while the Geological Survey regulates operating practices. The Geological Survey is also responsible for geological and geophysical exploration on OCS lands. Information provided by the Geological Survey, along with other information, is evaluated prior to leasing in order to identify promising acreage and appraise potential resources. In large part, the Geological Survey purchases geological and geophysical data from private surveyors.

The Interior Department's basic objectives with respect to the leasing and management of publicly owned mineral resources are threefold: to assure orderly and timely resource development, to assure a fair market value return on disposition of public resources, and to protect the environment.

1/ To permit mineral development to proceed pending resolution of conflicting claims, Louisiana and the Federal Government signed an agreement in 1956 whereby the area off Louisiana was divided into four zones extending seaward from the Chapman Line, which is a line generally following the Louisiana coastline established for administrative convenience. Zone 1 extends three miles seaward from the Chapman Line, and Zone 2 continues seaward to a point nine miles from the Chapman Line. Zone 3 includes the area seaward of Zone 2 to a line nine miles seaward of the "Coast Guard Line," and Zone 4 includes all submerged lands seaward of Zone 3. Louisiana has exclusive jurisdiction within Zone 1. Zone 4 and undisputed portions of Zones 2 and 3 are managed by the Federal Government. The portions of Zones 2 and 3 in dispute are controlled by a joint committee with members from the Interior Department and the Louisiana Mineral Board. All revenue from leases in the disputed areas is placed in escrow for distribution at such time as the ownership is finally resolved.

b. Leasing of Onshore Lands

Under the Mineral Lands Leasing Act of 1920, leases are granted both by competitive bidding and by a simultaneous filing system. In the latter case, with a number of applications for the same lease filed simultaneously, the right of priority is resolved by public drawing.

When land is within the known geologic structure of a producing oil or gas field prior to the issuance of a lease, it may be leased only by competitive bidding and in units of not more than 640 acres to the qualified applicant offering the highest lease bonus. Royalty payments are usually 12.5%. The simultaneous filing system is used in areas where research or exploration is required before the presence of minerals can be anticipated. Such non-competitive leases may be as large as 2,560 acres, and the royalty is fixed at 12.5%.

Competitive and non-competitive leases involve primary terms of five and ten years, respectively, with production of oil or gas in paying quantities holding either type of lease thereafter.

Recently, a Department spokesman expressed the opinion that a system of all competitive leasing, with appropriate requirements for exploration and development, would be more responsive to supply and demand and would lead to less holding of leases primarily for speculation.[1/] Interior has proposed reforms to the mineral leasing laws towards this end.

1/ Statement of Harrison Loesch, Assistant Secretary of Interior, to Senate Committee on Interior and Insular Affairs, June 19, 1972.

c. Leasing of OCS Lands

Under the OCS Lands Act, all oil and gas leases are issued on a competitive bidding basis. The present system involves cash bonus bidding by sealed bids, plus payment of a fixed royalty. The acreage of a single lease block may not exceed 5,760 acres, and leases are issued for a primary term of five years and may be held thereafter as long as oil or gas are produced in paying quantities. The Act specifies that in no event shall the royalty on oil and gas be less than 12.5%; actually, all OCS leases issued to date have required a royalty rate of 16-2/3%. Annual rentals are set at $3 per acre for leases offered at general lease sales (unproven areas) and $10 per acre for leases obtained at drainage sales (proven areas).

Since passage of the OCS Act, BLM has conducted 25 sales of offshore oil and gas leases, including 11 drainage sales (in proven areas) and 14 general sales (in unproven areas). The acreage and bonus figures for these sales are shown on Table III-3 on the following page. The pattern of sales has been erratic, with no general lease sales held in eight of the last 19 years and one or two general sales held in the remaining years. In the aggregate, the sales have netted the United States Government cash bonuses in excess of $5 billion. On an acreage basis, two-thirds of the lease sales have involved lands adjacent to Louisiana. Thus far, the only other states involved to any significant extent have been Texas and California.

A measure of the importance of the nation's offshore oil and gas development is the fact that, between 1958 and 1971, production from

OUTER CONTINENTAL SHELF LEASE SALES OF OIL AND GAS

Date	Type Sale	State	Offered Tracts	Offered Acres	Leased Tracts	Leased Acres	Total Bonus	Average Bid per Acre	Highest Bid per Acre
10/13/54	(G)	La.	199	748,000	90	394,721	$ 116,378,476	$ 295	$ 1,220
11/09/54	(G)	Tex.	38	111,788	19	67,149	23,357,029	348	2,209
07/12/55	(G)	Tex.	39	216,000	27	149,760	8,437,462	56	177
07/12/55	(G)	La.	171	458,095	94	252,807	100,091,263	396	2,077
02/26/59	(G)	Fla.	80	458,000	23	132,480	1,711,872	13	16
08/11/59	(D)	La.	38	81,813	19	38,820	88,035,121	2,268	10,442
02/26/60	(G)	Tex.	97	437,760	48	240,480	35,732,031	149	1,026
02/26/60	(G)	La.	288	1,173,223	99	464,046	246,909,784	532	2,502
03/13/62	(G)	La.	401	1,808,276	206	951,811	177,260,305	186	3,201
03/16/62	(G)	Tex.	30	90,720	10	28,800	557,720	19	26
03/16/62	(G)	La.	380	1,780,265	195	927,746	267,775,727	289	3,081
10/09/62	(D)	La.	19	33,855	9	16,178	43,887,359	2,713	8,480
05/14/63	(G)	Cal.	129	669,777	57	312,945	12,807,587	41	455
04/28/64	(D)	La.	28	34,028	23	32,673	60,340,626	1,847	10,490
10/01/64	(G)	Ore.	149	836,134	74	425,433	27,768,772	65	376
10/01/64	(G)	Wash.	47	253,940	27	155,420	7,764,928	50	310
03/29/66	(D)	La.	18	35,993	17	35,056	88,845,963	2,534	6,112
10/18/66	(D)	La.	52	227,898	24	104,717	99,164,930	947	3,128
12/15/66	(D)	Cal.	1	1,995	1	1,995	21,189,000	10,621	10,621
06/13/67	(G)	La.	206	971,489	158	744,456	510,079,178	685	6,500
02/06/68	(G)	Cal.	110	540,609	71	363,181	602,719,262	1,660	11,374
05/21/68	(G)	Tex.	169	728,551	110	541,304	593,899,046	1,097	7,602
11/19/68	(D)	La.	26	46,824	16	29,682	149,868,789	5,049	27,401
01/14/69	(D)	La.	38	96,389	20	48,505	44,037,339	908	2,161
12/16/69	(D)	La.	27	93,764	16	60,153	66,908,196	1,112	6,600
07/21/70	(D)	La.	34	73,360	19	44,642	97,769,013	2,190	8,201
12/15/70	(G)	La.	127	593,485	116	543,898	845,832,785	1,555	12,875
11/04/71	(D)	La.	18	55,872	11	37,222	96,304,522	2,587	18,005
09/12/72	(G)	La.	78	366,682	62	290,521	585,827,925	2,016	21,870
			3,037	13,324,585	1,661	7,436,601	$5,021,262,010	$ 675	

(D) = Drainage sales (proven areas)
(G) = General sales (unproven areas)

Source: U.S. Department of Interior, Geological Survey, Outer Continental Shelf Statistics, 1971; data provided by Bureau of Mines on lease sale held September 12, 1972.

OCS lands rose from about 1% to over 12% of total U.S. production of both natural gas and crude oil and condensate.[1/] (Including state offshore lands, the respective proportions are about 18% and 16%.) Even more important is the fact that only about 1% of OCS lands, or 7.4 million acres out of a total of 682 million acres,[2/] has been leased to date by the Federal Government.

In President Nixon's Clean Energy Message to Congress on June 4, 1971, the Secretary of Interior was directed to accelerate oil and gas leasing on the Outer Continental Shelf both in the Gulf of Mexico and in other promising areas, and to publish a five-year schedule of lease offerings. Pursuant to this mandate, Interior released a tentative five-year schedule for OCS leasing contemplating 10 sales in the Gulf of Mexico through 1975 and public hearings on possible leasing in the Gulf of Alaska

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1/ The bulk of the OCS production is from offshore Louisiana. The breakdown for 1971 is as follows.

	Crude and Condensate (Billions of Barrels)	Natural Gas (Billions of Cubic Feet)
OCS - Louisiana	386	2,634
OCS - Texas	2	127
OCS - California	31	16
Total OCS	419	2,777
Total U.S.	3,478	22,493

Source: Interior Department submission to Senate Committee on Interior and Insular Affairs in connection with oversight hearing held March 23, 1972 on administration of Outer Continental Shelf Lands Act, Table 55.

2/ Includes OCS areas of the Gulf of Mexico, and the Atlantic, Pacific and Arctic Oceans, beyond state jurisdiction to the 200 meter depth limit.

and Atlantic Ocean sometime prior to 1976. The tentative schedule was as follows:

Date	Area and Type of Sale
10/71	Gulf of Mexico (Drainage)
12/71	East Louisiana (General) and Gulf of Mexico (Drainage)
5/72	Louisiana (General) and Gulf of Mexico (Drainage)
11/72	Texas (General) and Gulf of Mexico (Drainage)
5/73	Alabama, Mississippi and Florida (General) and Gulf of Mexico (Drainage)
11/73	Louisiana and Texas (General) and Gulf of Mexico (Drainage)
5/74	Gulf of Mexico (Drainage)
11/74	Louisiana and Texas (General) and Gulf of Mexico (Drainage)
5/75	Gulf of Mexico (Drainage)
11/75	Gulf of Mexico (General and Drainage)

In regard to the above schedule, the first proposed drainage sale was held in November 1971, but further sales have been delayed. The general lease sale in offshore eastern Louisiana -- originally set for December 1971 -- was blocked by environmental groups which claimed that the Final Environmental Impact Statement of the Interior Department did not comply with the National Environmental Policy Act in failing to adequately discuss alternatives to the sale. A U.S. District Court granted an injunction barring the sale on this ground. After Interior filed a supplemental Environmental Impact Statement, the sale was finally held in September 1972. Another offshore Louisiana lease sale, encompassing over 600,000 acres of OCS lands, is presently scheduled for late December 1972.

The Bureau of Land Management is currently updating and revising the leasing schedule. Present plans call for two general sales of 300,000 - 600,000 acres each per year over a five-year period in the Gulf of

Mexico. Development of the acreage involved is estimated to require the drilling of 3,500 to 4,500 wells which, in turn, are estimated by Interior to result in an increase in crude oil reserves of 2.5 to 5.0 billion barrels and an increase in gas reserves of 20 to 40 trillion cubic feet. BLM also contemplates offering further leases in the Gulf of Mexico if no sales of OCS lands in the Gulf of Alaska and the Atlantic region are held by 1976. Sales of leases in these areas must be preceded by considerably more study of environmental and other factors.

Two major roadblocks could possibly delay or, in certain areas, actually prevent future OCS oil and gas leasing: (1) federal-state jurisdictional disputes, and (2) opposition by environmentalist and conservation groups.

Jurisdictional limits will be determined by future court cases, or statutues, since application of the terms of previous legal decisions to unsurveyed land-sea margins to define seaward boundaries is virtually impossible. As noted, the question of federal versus state jurisdiction in the Gulf of Alaska and Atlantic Coast offshore areas is currently in litigation. Either resolution of these conflicts, or negotiation of interim zone arrangements as in Louisiana, is necessary before major leasing actions can be undertaken.

Due to environmental considerations, leasing of OCS lands has already been delayed, and court suits to block further sales could cause additional delay. In California, moreover, there is presently a moratorium on all offshore leasing, the result of public reaction following the oil spill in the Santa Barbara Channel in January 1969. In April 1971, the Interior Department suspended further operations in 35 federal leases

in the Santa Barbara Channel until January 1973 to permit Congress to consider a pending bill for termination of the leases and for establishment of a national energy reserve. This suspension order was reversed by a U.S. District Court in California (as to 11 leases of four companies which challenged the action) and is now on appeal to the U.S. Court of Appeals for the Ninth Circuit in San Francisco. (Gulf Oil Corp. et al. v. Rogers C. B. Morton, No. 72-2449)

Finally, in Atlantic Coast offshore areas, any leasing of OCS lands faces considerable opposition from the adjacent states.[1/] Several bills sponsored by Senators or Representatives of Eastern Seaboard states were introduced in the last session of Congress to bar any federal sale of leases for at least two or three years pending thorough study of all environmental factors and/or adoption of a program of marine sanctuaries. The Interior Department is going forward with collection of information regarding the oil and gas potential of the Atlantic Outer Continental Shelf area and the environmental implications of lease sales in this area, but Secretary Morton has indicated that any decision to lease and permit exploratory drilling is still a few years in the future.[2/]

1/ For example, a special commission on marine boundaries and resources of the Massachusetts Legislature recently issued a report recommending against any Atlantic OCS development until (a) the present oil import quota system had been abolished, (b) national policies respecting energy and marine resources had been developed, and (c) spill prevention technology and oil spill cleanup techniques had been considerably improved. The report followed hearings on the possible development of oil and gas in the George's Bank region off Massachusetts.

2/ Statement of Secretary of the Interior Rogers C. B. Morton, November 11, 1971.

2. Office of Coal Research

The Office of Coal Research administers the Federal Government's coal gasification program. This program was accelerated during the latter half of 1971 following President Nixon's Clean Energy Message of June 4, 1971 calling for expedited development of coal gasification technology. Subsequently, OCR signed an agreement with the American Gas Association providing for joint government-industry funding of expanded research efforts to produce pipeline-quality synthetic gas from coal. The agreement contemplates joint funding of $30 million annually over a four-year period, two-thirds to be provided by the Federal Government and one-third by industry.

The current OCR gasification program includes four ongoing pilot plant projects based on: (a) the HYGAS process (hydrogasification of bituminous coal) -- undergoing testing by the Institute of Gas Technology at a pilot plant in Chicago; (b) the CO_2 Acceptor Process -- undergoing testing by Consolidation Coal Co. at a lignite gasification pilot plant recently completed at Rapid City, South Dakota; (c) the BIGAS process -- to be tested by Bituminous Coal Research, Inc. at a pilot plant under construction near Homer City, Pennsylvania; and (d) the SYNTHANE process developed by the Bureau of Mines -- to be tested at a pilot plant scheduled to begin construction in the fall of 1972 near Pittsburgh, Pennsylvania.

The pilot plant program is intended to aid the design of a demonstration plant to be built, largely through industry financing, within five or six years. It is hoped that operation of the demonstration plant will provide, by the end of the decade, a sound commercial basis for the construction and operation of large coal-based synthetic pipeline gas plants. OCR's target date for coal gasification on a commercial scale is 1980.

C. Federal Power Commission[1/]

The Federal Power Commission has extensive power to regulate the transportation and sale for resale of natural gas in interstate commerce. These powers stem from the Natural Gas Act, passed in 1938 but considerably broadened in scope by the Supreme Court in 1954 in Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672.

1. Background of the Natural Gas Act

Passage of the Natural Gas Act was the result in large part of pressures arising from diminishing production in the Appalachian area after 1917 and the inability of particular states to control sharply increased prices of gas imported from other states. In 1928, the Senate adopted a Resolution directing the Federal Trade Commission to investigate public utility corporations doing an interstate business in electricity and gas, as well as the activities of holding companies controlling such corporations, and to make reports and recommend legislation necessary to correct any practices tending to create a monopoly or other abuses. In 1935, the FTC issued a report emphasizing, among other things, problems created by the unregulated control of pipeline transmission, the concentration of control of interstate pipelines in a few holding companies, and the need for conservation of gas. A principal conclusion of the report was that the business of transporting and selling natural gas for ultimate distribution to the public was a matter affected with the public interest

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1/ Because of the critical impact which the FPC has had and will continue to have on gas supply, its activities and policies to date are described in a separate chapter, which follows.

and should be subjected to federal regulation. It was largely on the basis of the FTC report that Congress led to pass the Natural Gas Act three years later.

At the time of enactment, the Natural Gas Act was widely thought to apply only to interstate pipelines. The legislative history gives no indication of any intent that it also cover independent producers. This interpretation was also believed to flow from Section 1(b) which specifically provides that the Act not apply to the "production or gathering of gas."[1/]

The Section 1(b) proviso, however, proved to be ambiguous and the source of considerable controversy over the following decade and a half. In essence, the advocates of greater regulation contended that regulation of sales by pipelines was ineffective without regulation of sales to pipelines by producers. During this period, the FPC consistently declined to assume jurisdiction over sales by producers (except producers affiliated with interstate pipelines).

In 1951, following an investigation to determine whether Phillips Petroleum Co. was a natural gas company subject to its jurisdiction, the FPC reaffirmed its position that producer sales were so closely related to "production and gathering" as to be exempt from Federal regulation. This

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1/ Section 1(b) of the Natural Gas Act reads as follows:

> "The provisions of this act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas." [52 Stat. 821 (1938); 15 U.S.C. Section 717(b)]

decision was reversed by the U.S. Court of Appeals for the District of Columbia Circuit which, in 1954, was upheld by the Supreme Court. A majority of the Supreme Court interpreted the Section 1(b) proviso exempting production and gathering to mean "'physical activities, facilities and properties used in the production and gathering of gas,'" but not to sales after production and gathering. Rather, the Court concluded that "'the legislative history indicates a congressional intent to give the Commission jurisdiction over the rates of all wholesale of natural gas in interstate commerce, whether by a pipeline company or not and whether occurring before, during, or after transmission by an interstate pipeline company.'" (347 U.S. at 682)

Thus, FPC jurisdiction over wellhead sales by independent pro-producers for resale in interstate commerce was established by the Supreme Court. Various legislative efforts were made in the next few years to remove this jurisdiction or to lessen the extent of the FPC's authority over independent producers, but none were successful.[1/]

2. Scope of FPC Powers Under Natural Gas Act

Pursuant to various sections of the Act, the FPC exercises rate, certificate and abandonment authority over sales, transportation and facilities constructed by natural gas companies for such purposes. The FPC also has jurisdiction over gas imports and exports, as well as broad

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1/ For example, one bill (the Harris Fulbright bill) was passed by Congress in 1956 but vetoed by President Eisenhower because of disclosure of a campaign contribution by a registered lobbyist for an oil company. Another amendatory bill (the Harris-O'Hara bill) was introduced in the following Congress but was dropped after a further campaign contribution episode.

power to issue rules considered necessary to carry out the functions under the Act.

As noted, the FPC's jurisdiction is limited to transportation in interstate commerce and sales for resale in interstate commerce. Section 1(b) of the Act specifically excludes any other transportation or sale, as well as the "local distribution" of gas and related facilities. Further, Section 1(c) -- added to the Act in 1954 -- exempts essentially local companies receiving gas from an interstate source, provided (a) the sale takes place within or at the boundary of the state; (b) all of the gas is ultimately consumed within the state; and (c) a state commission certifies to the FPC that it is exercising regulatory jurisdiction over the rates, services and facilities of the company involved.[1/]

Rate authority is exercised under Sections 4 and 5 of the Act. Section 4 requires that rates and charges for the transportation or sale of jurisdictional gas shall be "just and reasonable" and not unduly discriminatory. Any increase (or other change) in rates must be filed with the FPC at least 30 days in advance of the proposed effective date. The FPC may allow the increase without formal hearing; or it may hold a hearing and, pending decision, suspend the increase for a maximum of five months --

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1/ Section 1(c) is known as the Hinshaw Amendment. It was passed to counteract initial efforts by the FPC -- notwithstanding Section 1(b) -- to exercise jurisdiction over companies which received gas from interstate pipelines for subsequent transportation and/or distribution wholly within one state. The FPC was affirmed in its position by the Supreme Court in 1950. Regarding this as too broad an intrusion into state regulatory authority, Congress amended the Act in 1954. Thus far, some 180 companies have applied for and been granted an exemption under the Hinshaw Amendment.

after which the change may go into effect subject to refund of any portion of the increased rate ultimately found not just and reasonable. Section 5 gives the FPC power to institute an investigation into the rates and charges of a jurisdictional natural gas company -- either on its own motion or on complaint by another party -- and to prescribe just and reasonable rates to be collected prospectively by such company.

Certificate authority is exercised under Section 7(c) of the Act which requires that natural gas companies obtain certificates of "public convenience and necessity" to transport and sell natural gas, and to construct, extend or acquire facilities for such purposes. The FPC may attach conditions to the issuance of such certificates, and it may issue temporary certificates in cases of emergency (again with conditions) without notice or hearing.

Under Section 7(a), the Commission also has power to direct natural gas companies subject to its jurisdiction to interconnect with and sell gas to municipalities and others engaged in distribution of gas for public consumption, provided such interconnection and sale will not impair the company's ability to render adequate service to its customers.

Abandonment authority is exercised under Section 7(b) which provides that jurisdictional facilities and service may not be abandoned without a finding by the Commission "that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment."

Exportation and importation of gas must be authorized by the FPC under Section 3 of the Act.[1/] The statutory standard is that authority shall be granted unless the Commission finds that the proposed exportation or importation "will not be consistent with the public interest." The Commission may grant authority with conditions. It may also, ". . . from time to time and . . . for good cause shown, make such supplemental order in the premises as it may find necessary to appropriate." (In effect, this provision gives the FPC power to modify the terms of any import authority at any time in the future.)

Section 16 of the Act grants the FPC broad rulemaking authority. Under this Section, the Commission may "perform any and all acts" and "prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this act." Procedurally, before adopting a new rule or regulation under Section 16, the FPC must publish notice of the proposal and provide an opportunity for comment by interested persons. However, no hearings are required (although they may be held). Further, while the FPC must state reasons for any rulemaking action, it need not amass and analyze voluminous evidence in support of its action. In this way, rulemaking differs importantly from contested rate and certificate proceedings

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1/ Pursuant to Executive Order No. 10485, issued September 8, 1953, the FPC is also required to issue permits for the construction and operation of border facilities for the exportation and importation of natural gas to or from a foreign country. Before issuing such permits, the FPC must obtain favorable recommendations from the Secretaries of State and Defense.

(wherein the Commission must hold hearings before reaching a decision) and hence affords a vehicle for the Commission to implement new regulatory policies in a relatively expeditious manner. In recent years, the FPC has used its rulemaking authority to an increasing degree to promulgate major policy changes.

D. Other Federal Bodies

1. Departments of State, Defense and Commerce

The Departments of State and Defense both have an important voice in policy matters affecting the supply of petroleum in the United States. In the past, the activities of the two Departments have been directed largely to oil. However, in light of the probability of increasing imports of gas (and/or liquids as feedstock for the manufacture of gas), the degree of interfuel substitutability possible in many markets and the need for a coordinated interfuel approach to current energy questions, both State and Defense seem likely to become increasingly involved in formulation of policies affecting the supply of gas in the future.

To date, the State and Defense Departments have been consistently asked by the FPC for their position concerning both pipeline imports from Canada and, more recently, LNG imports from Algeria and Libya.[1/] There has been no opposition by the State Department to any announced gas import

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1/ Under Executive Order No. 10485, the FPC is required to obtain the favorable recommendations of the Departments of State and Defense for the construction and operation of border facilities for the exportation and importation of gas.

project thus far. Nor has the Defense Department recommended denial of any gas import project, although it has expressed concern in some instances that individual pipelines and gas distribution companies not become overly dependent on imported LNG.

Similarly, the Commerce Department has not played a significant role in policies affecting gas supply in past years. However, during 1972, it participated in trade negotiations with the Soviet Union involving, among other things, the possibility of joint ventures to bring Soviet gas in liquefied form to the U.S. by the end of this decade. But the Secretary of Commerce recently advised that an early agreement concerning any such venture was not imminent.[1/] In any event, even if some form of tentative agreement were signed in the near future, the importation of Soviet LNG faces so many policy and regulatory considerations as to render it a highly speculative source of supply at this time.

2. Price Commission

The Price Commission was established under Executive Order No. 11627 of October 15, 1971 and is composed of seven public members appointed by the President on October 22, 1971. The Price Commission was directed to prescribe specific standards, criteria and regulations to carry out the goals of the Cost of Living Council to stabilize prices and rents.

1/ Speech of Peter G. Peterson, Secretary of Commerce, before the American Petroleum Institute in Chicago, November 14, 1972.

Sales of gas subject to regulation -- including wellhead sales under FPC jurisdiction -- are governed by Price Commission rules issued for regulated public utilities. These rules have undergone several revisions over the past year with respect to requirements for notifying the Price Commission of requested rate increases and those approved by regulatory agencies, provisions for further review by the Price Commission of agency-authorized increases, and guidelines applicable to utility increases. Since its inception, however, the Price Commission has generally accepted the rulings of state and federal commissions in regard to rate increases for regulated companies.

Initially, the Price Commission required federal and state regulatory agencies to review all price increases for consistency with the purposes of the Economic Stabilization Act and to certify all approved increases as consistent with such purpose. However, the Price Commission retained the power to further review -- and modify -- such increases within a specified period. Several criteria were later issued by the Price Commission for use by regulatory bodies in appraising permissible increases, including that the increase (a) is cost-justified and does not reflect future inflationary expectations; (b) is the minimum required to assure continued, adequate and safe service, or provide for necessary expansion to meet future requirements; (c) will achieve the minimum rate of return needed to attract capital at reasonable costs and avoid impairment of credit; (d) does not reflect labor costs in excess of those allowed under Price Commission policies; and (e) takes into account expected and obtainable productivity gains.

Effective March 20, 1972, the Price Commission provided for the issuance of Certificates of Compliance to regulatory agencies whose proposed procedures for dealing with utility rate increases were deemed satisfactory to the Price Commission. Agencies receiving such Certificates thereafter assume final responsibility for all approved increases, with the Price Commission reserving only the right to monitor their decisions. As of the end of October 1972, the Price Commission had issued Certificates of Compliance to 27 state commissions and 2 federal agencies (the Civil Aeronautics Board and the Interstate Commerce Commission).

The Federal Power Commission has not received a Certificate of Compliance from the Price Commission. However, to date, the Price Commission has not blocked any rate increase approved by the FPC for either pipeline companies or producers. With respect to each such approval, the FPC has certified that its actions are consistent with the economic goals of Administration's wage-price stabilization program and meet other requirements of Price Commission regulations. In one order (Order No. 437A-4, issued November 29, 1971) pertaining to increased rates allowed for producer sales in South Louisiana and three other areas, the FPC explained its position as follows:

> "This Commission has been confronted with conclusive evidence demonstrating a gas supply shortage. Every indication is that such a shortage will continue into the near future. The actions which we have taken in these recent opinions are designed to reverse this trend and to augment the Nation's dwindling gas reserves. To this extent the rates and other provisions in those determinations have used price as a tool to bring gas to the marketplace; in other words, to obtain for the public service the needed amount of gas. We have attempted to provide the proper economic climate to stimulate exploratory and developmental efforts in order to provide adequate service to the consumer at the lowest reasonable rate. An important policy consideration which we cannot

ignore is the substantial burden which would fall upon the consumer if higher priced alternative energy supplies are required to alleviate the gas shortage. It is imperative that adequate sources of energy, including natural gas, be available to sustain the Nation's economic growth. Thus, we have balanced our regulatory responsibilities under the Natural Gas Act with the President's economic goals, and find they are not inconsistent."

In sum, other than adding another tier of regulation, Price Commission controls have had little impact on the price of gas sold in interstate commerce for resale. However, with respect to intrastate gas sales which are not subject to FPC regulation, the Price Commission in several instances has denied rate increases because they exceeded base period prices or profit margins, or for certain other reasons. The result has been the diversion of considerable quantities of intrastate gas, particularly in Louisiana and Texas, to interstate sales under emergency procedures. As explained in Chapter IV (p. IV-25), the FPC has adopted measures in the past few years to permit emergency sales of gas to interstate pipelines for 60-day periods without certificate authorization and for periods exceeding 60 days under limited-term certificates. The purpose of these emergency procedures is to alleviate curtailment problems of pipelines which are unable to purchase sufficient supply to maintain existing delivery levels to their customers. The price level for limited-term emergency sales has been restricted by the FPC to about 35¢, but this is higher than contract prices for many intrastate sales. Thus, because the Price Commission has so far not interfered with prices of regulated sales, gas which might otherwise be committed to intrastate buyers is transferred to interstate purchasers on an emergency basis.

The present wage-price stabilization program is scheduled to expire on April 30, 1973. The Secretary of the Treasury recently indicated that the Administration will ask for an extension of controls beyond that date. Such extension must be approved by Congress.

3. Atomic Energy Commission

Through its Plowshare Program, the Atomic Energy Commission is responsible for research aimed at the development of peaceful nuclear explosives to improve utilization of natural resources, especially stimulation of production from natural gas fields. Much of this research is conducted jointly with industry.

Two jointly sponsored experiments involving underground nuclear explosives to stimulate gas production from tight formations have been conducted to date: (a) Project Gasbuggy with El Paso Natural Gas Co. in 1967; and (b) Project Rulison with Austral Oil Co. and CER Geonuclear Corp. in 1969.

Project Gasbuggy involved the firing of a 29 kiloton explosive on December 10, 1967, at a depth of 4,240 feet in the San Juan Basin of New Mexico. Project Rulison detonated a 43 kiloton explosive on September 10, 1969, at a depth of 8,426 feet in the Mesaverde formation, about six miles southeast of Grand Valley, Colorado. Both projects are now undergoing testing with respect to production capabilities and pressure buildup.

Two additional potential projects partly sponsored by AEC offer possibilities for extending gas stimulation technology. One -- Project Rio Blanco -- contemplates the simultaneous detonation of multiple explosives with an aggregate yield of about 90 Kt, spaced vertically at gas-bearing

depths between 5,000 and 7,000 feet, at a location in Rio Blanco County, Colorado, utilizing land rights obtained by the CER Geonuclear Corp. under a joint venture agreement with Equity Oil Co. The other project -- Wagon Wheel -- involves the sequential detonation of five nuclear explosives, each with a yield of about 100 Kt vertically spaced in the same well at depths between 9,000 and 12,000 feet, at a location in the Pinedale Field in Wyoming. Wagon Wheel would demonstrate the feasibility of sequential firing and its effects on fracturing, stimulation and chimney interactions at greater depths than previously attempted.

AEC is also currently engaged in studies directed toward developing a small diameter, minimum residual tritium, nuclear explosive called DIAMOND, for particular use in gas stimulation. The diameter factor is important because of limitations of drilling technology and drilling costs. The diameter of the DIAMOND explosive is less than the 8-inch diameter of the Rulison explosive and can therefore be emplaced in a 9-5/8-inch well casing. The DIAMOND design was successfully tested when a device called Miniata was test fired at the AEC's Nevada Test Site on July 8, 1971.

It is believed by some that very substantial gas reserves in the Rocky Mountain area can be "unlocked" from tight formations by underground nuclear explosions. However, the outlook for this supply of gas is quite uncertain. While AEC has announced its intent to pursue the Plowshare Program, future scheduling has been placed in abeyance pending study of environmentalist protestations as well as the results of the first tests (e.g., the level of radioactivity in the gas reserve).

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CHAPTER IV - FEDERAL POWER COMMISSION REGULATION OF NATURAL GAS

Regulation by the Federal Power Commission has clearly been a dominant factor affecting the supply of natural gas for the past 15 years. This is not to say, however, that other factors have not also had an important influence on industry motivation to explore for and produce gas. Some of the more important include federal taxation of oil and gas, the oil import program, and the availability of alternative outlets for capital investment by U.S. companies both at home and abroad.

This chapter seeks to review highlights of FPC regulation pertinent to an understanding of the present supply situation. Before proceeding with this review a brief chronology of the major events of FPC regulation is set forth below.

1928 - FTC directed by Senate to investigate public utility corporations engaging in interstate electric and gas business

1935 - FTC recommends federal regulation of transportation and sales of gas in interstate commerce

1938 - Natural Gas Act passed, giving FPC authority over transportation and sales of gas for resale in interstate commerce

1954 - Supreme Court holds Natural Gas Act applies to wellhead sales by producers for resale in interstate commerce

1960 - FPC adopts area rate approach for producer sales

1965 - FPC issues first area rate decision (Opinion No. 468 for Permian Basin area)

1968 (May) - Supreme Court affirms FPC Opinion No. 468

1968 (September) - FPC issues second area rate decision (Opinion No. 546 for South Louisiana area)

1970 - U.S. Court of Appeals upholds FPC Opinion No. 546, but with invitation for upward price adjustments

1971 (April) - FPC orders interstate pipelines to file curtailment of service plans

1971 (July) - FPC issues second decision in South Louisiana area decision, approving higher rates (Opinion No. 598)

1972 (June) - Supreme Court upholds FPC authority to control curtailments of service by interstate pipelines to all customers

1972 (June) - FPC authorizes first base load importation of LNG from Algeria over long term

A. Producer Sales at the Wellhead

Without question, the most difficult and controversial aspect of FPC regulation has been its regulation of producer sales of natural gas at the wellhead. Various regulatory methods have been attempted -- based for the most part on cost computations for individual producers or for groups of producers in particular producing areas of the nation. In terms of eliciting supply sufficient to meet demand, these attempts must be pronounced a failure. For well over a decade, the FPC virtually froze the price of gas at levels fixed according to criteria bearing little or no relationship to marketplace realities. The effect was twofold: to discourage investment by producers in gas exploration and production, while at the same time (through low prices for gas) artifically inflating the demand for gas in relation to other fossil fuels.

The history of area rate regulation, coupled with the history of certification of new gas at so-called "in-line" and "guideline" rates, is complex but crucial to an appreciation of the present gas supply picture and the

current pressures for amendment of the Natural Gas Act to remove or relax FPC control over producer prices.

Producer rate regulation may conveniently be described in three periods: 1954 through 1960, 1961 through 1968, and 1969 to date.

1. 1954 Through 1960

Upon issuance of the Supreme Court's decision in the Phillips case in 1954, the FPC was suddenly faced with the unwanted task of regulating literally thousands of producers. It was soon deluged with a flood of rate filings under Section 4 and applications for certificates to initiate (or continue) sales under Section 7. The first six years of its regulation -- ending with the adoption of an area approach to producer rates -- proved to be an administrative chaos, as the Commission struggled to handle matters on an individual company basis and fell farther and farther behind in coping with a continually rising backlog.[1/] The 1954-1960 period was also characterized by court reversal of higher rates approved by the Commission for new gas sales. These rates reflected at least in part a rapid growth in demand for gas as interstate pipelines expanded their systems to many unserved parts of the country and to provide additional gas to existing markets.

With respect to the certification of producer sales in this early period, the Commission -- except in rare instances -- approved the prices contained in the contracts. This practice, however, came to an end in 1959 with the Supreme Court's decision in the CATCO case. The CATCO case

1/ In 1960, the FPC was described as the "outstanding example in the Federal Government of the breakdown of the administrative process." Landis, Report on Regulatory Agencies to the President-Elect, printed for use of the Senate Committee on the Judiciary, 86th Congress, Second Session, 54.

involved large volumes sales by a group of four producing companies[1/] in South Louisiana at a proposed initial rate of 21.4¢ (plus 1¢ tax where applicable). This price was the highest ever negotiated at the time the contract was signed in 1956. The FPC twice refused to certificate the sale at the contract price (imposing various conditions instead) but, faced with the threat of contract cancellation by the producers and dedication of the gas to intrastate markets, backed down and approved the sale as proposed. The Supreme Court reversed,[2/] holding that the Commission was obligated to attach conditions to prices deemed "out-of-line" or otherwise not in the public interest. The Court said:

> "[The] inordinate delay presently existing in the processing of Section 5 proceedings requires a most careful scrutiny and responsible reaction to initial price proposals of producers under Section 7 . . . . The fact that prices have leaped from one plateau to the higher levels of another . . . [makes] price a consideration of prime importance . . . . Where the proposed price is not in keeping with the public interest because it is out of line or because its approval might result in a triggering of general price rises or an increase in the applicant's existing rates by reason of 'favored nation' clauses or otherwise . . . the Commission in the exercise of its discretion might attach such conditions as it believes necessary." (360 U.S. at 391)

Subsequent to the Supreme Court's decision in CATCO, several other FPC certificate orders approving contract rates for South Louisiana sales at rates equal to or higher than the CATCO level were set aside and remanded

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1/ The initials of the four companies -- Cities Service Co., Atlantic Refining Co. (now Atlantic Richfield), Tidewater Oil Co. (now Getty Oil Co.), and Continental Oil Co. -- account for the term "CATCO."

2/ Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378.

by four different U.S. Courts of Appeal on the ground that the prices in question were "out-of-line."[1/]

As to rate regulation under Sections 4 and 5, the FPC approached the problem of determining just and reasonable rates in the initial years by looking to the cost of service of each individual producer, the same approach followed for natural gas pipelines and electric utilities. Generally, the FPC's procedure was to consolidate into company-wide proceedings all of a company's rate increase applications together with investigations instituted under Section 5 into all of the company's rates. These proceedings proved to be exceedingly complex and time consuming, primarily because of difficulties in attempting to adapt the cost of service method to regulation of producers. The Commission's backlog of rate increase cases mounted rapidly. By 1960, only 11 such cases had been decided after full hearings, while 3,278 producer rate increase filings involving 570 companies were awaiting hearing and decision. (24 FPC at 545)

On September 28, 1960, in its first decision in a major company-wide rate proceeding (the original Phillips case which led to the Supreme

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1/ United Gas Improvement Co. v. FPC, 283 F.2d 817 (CA 9), certiorari denied sub nom. California Co. v. United Gas Improvement Co., 365 U.S. 881, and Superior Oil Co. v. United Gas Improvement Co., 365 U.S. 879; Public Service Commission v. FPC, 287 F.2d 146 (CADC), certiorari denied sub nom. Hope Natural Gas Co. v. Public Service Commission, 365 U.S. 880, and Shell Oil Co. v. Public Service Commission, 365 U.S. 882; United Gas Improvement Co. v. FPC, 287 F.2d 159 (CA 10); United Gas Improvement Co. v. FPC, 290 F.2d 135 (CA 5), certiorari denied sub nom. Sun Oil Co. v. United Gas Improvement Co., 368 U.S. 823 (October 9, 1961); United Gas Improvement Co. v. FPC, 290 F.2d 147 (CA 5), certiorari denied sub nom. Superior Oil Co. v. United Gas Improvement Co., 366 U.S. 965.

Court's 1954 decision holding the Natural Gas Act to apply to sales by producers for resale in interstate commerce), the FPC concluded, on the basis of its experience to that time, "that the traditional original cost, prudent investment rate base method of regulating utilities is not a sensible or even a workable method of fixing the rates of independent producers of natural gas."[1/] In support of this conclusion, the Commission pointed out that producers, for whom the results of exploration are highly uncertain, are not like public utilities which have a reasonably predictable relationship between investment and output. Further, the Commission reasoned, the necessity of allocating joint costs, i.e., costs incurred in producing oil and gas jointly (which typically account for about two-thirds or more of all costs incurred by producers), between gas and oil greatly complicates the costing process and can lead to widely divergent results, depending on the allocation methods used. Moreover, when an unrealistic result is reached, then the allocation formulae must be changed in order to bring about a reasonable result. The Commission also stressed the administrative impossibility of making separate cost of service determinations for each of the producers under its jurisdiction. Faced with a huge and ever-growing backlog of cases, the FPC predicted that it would be unable to become current in its producer rate work until the year 2043 even if its Staff of some 800 employees were tripled.

For these and other reasons, the FPC declared its intention to henceforth determine producer rates for the industry on an area basis. ". . .[I]t appears that the ultimate solution to producer regulation will

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1/ FPC Opinion No. 338, issued September 28, 1960 in re Phillips Petroleum Co. (G-1148 et al.); 24 FPC 537, 542.

be in the determination of fair prices for gas, based on reasonable financial requirements of the industry and not on the particular rate base and expenses of each company." (24 FPC at 547)

Simultaneously with its decision in the Phillips case, the FPC issued Statement of General Policy No. 61-1 establishing two sets of guideline prices for 23 different producing areas -- one set applicable to initial prices for certificating new sales and the other applicable to increased rates for existing sales. The Commission stressed that the guidelines did not constitute determinations of just and reasonable rates but rather were intended to facilitate producer regulation during the interim pending the completion of area rate proceedings. The specific guidelines were said to be based on all "relevant facts available" (including cost information from decided and pending cases, historical and existing price structures, area price trends over a number of years, production and exploratory trends, trends in demand, and others), but the weight given to any of these factors was not explained.

Nevertheless, an obvious objective of the Commission in Statement of General Policy No. 61-1 was to "hold the line" on producer prices then in effect. As shown by Table IV-1 on the following page, the initial guideline levels established by the Commission were below the highest rates at which gas was then being committed to the interstate market except in two areas (one a single field in Oklahoma). Moreover, in some areas, the initial guideline rates were well below previously authorized sales. The guideline levels for rate increase purposes were still lower than the initial rate guidelines in nearly all areas.

AREA GUIDELINE PRICES ESTABLISHED BY
STATEMENT OF GENERAL POLICY NO. 61-1

Issued September 28, 1960*

Area	FPC Increased Rate Level a/	FPC Initial Rate Level	Highest Price Filed
	(Cents per Mcf)		
Texas			
District #1 - South Central Texas	14.0	15.0	20.00
District #2) Texas Gulf Coast	14.0	18.0	22.00
District #3)	14.0	18.0	20.00
District #4)	14.0	18.0	20.00
District #5) Northeast Texas	14.0	14.0	--
District #6)	14.0	15.0	17.00
District #7B) West Texas	11.0	14.0	15.50
District #7C)	11.0	16.0	16.00
District #8)	11.0	16.0	21.80
District #9 - North Central Texas	14.0	14.0	14.49
District #10 - Texas Panhandle	11.0	17.0	23.00
Louisiana			
Southern	14.0 (plus tax)	21.5 (plus tax) b/	24.8 (including tax)
Northern	14.0 (plus tax)	17.0 (plus tax)	20.2 (including tax)
Mississippi	14.0	21.5 b/	22.88
Oklahoma			
Panhandle Area	11.0	17.0	23.00
Other	11.0	15.0	20.50
Carter-Knox	11.0	16.8	16.80
Kansas	11.0	16.0	23.00
New Mexico			
Permian Basin	11.0	16.0	21.26
San Juan Basin	13.0	13.0	17.0
Colorado	13.0	15.0	16.4
Wyoming	13.0	15.384	17.5
West Virginia	25.0	28.0	29.7

a/ The increased rate guidelines in most areas were subsequently raised by 1.0¢ for contracts from which all price escalation provisions had been eliminated and by 0.6¢ for contracts from which indefinite escalation provisions had been eliminated and definite escalation provisions had been modified to not more than 1¢ each five years. (Second and Seventh Amendments to the Policy Statement.)

b/ The 21.5¢ initial guidelines for South Louisiana and Mississippi were established by the First Amendment to the Policy Statement on October 25, 1960. Respecting South Louisiana, the guideline came to 23.8¢ including the tax level at that time (2.3¢). A year later, on October 31, 1961, the FPC reduced the initial guideline for South Louisiana to 21.25¢ (including tax) for sales within state taxing jurisdiction and 19.5¢ for sales outside state taxing jurisdiction. (Fourth Amendment to Policy Statement.)

* Prices stated at 14.65 psia in Texas, Oklahoma and Permian Basin of New Mexico; at 15.025 psia in Louisiana, Mississippi, Colorado, Wyoming and San Juan Basin of New Mexico; and at 15.325 psia in West Virginia.

The guideline levels were amended several times over the next five years -- mostly downward. Also, many of the areas set forth in the Policy Statement (reflecting in some instances, as in the State of Texas, merely administrative subdivisions) were later adjusted and combined for area rate proceeding purposes.

2. 1961 Through 1968

The next broad period of FPC regulation extends from the initiation in December 1960 of the first area rate proceeding -- the Permian Basin Area Rate Proceeding -- through late 1968. During this period the FPC completed two major area cases, establishing rates for the Permian Basin area only slightly higher than the guidelines fixed at the beginning of the decade and establishing rates for the South Louisiana area lower than the 1960 guidelines. The FPC decision in the Permian Basin case was upheld by the Supreme Court in 1968. The 1961-1968 period, particularly the earlier years, was also dominated by a series of certificate proceedings in which the Commission established "in-line" prices at or below the guideline initial price levels promulgated in 1960 and generally froze all new producer sales to those levels. The FPC's "in-line" policy developed as a result of the Supreme Court's CATCO decision and subsequent court decisions reversing and remanding FPC certificate orders because the prices were "out-of-line."

a. "In-Line" Regulation

During the first half of the 1960's, the Commission conducted numerous certificate proceedings to determine the maximum price at which

it would issue permanent certificates for new gas sales. The majority of these proceedings involved sales in the South Louisiana and Texas Gulf Coast areas, both major sources of gas supply for interstate pipelines. Some of the earlier South Louisiana proceedings included sales which had been remanded by the courts. The later cases primarily dealt with the large numbers of sales which had commenced under temporary certificates -- generally issued at guideline prices in the case of sales executed after September 28, 1960 (the date of the Statement of General Policy No. 61-1), although often with some type of refund condition[1/] -- pending hearings and grant of permanent certificates. In the Texas Gulf Coast cases, the Commission severed its consideration of pre-Policy Statement sales and post-Policy Statement sales in some instances.

The method generally applied by the FPC in these proceedings was to examine the prices at which sales in the area had previously been certificated, excluding "suspect" prices (those under certificates which had been set aside by the courts or were under court review, and all "like" prices), and then to select the "in-line" price level from the remaining sales. The effect of this technique was to substantially narrow the range of prices to be considered, since nearly all certifi-

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1/ The FPC's policy regarding the issuance of temporary certificates -- which permit producers to begin sales on a temporary basis pending a determination of whether permanent authorization should be granted on the terms proposed -- underwent several changes of direction during the early 1960's and must be characterized as indecisive at best. Some temporaries were issued with no conditions, others were conditioned to require refund of amounts collected in excess of the ultimately determined initial rate (but not below a certain floor level), and still others were conditioned to require refund of all excess amounts collected above the ultimately approved initial rate with no floor.

cates issued at prices higher than the guidelines (and, in some cases, at prices at or below the guidelines) were subject to litigation. As to the remaining sales, the process of selecting an "in-line" price was imprecise; considerable controversy developed over what sales should or should not be considered and over the weight to be accorded to those given consideration.

Using the above procedure, the Commission first determined in January 1962 an "in-line" price of 20.0¢ (including tax) for South Louisiana sales subject to state taxing jurisdiction and 18.5¢ for offshore Louisiana sales in the Federal Domain.[1/] This determination pertained to the original CATCO contracts executed in 1956. The same "in-line" prices were confirmed by the FPC in two subsequent decisions relating to later contracts.[2/] At the same time, a large number of South Louisiana sales were severed from the contested proceedings and granted certificates pursuant to settlement agreements providing for prices of 20.625¢ for sales within Louisiana taxing jurisdiction and 19.0¢ for offshore sales in the Federal Domain. In return for these somewhat higher price levels, the producers had to agree to file no rate increases (with certain exceptions) for a period of four to five years, to refund roughly two-thirds of revenues collected in excess of the settlement prices, and to extend the period to four years within

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1/ FPC Opinion No. 351, issued January 22, 1962 in re Continental Oil Co. et al. (G-11024 et al.); 27 FPC 96.

2/ FPC Opinion No. 398, issued July 17, 1963 in re Placid Oil Co. et al. (G-13183 et al.), 30 FPC 283; FPC Opinion No. 436, issued July 23, 1964 in re Union Texas Petroleum et al. (G-13221 et al.), 32 FPC 254.

which pipeline buyers could make up purchases that they had been obligated to pay for under contractual terms but could not physically take at the time.

In the Texas Gulf Coast certificate proceedings, the FPC determined "in-line" prices of 15.0¢, 16.0¢ and 17.0¢ depending on the date of contract and the particular subarea of the sales. However, in all subareas, the "in-line" determinations in the initial cases were below the applicable guideline levels which were accordingly lowered to the "in-line" levels (or, in one case, to a level 1¢ higher than the "in-line" price).

Virtually all of the FPC "in-line" price decisions were attacked on multiple grounds and appealed to the courts. The principal issues concerned the prices which the Commission should take into account in reaching its "in-line" determinations (including whether any weight should be given to guideline and temporary certificate prices), whether economic evidence on supply-demand and cost trends should be considered, whether the FPC had power to prohibit the producers from increasing rates above the levels which could trigger widespread increases in the areas involved; and the extent of the Commission's authority to order refunds of amounts collected above the in-line rates under both judicially invalidated certificates and temporary certificates. All of these questions eventually reached the Supreme Court, in part because of conflicting decisions by the courts below.

In two different decisions,[1/] the Supreme Court affirmed the FPC's approach in all significant respects. Specifically, the Court ruled

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1/ United Gas Improvement Co. v. Callery Properties, Inc., 382 U.S. 223 (1965); FPC v. Sunray DX Oil Co., 391 U.S. 9 (1968).

that the Commission correctly refused to hear economic trend and cost evidence in in-line proceedings because of the delays which consideration of such evidence would entail; that the imposition of moratoria on price increases above specified "triggering" levels was a justifiable measure to keep the general price level relatively constant pending determination of just and reasonable rates in area proceedings; that the FPC did not abuse its discretion in giving "some weight" to guideline and temporarily certificated prices; that the Commission could require refunds of revenues collected above the in-line rates pursuant to previously issued certificates which had been overturned by the courts; and, finally, that the Commission could order refunds of amounts collected in excess of in-line rates under temporary certificates which did not include an express refund condition.

The Court's holding on this last issue, namely, the ordering of refunds in the case of sales under temporary certificates which were granted without refund condition, is of particular interest in terms of its effect on producer expectations. The FPC had first ruled that it would be inequitable to require refunds in such situations because the temporaries contained no explicit language to warn the producers of the possibility of a refund and because the imposition of a refund condition retroactively would "so denature the value of a Commission authorization as to place any reliance on [its] actions in this area in serious jeopardy." (29 FPC 225). On appeal, the D.C. Circuit held that the FPC had power to order retroactive refunds and should undertake a "more penetrating" analysis of the equities involved. (PSC of New York v. FPC, 329 F.2d 242)

The FPC thereafter reversed its previous position and ordered refunds in several cases. Certain of these cases were appealed to the Tenth Circuit which agreed with the producers that the FPC did not have power to order refunds of amounts collected under unconditioned temporary certificates and that to require refunds retroactively would deny price assurance and undermine producer confidence. The Supreme Court rejected this reasoning.

> "When a producer has requested permission to begin delivery of gas prior to completion of normal certification procedures, due to an emergency, we think it not unfair that in return for that permission it accept the risk that at the termination of those procedures, the terms proposed by it may be retroactively altered to conform to the public interest." (391 U.S. at 50)

In sum, the overall effect of the FPC's "in-line" price policies developed during the early and mid-1960's was to freeze prices at pre-existing or lower levels.

b. Area Rate Proceedings

The second principal focus of FPC activity during the 1960's was the initiation and conduct of several area rate proceedings. The Commission chose the Permian Basin area of West Texas and Southeast New Mexico as the first producing region in which to test the area rate method. The Permian Basin proceeding was instituted on December 23, 1960. This was followed by the initiation of proceedings for the South Louisiana area on May 10, 1961, for the Hugoton-Anadarko and Texas Gulf Coast areas on November 27, 1963 (these two proceedings were conducted jointly for the most part during the hearing phase, although were decided separately), and for the Other Southwest area (consisting of Mississippi, Northern Louisiana, and parts of Oklahoma,

Texas, Kansas and Arkansas) on December 28, 1967. The first two area cases -- for the Permian Basin and South Louisiana areas -- dominated the scene and set the precedents.

The evidence introduced in the area rate hearings was voluminous and fell into two broad categories: economic (including industry structure, nature of the exploratory effort, supply and demand, pricing history, and financial requirements) and cost. The cost evidence related to composite industry costs computed both on a national and an area basis. The area cost data were collected via a questionnaire sent to all major producers in the area. The nationwide cost data were derived primarily from industry publications. The Commission outlawed cost evidence pertaining to operations of individual companies.

Hearings in the Permian Basin case began in October 1961 and lasted nearly two years. The total transcript comprised over 30,000 pages. On August 5, 1965, the FPC issued Opinion No. 468 deciding the case. (34 FPC 159) Opinion No. 468 adopted a two-price system of rates according to the contract vintage (and type) of gas. The contract dividing date was established at January 1, 1961. Thus, for "new" gas well gas sold under contracts dated since January 1, 1961, rates were fixed at 16.5¢ (including production taxes) in the Permian Basin area of Texas and at 15.5¢ (plus production taxes) in the Permian Basin area of New Mexico. For all other or "flowing" gas (i.e., gas well gas sold under contracts dated before January 1, 1961 and all casinghead gas), rates were fixed at 14.5¢ (including production taxes) and 13.5¢ (plus production taxes) in the Texas and New Mexico portions of the Permian Basin area, respectively.

The rationale for the two-price system was that a higher price based on current costs was needed to encourage producers to engage in further exploration and development directed specifically toward gas, while such a price for "flowing" gas discovered and developed in the past primarily in the course of searching for oil would only result in windfall profits. In addition, the FPC ordered refunds in full of all amounts collected under refund obligation (in Section 4(e) proceedings) in excess of area rates; imposed a moratorium or ban on rate increase filings above the area ceilings for about 2-1/2 years (until January 1, 1968); prescribed various pipeline quality standards and price adjustments for sales not meeting these standards; and established a procedure (although failed to spell out the qualifying circumstances) whereby producers could seek relief from area rates or refund requirements.

The FPC's Permian Basin decision, which represented the culmination of mammoth efforts by the participants in the case and by the Commission itself, has been the subject of extensive analysis. To producers it was a grave disappointment. To some others as well, the procedures used to arrive at the results seemed as illogical as the individual company cost approach rejected by the Commission in 1960. Two aspects of the decision bear emphasis here. The first is that the so-called "new" gas ceiling of 16.5¢ was only a half-cent higher than the guideline price established in 1960 for initial sales. The second is that the area ceilings fixed for both "new" and "flowing" gas[1/] were based solely on

1/ The latter is frequently referred to as "old" gas.

average cost determinations. The Commission said: ". . . A composite cost determination is the bedrock on which a regulated price must be established." (34 FPC at 189-190) The "new" gas ceiling rested on a composite cost computation of 16.43¢ for nonassociated (or gas well) gas on a nationwide basis, including a 12% rate of return, while the "flowing" gas ceiling was derived from an average cost of service determination for area production of the larger producer respondents in the year 1960. The cost estimation techniques, for both "new" and "flowing" gas, involved numerous allocation procedures which were the subject of much controversy during the protracted hearings (and subsequent court review). Notwithstanding the many difficulties involved in attempting to implement are ratemaking, the FPC clearly did not succeed in the Permian case in freeing the decisional process from the costing complexities, and the divergence of results depending on allocation methods used, which it had condemned in Opinion No. 338 in the Phillips case.

Opinion No. 468 was reversed by the Tenth Circuit Court of Appeals which criticized the FPC's failure to ascertain whether composite revenues resulting from the decision would balance composite costs.[1/] In light of this failure, the ordering of refunds was held to violate the so-called "end result" test laid down by the Supreme Court in 1944 (FPC v. Hope Natural Gas Co.; 320 U.S. 591), namely, that regulated companies under the Natural Gas Act are entitled to recover prudent operating expenses and capital costs plus a return commensurate with risks and sufficient to maintain credit and attract capital. However, on further appeal, the Commission's

1/ Skelly Oil Co. v. FPC, 375 F.2d 6 (1967).

opinion in the Permian case was upheld by the Supreme Court in all respects.[1/] The Supreme Court concluded that the FPC decision did not violate any legal requirements and generally represented a permissible exercise of discretion. At the same time, the Supreme Court made clear that its affirmation was influenced by the fact that the Permian case was the first area rate proceeding and that it expected the FPC to deal with issues more precisely as the agency gained greater experience with area rate regulation.

The second area case initiated by the FPC -- the South Louisiana Area Rate Proceeding (AR61-2) -- was decided in Opinion 546 (40 FPC 530), issued on September 25, 1968 (about five months after the Supreme Court's affirmation of Opinion No. 468 in the Permian case). The time elapsed between the commencement of this case (in May 1961) and the Commission's decision was over seven years. Hearings spanned a 28-month period between August 1963 and November 1965, resulting in a transcript totalling over 34,000 pages. The evidence introduced during these hearings followed essentially the same lines as in the Permian case and included voluminous cost studies, generating seemingly endless controversy over cost allocation methods and other costing techniques, as well as over many suggested adjustments to these methods and techniques. Similarly, the Commission's decision essentially conformed to the format established in the earlier area case, although with some differences.

Opinion No. 546 established a three-price system for South Louisiana sales. Regarding sales subject to state taxing jurisdiction,

1/ Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

the ceilings were fixed at 18.5¢ for contracts dated prior to January 1, 1961; at 19.5¢ for contracts dated January 1, 1961 to September 30, 1968; and at 20¢ for contracts dated on or after October 1, 1968. For federal offshore gas, all prices were 1.5¢ less. In addition, as in Permian, the FPC directed refunds of all amounts collected in excess of the area rates, prescribed quality standards and provided procedures for seeking special relief from the area ceilings. The Commission also imposed an indefinite moratorium on all rate increase filings above the area ceilings, which were to apply "until such time as they may be changed by the Commission"; this prohibition went considerably beyond the 2.5-year moratorium ordered in the Permian Basin decision.

The FPC cited various aspects of Opinion No. 546 which were deemed to provide encouragement for exploration and development. Whatever the merits of the Commission's rationale on these points, clearly the most notable aspect of Opinion No. 546 from the standpoint of supply elicitation purposes was the fact that all of the prescribed area ceilings were lower than the guidelines established by the Commission in 1960. Moreover, with the exception of the most recent vintage of contracts, these ceilings were below even the in-line rates determined in certificate proceedings in the 1960's. Finally, the 18.5¢ (offshore) and 20¢ ceilings applicable to contracts dated after October 1, 1968 were exactly the same as the initial rate reached by the Commission in Opinion No. 351 for the CATCO contracts executed in 1956 (which initial rates now had to be reduced to 18.5¢).

The Commission was attacked by South Louisiana producers for failing to take greater account of supply considerations, including the

declining trends since 1958 in reserve-production and finding-production ratios for the South Louisiana area. In a decision issued March 20, 1969 on rehearing (Opinion No. 546-A; 41 FPC 378), the FPC modified somewhat the moratorium provisions for contracts dated after October 1, 1968 but essentially adhered to its earlier decision. However, at the same time, the Commission initiated a new proceeding (AR69-1) to determine whether higher ceiling rates should be prescribed for offshore sales contracted since October 1, 1968.

FPC Opinion No. 546 was ultimately upheld in 1970 by the Fifth Circuit Court of Appeals which, however, expressed "serious misgivings" particularly as to the adequacy of the Commission's findings respecting supply, demand and the impact of the prescribed rates.[1/] Further, although affirming the FPC, the Court suggested that the Commission might wish to modify its earlier decision. On rehearing a few months later, the Court reiterated this suggestion and clarified the Commission's power to make whatever adjustments it deemed necessary.

> "Under Section 19(b) of the Natural Gas Act, this Court has the broad remedial powers that inhere in a court of equity, and pursuant to our equitable powers, we make it part of the remedy in this case that the authority of the Commission to reopen any part of its orders, including those affecting revenues from gas already delivered, is left intact. The Commission can make retrospective as well as prospective adjustments in this case if it finds that it is in the public interest to do so." (444 F.2d 125)

1/ Austral Oil Co. et al. v. FPC, 428 F.2d 407 (1970).

3. 1969 to Date

By late 1968 and the first part of 1969, there were growing signs of a gas supply shortage. One of the first indications was a letter dated December 16, 1968 from the President of the American Gas Association to the Chairman of the FPC requesting the Commission to reexamine its area rate policies because of an impending shortage of gas and the inability of many distribution companies to obtain long-term commitments of additional gas supply from interstate pipelines. This letter was noteworthy because of the active role played by several distributor groups during the 1960's in seeking to prevent increased price levels for producers. A few months later, the American Gas Association announced an absolute drop in U.S. proved gas reserves in 1968 for the first time in the nearly two decades during which the Association had compiled statistics, together with the lowest level of new supply additions since 1954.[1/] Speeches of various FPC members commenced to note these trends and to describe the gas supply situation as "critical." An FPC Staff report, released in September 1969, referred to mounting evidence that the nation's gas supply "is diminishing to critical levels in relation to demand" and predicted "only a few years remain before demand will outrun supply" on the basis of then prevailing trends.[2/]

1/ Excluding Alaska, gas reserve additions in the U.S. have been even lower than in 1968 in each succeeding year, while total proven gas reserves have fallen by nearly 15% since their peak level of 289 trillion cubic feet at the end of 1967.

2/ A Staff Report on National Gas Supply and Demand, FPC Bureau of Natural Gas, September 1969, p1.

Thus, since 1968, the FPC's regulation of producers has increasingly shifted toward the adoption of remedial measures aimed at reversing the downward trends in gas supply and encouraging higher levels of exploration for gas.

Among other things, a number of actions have been taken by the Commission in the past three years to increase the level of area rates. Significantly, in the South Louisiana area, the FPC reopened the earlier proceeding in its entirety for reconsideration and, on July 16, 1971, issued Opinion No. 598 superseding Opinion No. 546 and establishing substantially higher rates. Opinion No. 598 accepted, with certain modifications, a Settlement Proposal supported by nearly all parties -- including producers, pipelines, distributors and the FPC Staff.[1/] Pursuant to the Settlement, the FPC approved a 26¢ ceiling rate for all so-called "new" gas sold under contracts dated since October 1, 1968 and a 22.375¢ ceiling rate (1¢ less in the case of offshore gas) for gas flowing under earlier contracts. Certain fixed escalations in these rates in 1973 or 1974 were also approved. In addition, Opinion No. 598 adopted two novel measures specifically intended to encourage the dedication of new gas supplies to interstate pipelines. One was a refund workoff procedure under which producers could discharge their refund obligations by a credit of 1¢ applied to each Mcf of new gas committed to interstate pipeline buyers in South Louisiana over roughly the following six years. The second was a provision for contingent escalations of flowing gas rates depending on the extent of

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1/ The few parties which opposed the Settlement Proposal appealed Opinion No. 598 to the courts. The Fifth Circuit has the case under review.

additional new gas reserves in the area (beyond those required to work off refund obligations) committed by the producing industry as a whole to interstate pipelines in the following six years. The escalations are 0.5¢ if 7.5 trillion cubic feet are committed, 1.0¢ if 11.25 trillion are committed, and 1.5¢ if 15.0 trillion are committed.

In the Texas Gulf Coast area, the FPC -- in Opinion No. 595, issued May 6, 1971 -- adopted a three-price system, allowing a "new" gas price of 24¢ for sales under contracts dated October 1, 1968 and prices up to 19.0¢ for sales under earlier contracts. The FPC also provided for refund workoff and contingent rate escalation procedures similar to those adopted for the South Louisiana area. In Opinion No. 595, the FPC stressed, among other things, the necessity of offering incentives to find and dedicate gas to the interstate market in view of the "present critical shortage of all forms of energy in the United States and the anticipated rapid growth of demand for gas in particular." (Mimeo, page 42). Also, while the Commission reviewed the cost evidence in some detail, it acknowledged the overly restrictive nature of its costing methodologies applied in previous area decisions and attempted to express each of the cost items in the Texas Gulf Coast case in terms of a range of results.

In other areas, the FPC (1) accepted a producer settlement proposal establishing rates up to 20.5¢ for "new" gas (contracts dated November 1, 1969 and later) and up to 19.0¢ for flowing gas in the Hugoton-Anadarko area, together with partial relief from refunds of overcollections in earlier periods (Opinion No. 586, issued September 18, 1970 in Docket Nos. AR64-1 et al.; 44 FPC 761); (2) established "new" gas ceiling rates

ranging up to 26.0¢ and "flowing" gas ceiling rates ranging up to 20.0¢ for sales in different subareas of the Other Southwest area, with most of the subarea ceilings materially exceeding the levels recommended by the Examiner in the case a few years earlier (Opinion No. 607, issued October 29, 1971 in Docket Nos. AR67-1 et al.; 46 FPC 900); (3) established new gas rates of 32.0¢ and 34.0¢ for sales in the Appalachian area (Order No. 411, issued October 2, 1970 in R-371; 44 FPC 1112);[1/] and (4) instituted new proceedings -- currently awaiting decision -- for the Permian Basin area (FPC order dated June 17, 1970 in Docket No. AR70-1; 43 FPC 899).

A number of other actions have also been taken by the FPC in an effort to provide greater funds for producers and to encourage dedication of new supplies to interstate markets. Several such measures have been promulgated under the Commission's rulemaking powers, thereby simplifying the procedural requirements and permitting more expeditious action. Some of the Commission's more significant rulemaking actions in recent years include: (1) exemption of sales by small producers (defined as companies with annual jurisdictional sales not over 10 billion cubic feet a year) from nearly all regulation under the Natural Gas Act (Order No. 428, issued March 18, 1971); (2) encouragement to pipeline companies to advance sums of money to producers to explore for and develop new gas supplies by permitting the inclusion of such advances in the pipelines' rate bases and the earning of a return thereon (Order No. 410, issued

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1/ A petition to raise these rates to 50¢ is now pending before the Commission.

October 2, 1970, amended by Order No. 441, issued November 10, 1971); and (3) adoption of a policy to suspend producer rate increases for one day only, rather than the full five-month statutory period permitted under the Natural Gas Act (Order No. 423, issued February 18, 1971).

In addition, the FPC has sought to relieve curtailment problems for individual pipelines[1/] by permitting the purchase of gas on an emergency basis at rates considerably above the area ceilings. Specifically, the Commission adopted rules to (1) permit emergency sales by independent producers for 60-day periods without certificate authorization (Order No. 418, issued December 10, 1970); and (2) to permit limited-term sales by producers for longer than 60 days, at rates above the area ceilings, to interstate pipelines demonstrating an emergency need for gas (Order No. 431, issued April 15, 1971).[2/]

Many of the above actions designed to stimulate increased supply have been appealed to the court, and their validity remains uncertain at this date. In one decided case involving the ratemaking treatment provided by the Commission for advance payments by pipelines to producers to develop additional gas, the U.S. Court of Appeals for the D.C. Circuit held that the

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1/ In 1970, the shortage of gas supply led two major interstate pipelines to seek FPC approval of procedures proposed for curtailing deliveries to their customers. In the following two years, eight pipelines have been forced to curtail firm sales -- by increasing amounts. These curtailments, and the FPC's response to the problem, are discussed at a later point in this Chapter.

2/ As of September 21, 1972, the FPC had issued 87 certificates for limited-term sales by producers -- mostly at rates of 35¢ -- representing a total dedication to interstate pipelines of nearly 600 billion cubic feet. (Speech of FPC Chairman John Nassikas to Independent Petroleum Association of America, October 18, 1972.)

FPC's action constituted a justifiable experiment in its search for solutions to alleviate the gas shortage.[1/] However, in a more recent decision, the same Court overturned the FPC's exemption of small producer sales from rate regulation, holding that such action constituted an abdication of the Commission's responsibility to insure that all rates of all natural gas companies are just and reasonable and hence was beyond the Commission's statutory power.[2/]

The most recent, and perhaps most far-reaching, measure taken by the FPC in response to the growing shortage of domestic gas supply was its adoption last summer of a new optional procedure for certificating new gas sales by producers at rates in excess of area ceilings (Order No. 455, issued August 3, 1972). The new procedure, which is subject to several restrictions as to its use, essentially contemplates a one-time review of new gas sales contracts in an effort to reduce uncertainty respecting future rates. The FPC action was immediately appealed to the courts as tantamount to deregulation, and the outcome of this litigation is undoubtedly a year or more in the future.

The optional certificate procedure established in FPC Order No. 455 is discussed further in Chapter V (pages V-43 through V-48).

B. Pipeline Rates

Pipeline rates have been determined by the FPC from the outset by the traditional utility rate base method which involves calculation of a total cost of service for a specified test period and translation of

1/ PSC of New York v. FPC, CADC, No. 71-1161, decided March 29, 1972, rehearing denied May 19, 1972.

2/ Texaco Inc. et al. v. FPC, CADC, Nos. 71-1560 et al., decided December 12, 1972. It is probable that the FPC may appeal this decision to the Supreme Court.

that cost of service into jurisdictional rates through various cost allocation and rate design techniques.

The costs to be recovered through rates include all operating and maintenance expenses, depreciation and depletion, and taxes, plus a fair rate of return on rate base. The rate base consists of investment at original cost (less accrued depreciation) plus an allowance for working capital. Determination of rate of return is governed by certain well-established criteria in public utility regulation, namely, a fair return is commensurate with returns on investment in other enterprises with corresponding risks, sufficient to attract capital and adequate to assure financial integrity.

Use of the cost of service approach for determining pipeline rates is widely accepted, although the computation of individual cost components and determination of the rate of return level are frequently heavily contested in pipeline rate proceedings. However, with one exception, these disputed costing matters generally have no bearing on whether more or less gas will be available and hence are beyond the supply focus of this study.[1/]

The one exception relates to gas produced by a pipeline itself or purchased by a pipeline from an affiliated producing company. The pricing of such gas has had a long history in the FPC and in the courts. In 1954, the Commission granted Panhandle Eastern Pipe Line Co. a commodity value allowance (essentially, the average field price of comparable gas

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1/ It may be noted, however, that in recent years, several pipelines have sought higher depreciation rates for plant and other investment because of declining gas supply. This situation, the pipelines allege, results in reducing the number of years existing facilities can be expected to remain in use, thereby requiring a higher rate of annual depreciation in order to recover investment. One pipeline, for example, recently requested an increase in depreciation rate from 4% (implying an average plant investment life of 25 years) to 8.33% (implying an average life of 12 years). The pipeline claims the 8.33% rate is justified by an expected 12-year period of deliverability from its dedicated recoverable gas reserves.

sold in the same producing areas) for its own gas production. This decision, however, was overturned in 1956 by the Court of Appeals for the District of Columbia Circuit which ruled that the FPC was required to apply the cost of service rate base approach to pipeline-produced gas at least as a point of departure and to show any allowance higher than a cost-based amount to be no more than needed to encourage pipeline exploration and development of its own production.[1/] As a result of this court opinion, the FPC -- up until the last few years -- followed the traditional cost of service approach for pipeline-produced (and affiliate-produced) gas, i.e., it permitted pipelines to include in their cost of service an allowance no greater than the estimated costs of producing that gas. For most pipelines, such allowances were considerably lower than the prices paid to independent producers for gas purchases in the same producing areas.

In 1966 the FPC initiated a proceeding to determine the proper method to be used for pricing gas produced by pipeline companies and/or obtained from affiliated producers. The first phase of the proceeding was directed to the pricing of such gas in the future, specifically, gas produced from leases acquired after the date of an FPC decision. Evidence submitted in the proceeding indicated, among other things, that reserves owned by pipelines engaged in production operations declined both absolutely (by close to 30% between the period 1958-1966) and as a proportion of national gas reserves (from 25% to 13%). On October 7, 1969, the FPC

1/ City of Detroit v. FPC, 230 F. 2d 810 (1955); certiorari denied, 352 U.S. 829 (1956).

decided that gas produced by pipelines from leases acquired thereafter could be reflected in pipeline rates at the area price levels allowed independent producers for comparable gas.[1/] This change to an area method, the FPC made clear, was intended to encourage pipelines to increase their search for and production of gas.

The FPC was judicially affirmed in this new ratemaking approach to pipeline-produced gas. Thus far, however, the approach has not resulted in any increase in pipeline production. In part, insufficient time has elapsed for a fair appraisal, considering the lead time needed to lease, explore and develop gas reserves before production can commence. Probably a more important reason, however, is that current area rates do not provide sufficient incentive for either independent producers or pipeline producers to step up their search for and production of gas.

Once a pipeline's cost of service has been established, the next steps in the rate fixing process are allocation of that cost of service to different classes of service and rate design. Here, the methods applied by the FPC over the years have played a role in the overall background leading to the gas demand-supply picture today.

In general, most pipeline companies sell the major portion of their gas under firm rates to distributors for resale to residential, commercial and industrial consumers and the remainder as direct sales to industrial customers (including power plants) under firm or interruptible

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1/ FPC Opinion No. 586, issued October 7, 1969 in re Pipeline Production Area Rate Proceeding (RP66-24, Phase I); affirmed by D.C. Circuit in City of Chicago et al. v. FPC (No. 23740) issued December 2, 1971; certiorari denied April 17, 1972.

rates. Firm rates are typically comprised of two parts: a demand charge consisting of a flat monthly payment based on the amount the customer nominates to take and the pipeline promises to deliver, and a commodity charge consisting of a unit price per Mcf based on the actual volume taken by the customer. Demand and commodity charges may vary among different types of customers purchasing from the same pipeline. Interruptible rates typically include only the commodity charge.

How to allocate a pipeline's overall cost of service between its jurisdictional and nonjurisdictional (direct industrial) customers, and between the demand and commodity portions of its rates, has been a major function of rate design. In 1952 the FPC adopted what is known as the Atlantic Seaboard formula.[1/] Under this method, 50% of fixed overhead costs are classified as demand and allocated among different classes of sales according to peak load demand; the remaining 50% of fixed costs -- plus all costs varying with volume (principally gas purchase costs) -- are classified as commodity and allocated to all sales on a volumetric basis.

The Commission applied the Atlantic Seaboard method without substantial change for several years. However, in the late 1950's and early 1960's, a number of pipelines pressed for modifications which would assign a larger proportion of costs to the demand portion of rates, thereby lowering the commodity portion and encouraging greater sales to interruptible industrial customers. With gas plentiful in those years, the FPC permitted

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1/ Atlantic Seaboard Corp. et al., 11 FPC 43 (1952).

a "tilting" of costs to the demand charge in several cases in an effort to improve pipeline load balances through encouraging lower-priced industrial sales in summer or valley periods when residential and commercial heating demand is low. The result was to greatly accelerate the industrial demand for gas. Many of the Commission's "tilting" decisions were bitterly opposed by the coal interests which stood to lose, and did lose, boiler fuel markets to cheaper-priced gas. There is no question that the FPC's past rate design policies contributed -- along with restrictions on well-head prices -- to an enormous growth in the burning of gas for electric power generation and other industrial uses, which today account for over half of total U.S. gas consumption.

Now, with gas in short supply, the FPC is taking another look at its rate design precedents. Several events in the last year and a half portend a new direction in the FPC's approach. In April 1971, the Commission announced that it proposed to reexamine existing commodity rate levels and, to the extent necessary, redesign commodity-demand rate relationships in present and future pipeline rate cases.[1/] More recently, in an opinion involving rates of El Paso Natural Gas Co., the Commission reversed a previously approved procedure and instead shifted back to the Atlantic Seaboard approach without modification so as to load greater costs onto the commodity portion of the rates. At the same time the Commission stated its resolve to thoroughly review cost classification and techniques in light of the current gas shortage.

1/ Order No. 431, dated April 15, 1971.

"Our purpose will be to arrive at a method of cost classification and allocation and rate design which will produce a strong economic pressure toward a more efficient allocation of our fuel reserves. This will be directed particularly to conserving gas for residential, commercial and other uses for which this clear fuel is greatly needed and discouraging the use of gas for large volume industrial and boiler fuel purposes." 1/

Tangible evidence of the FPC's change of direction came a few months later when the FPC Staff, in a pending pipeline rate proceeding, proposed a new rate design approach which would scrap the Atlantic Seaboard method entirely (with or without modifications) and instead allocate overall cost of service on a volumetric basis.2/ In the case involved, the result would be to shift over $4 million to the pipeline's direct industrial sales and away from its jurisdictional sales for resale.

While major rate design changes seem certain to be adopted by the FPC in the near future, it should be noted that such changes will be directed towards reducing gas demand rather than increasing overall supply.3/

C. Pipeline Certificates

Pipeline applications for certificates to construct and operate facilities for new or expanded service are appraised by the FPC in terms of four basic criteria: existence of a market for the service proposed,

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1/ Opinion No. 600-A, issued May 8, 1972 in re El Paso Natural Gas Co. (RP69-6, Phase II et al.).

2/ Testimony of Staff witness Robert Scarborough, served July 1972 in United Gas Pipe Line Co. (RP72-75).

3/ Another indicated change in FPC policy regarding pipeline rates is the requirement of incremental pricing for high-cost supplemental sources of nonconventional supply. This change is described in a later section of this chapter concerning FPC regulation of imported gas.

adequacy of reserves to support the proposed service, economic feasibility of the project, and financeability. In many cases, these criteria are satisfied with little difficulty, and certificates are issued without opposition or hearing.[1/] In some cases, the FPC has delayed certification until the pipeline applicants have perfected their evidence with respect to markets and reserves. In other cases, however, problems have arisen, and major projects have been denied by the Commission. Also, where there are competing proposals to serve the same markets, the FPC must choose between them.

Some examples of major pipeline proposals which have failed to receive FPC approval are: (1) a $151 million joint project ("Rock Springs" project) of El Paso Natural Gas Co. and Colorado Interstate Gas Co. to transport gas from the Rocky Mountain area to Southern California -- rejected by the Commission in 1963 because of the lack of immediate need for much of the gas and the desirability of exploring more economical means for increasing service to the Southern California market;[2/] (2) a $62 million project (the Oklahoma-Illinois project) sponsored by certain large integrated petroleum companies to transport gas from northwest and southeast Oklahoma to serve primarily industrial users in the St. Louis area -- rejected by the Commission in 1965 because of a potentially adverse

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1/ The FPC also has a procedure for granting "budget-type" certificates to pipelines for the routine construction of unspecified facilities over a 12-month period. At present, construction under such certificates is limited to $1 million for each single project ($1.75 million for offshore projects) and to a total of $7 million over the 12-month period.

2/ FPC Opinion No. 393 issued July 12, 1963 in re El Paso Natural Gas Co. et al. (G-16235 et al.); 30 FPC 77.

impact on the existing pipeline supplying that area and a too expensive duplication of existing facilities;[1/] (3) a $314 million project sponsored by a newly created subsidiary of Tennessee Gas Pipeline Co. (the Gulf Pacific project) to carry nearly 865 million cubic feet a day from the Texas Gulf Coast area for direct sale to Southern California Edison Co. and the Los Angeles Department of Water and Power for boiler fuel use -- rejected by the Commission in 1966 in favor of an alternative proposal (by the two existing interstate pipelines serving the Southern California area) which was found to better match the market needs of the area, involve lesser expense, provide a greater flexibility in end-use of the gas and avoid certain other problems;[2/] and (4) a $127 million common carrier pipeline (the "Red Snapper" project) sponsored by some 30 companies engaged in offshore Louisiana exploration to provide large volume transportation of offshore gas to onshore buyers -- rejected by the Commission in 1967 because of the refusal of the producing company sponsors to disclose offshore reserve data to support either the route or the capacity of the proposed line.[3/]

Notwithstanding these examples of rejected pipeline projects, an essential fact to be kept in mind is that no area of this country within economic reach of a pipeline (with the possible exception of isolated communities) has gone without gas for lack of pipeline facilities to transport

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1/ FPC Opinion No. 474 issued September 9, 1965 in re Natural Gas Pipeline Co. of America (CP62-243 et al.), 34 FPC 771.

2/ FPC Opinion No. 500 issued July 26, 1966 in re Transwestern Pipeline Co. et al. (CP63-204 et al.), 36 FPC 176.

3/ FPC Opinion No. 528 issued September 26, 1967 in re Tennessee Gas Pipeline Co. et al. (CP65-356 et al.), 38 FPC 691.

the supply. As a general rule, the cost of service ratemaking method gives pipelines a built-in motivation to expand their facilities, whenever economically feasible, since the added investment enlarges the rate base on which they earn a return. The FPC, in turn, was strongly motivated throughout the 1950's and 1960's to allow pipeline expansions because of the lower unit costs to ultimate consumers resulting from increased throughput and thereby, higher load factor.

In recent years, the FPC has tended to relax its supply standard for pipelines seeking to connect new sources of reserves. Initially, during the 1950's, the Commission required that a pipeline, in order to obtain a certificate of public convenience and necessity, show sufficient committed gas reserves to deliver annual market requirements for a period of 12 years. In ensuing years, this so-called 12-year deliverability rule was protested by various pipelines on the ground that it forced them to contract for excess supplies and to pay for gas they could not take.[1/] In 1964, the Commission modified the 12-year rule to provide for greater flexibility in the case of established pipelines with active gas procurement organizations and with systems extending into production areas of continuing exploration. At the same time, however, the FPC continued to require that new pipelines, and existing pipelines proposing to serve new or expanded markets with new sources of supply over new routes, show a minimum deliverability life of 12 years for the incremental supply.

1/ Gas purchase contracts between pipelines and producers typically contain 100% take-or-pay provisions requiring the buyers to pay for daily quantities specified in the contracts irrespective of whether these quantities can in fact be physically taken and sold by the buyer.

With a drying up of uncommitted reserves available for purchase by interstate pipelines in the past few years, the 12-year deliverability standard has become increasingly difficult to meet. In 1972 the FPC certificated two projects to attach new sources of supply, neither of which came even close to satisfying the 12-year requirement.[1/] One project proposed by Arkansas Louisiana Gas Co. involving a 300-mile line to attach new reserves in the Anadarko Basin of Oklahoma and Texas reflected a deliverability life of seven to eight years; the other -- a proposal by Northern Natural Gas Co. to acquire new reserves in Montana via exportation and importation through Canada -- reflected a deliverability life of from four to ten years, depending on assumptions as to estimated underlying reserves. In each case, the FPC stated that the 12-year rule did not apply because the new supplies were sought to serve existing markets, not new or expanded markets. Leaving aside this distinction, the FPC actions reveal a willingness to reshape or modify past criteria and to certificate new projects backed by a lesser showing of supply adequacy than in earlier years.

In addition, the Commission has recently certificated certain other construction projects to permit increased sales where the pipeline involved has shown a deliverability life of only about four years. In at least one case, however, the certificate was conditioned to require elimination of the cost of the new facilities from the pipeline's cost of service

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1/ FPC Opinion No. 612, issued February 18, 1972 in re Arkansas Louisiana Gas Co. (CP70-267); FPC Opinion No. 618, issued May 11, 1972 in re Northern Natural Gas Co. et al. (CP70-69 et al.).

if the increase in deliveries turned out to be less than projected due to inadequate supply.[1/]

In short, the history of pipeline certificate regulation to date does not indicate any major problems arising from lack of capacity to move supplies to market.

D. Abandonments

With respect to abandonments, the Supreme Court in 1960 affirmed an FPC decision that producers may not terminate sales upon expiration of their contracts but rather are obliged to continue deliveries unless cessation thereof can be justified in a Section 7(b) proceeding.[2/] (The Court also ruled, however, that a producer may file a unilateral rate increase for a sale continuing after the contract termination date.) The effect of the Court's decision was to require the continued flow of produced gas, once dedicated to the interstate market, irrespective of contract term. Armed with this judicial precedent, the FPC over the years has routinely permitted abandonment of producer sales for reasons of depletion of supply or uneconomical production, but generally not for other reasons. In addition, the FPC has required pipelines to continue purchasing gas -- even at

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1/ E.g., (1) FPC Opinion No. 574-A issued May 8, 1970 in re Transwestern Pipeline Co. et al. (CP67-220 et al.); FPC order issued January 6, 1971 in re Columbia Gulf Transmission Co. et al. (CP71-77 et al.).

2/ Sunray Mid-Continent Oil Co. v. FPC, 364 U.S. 137 (1960).

higher rates filed unilaterally by the sellers upon contract expiration -- which the producers must continue to sell.[1/]

During the past year, the FPC has granted substantial rate increases to one producer to continue sales which the producer had sought to abandon because of economic infeasibility.[2/] Certain other abandonment applications have been set for formal hearing to determine what prices might be necessary to permit continuation of sales on an economic basis.

In addition, the FPC is now considering a proposal to grant relief from area rate ceilings for sales from reservoirs where a reduction in pressure, a need to recondition wells or a need for deeper drilling makes further production uneconomic at existing prices. The objective of the proposal is to provide producers with an alternative to seeking abandonment for economic reasons under Section 7(b) of the Natural Gas Act.

E. Interconnection of Facilities

As previously indicated, Section 7(a) of the Act empowers the FPC to direct a pipeline company to extend or improve its transportation facilities, and to establish physical connection with and sell gas to any

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1/ A case involving this issue arose in the early 1960's, a time of more abundant supply, when an interstate pipeline sought to discontinue purchases at a unilaterally increased rate filed by the producer-seller after expiration of their contract. The FPC held that the power to compel continuation of sales would be meaningless without the correlative power to compel the continuation of purchases. FPC Opinion No. 426, in re Continental Oil Co. (CI63-979), issued May 5, 1964; affirmed by U.S. Supreme Court on 11/14/66 in United Gas Pipe Line Co. v. FPC, Oct. Term 1966, No. 49.

2/ FPC order dated June 14, 1972 in re Banquete Gas Co. (CI68-703).

company or municipality legally authorized to engage in the local distribution of gas. However, it is expressly provided that the Commission does not have authority to compel the "enlargement" of transportation facilities or the establishment of physical connections and sales if the result would be to impair a pipeline's ability to render adequate service to its customers.

Over the years, the FPC has granted numerous requests by municipalities and other distributors for orders directing service by an adjacent or nearby pipeline. Until the last few years, many of these requests were unopposed by the pipeline involved. Where there was opposition by the pipeline or some other party, the FPC considered the extent of the facilities required by the pipeline to establish connection, the economic feasibility of the proposal, and the impact of the requested service on the pipeline's operations in determining whether to order physical connection and sale of gas.

In the past two years or so, greater opposition has developed to the granting of Section 7(a) requests for allocations of gas, particularly where the gas would be used to service industrial customers, because of the shortage of supply. Several pipelines have contended that they should not be required to attach new loads under Section 7(a) when they have insufficient gas to meet incremental needs of existing customers. The FPC has accepted this argument in certain recent cases, ruling that approval of Section 7(a) requests would impair the pipeline's ability to render adequate service to existing markets.

F. End-Use Regulation

In view of the increasing shortage of gas supply and suggestions that the FPC allocate available supply by end-use, a brief review of the Commission's powers and past policies in this area may be useful.

Generally, questions of end-use have arisen in connection with direct industrial sales by pipelines (or by producers, with transportation provided by an interstate pipeline to the ultimate user) for boiler fuel.[1/] The FPC has no authority directly over direct industrial sales. However, it does have certificate authority over the transportation of gas in interstate commerce, whether for direct sale or sale for resale, and over the construction of facilities to transport gas in interstate commerce. Thus, through this means, the Commission may prevent -- and has done so on a number of occasions -- the direct sale of gas by pipelines for industrial uses deemed contrary to the public interest.

Over the years, the FPC has had no uniform policy concerning the usage of gas for boiler fuel or other industrial purposes -- to the extent it could control such usage through its certificate authority. Many certificates have been issued to pipelines for the construction of facilities to transport gas destined for sale to electric utilities and others for the generation of electricity. For example, much of the pipeline capacity serving the Florida market was authorized for the purpose of transporting gas purchased directly in Texas and Louisiana by the two major electric utilities in Florida, their usage of capacity being considered the

1/ Pipelines also make sales on both a firm and interruptible basis to distributors for resale to industrial users.

only means of rendering gas service economically feasible to residential and commercial customers in the State of Florida. In other instances, however, certificates have been denied by the FPC for transportation of boiler fuel gas.

Four examples of such denial are notable.

(1) In 1959, in a decision eventually upheld by the Supreme Court, the FPC denied a certificate to Transcontinental Gas Pipe Line Corp. for construction of facilities to transport 50,000 Mcf/d of gas purchased in Texas by Consolidated Edison Co. of New York for exclusive use as boiler fuel in New York City. The Commission concluded that the contemplated use of gas for boiler fuel constituted an "inferior usage," that the project would preempt pipeline capacity otherwise available to serve "more urgent and widely beneficial public needs," and that the direct purchase-sale type of proposal would tend to exert an upward pressure on the price of gas in the field.[1/] After considerable litigation, including reversal by the Third Circuit Court of Appeals, the Supreme Court held that the FPC had discretion to consider all of these factors in determining whether or not to issue a certificate.[2/]

(2) Also in 1959, the FPC denied authorization to El Paso Natural Gas Co. to transport 100,000 Mcf/d for direct sale to Southern California Edison Co. for boiler fuel use. Instead, El Paso was directed to sell the gas to the two major distributors serving Southern California

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1/ FPC Opinion No. 315, issued January 30, 1959 in re Transcontinental Gas Pipe Line Corp. (G-13143 et al.); 21 FPC 138.

2/ FPC v. Transcontinental Gas Pipe Line Corp., 365 U.S. 1 (1961).

for resale. The FPC held that the proposed direct sale would result in committing too large a portion of El Paso's pipeline capacity to one type of use, would tend to exert upward pressures on field gas, and would preclude state and local authorities from determining how the gas could best be used in the Southern California area as a whole.[1/]

(3) In 1966, the FPC rejected a proposal by Gulf Pacific Pipeline Co. to build a new 1400-mile large diameter line, estimated to cost over $300 million, in order to transport 865,000 Mcf/d from the Texas Gulf Coast area to Los Angeles for use as boiler fuel by Southern California Edison Co. and the Los Angeles Department of Water and Power.[2/] At the same time, however, the Commission authorized a competing proposal by the two existing pipelines serving the Southern California market to increase deliveries to the local distributor. The Gulf Pacific project was rejected on the grounds that it would impede the conversion of present gas burning electric generating plants in the Los Angeles area to nuclear and other fuels; result in detrimental competition for the local gas distributor; and encourage producers to withhold large blocks of gas from the interstate market in order to make nonjurisdictional sales at higher prices. The FPC also concluded that use of the entire Gulf Pacific volume for boiler fuel would have no appreciable effect in alleviating Los Angeles' air pollution problem. Subsequently, virtually all of the gas dedicated to Gulf Pacific -- over 6 trillion cubic feet -- was sold intrastate; the bulk of this gas

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1/ FPC Opinion No. 333 issued November 27, 1959 in re El Paso Natural Gas Co. (G-12580); 22 FPC 900.

2/ FPC Opinion No. 500 issued July 26, 1966 in re Transwestern Pipeline Co. et al. (CP63-204 et al.); 36 FPC 176.

is probably now being consumed under steam-electric plant boilers or in other industrial operations in the State of Texas.

(4) In 1972, the FPC denied an application by El Paso Natural Gas Co. to transport 32,000 Mcf/d of gas purchased by Arizona Public Service Co. for use as boiler fuel in certain electric generating plants in the Phoenix area. As in the cases above, the Commission stressed that the project, if approved, would encourage producers to reserve large packages of gas for direct sale to the highest bidder, with an adverse impact on both the amount and price of gas available for interstate resale markets. The FPC also cited the proposed usage of the gas as a factor against certification.[1/]

The above decisions reveal some inclination on the part of the FPC to regard the use of gas for boiler fuel as inferior compared with residential and commercial use. In no case, however, did the FPC find that boiler fuel usage in the situations involved would make any significant contribution toward reducing air pollution. Rather, as indicated, other factors entered into the Commission's decisions, in particular the impact of direct sales on prices of gas in the field.

Recently, the end-use question has arisen again in connection with federal offshore gas which producers seek to have transported by interstate pipelines for use in onshore refineries and chemical plants, partly as boiler fuel and partly as feedstock or fuel in processing operations. While pipeline transportation arrangements for producers

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1/ FPC Opinion No. 615 issued March 22, 1972 in re El Paso Natural Gas Co. (CP71-234).

are not new and have been approved in the past, the gas shortage situation has led distributors (and certain state commissions) in Eastern Seaboard states to claim that federal offshore supply should be reserved for interstate resale markets and not diverted to local industrial use.

In the first contested case where this claim was advanced, the FPC decided to approve the proposed transportation of offshore gas to a producer refinery in Mississippi on the ground that the ability of a producer to use its own gas in refinery and chemical plant operations would provide incentive to explore for and develop additional gas reserves, part of which will be excess to the producer's requirements and hence will become available for sale to the interstate market.[1/] This decision was upheld last May by the Court of Appeals for the D.C. Circuit which agreed that the desirability of providing incentive to seek additional supplies outweighed any considerations of end use.[2/]

The same issue is now pending in another FPC proceeding where three pipelines are seeking authority to transport Federal Domain gas reserved by certain producers for their own use in onshore facilities. Questions to be resolved by the FPC include: whether the proposed use of the gas in producer refineries and petrochemical complexes is superior or inferior to the use which would be made of the gas by interstate pipeline customers (many of whom resell large volumes to industrial users); the degree to which the proposed use actually creates incentive for further

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1/ FPC Opinion No. 560-A, issued December 31, 1970 in re Chandeleur Pipeline Co. (CP69-76), 44 FPC 1747.

2/ PSC of New York v. FPC, CADC, No. 71-1197, issued May 16, 1972.

exploration and development; and whether denial of the transportation certificates would impede the development of offshore sources of supply by other producing interests. These questions involve both the stimulation of additional supply and the allocation of existing supply.

G. Curtailments

A corollary to end-use regulation is the authority of the FPC to control curtailments and allocation of supplies available to pipeline companies. These matters have cropped up on various occasions in the past, but they have assumed critical importance in the last few years as a result of plans submitted by nearly all major pipelines for curtailing deliveries in the event of insufficient supply to meet contractual obligations. The basic problem presented to the FPC is to provide for a fair allocation of supplies among all customers of an interstate pipeline in times of gas shortage.

The scope of the FPC's jurisdiction was contested in the first curtailment proceeding -- involving United Gas Pipe Line Co. -- to come before it in recent years. As noted in the previous section, the FPC has no authority directly over sales by pipelines to direct industrial customers. Citing this absence of authority, a group of United's direct industrial customers contended that the FPC had no power to approve plans for reducing sales to direct customers below contract quantities. The Commission claimed, on the other hand, that it had authority to control curtailments, and hence allocation of supplies, to both direct and resale customers by virtue of its jurisdiction over transportation of gas in interstate commerce and its power

under Sections 4 and 5 of the Natural Gas Act to prohibit discriminatory practices. The FPC's position was rejected by the Fifth Circuit Court of Appeals which held that the Commission's jurisdiction was confined to initial certification and to abandonment of facilities used to make direct sales, with no continuing jurisdiction between these two functions.[1/]

Because of the importance of this issue, the FPC requested -- and was granted -- expedited review of the Fifth Circuit decision by the Supreme Court. In an opinion handed down on June 7, 1972, the Supreme Court ruled in favor of the Commission.[2/] Specifically, the Court held that the FPC's authority over gas transportation gives it power to approve curtailment of deliveries to direct sales customers, and that language in the Natural Gas Act exempting direct sales from regulation applies only to rate authority and not to transportation authority. Among other things, the Supreme Court pointed out that if a pipeline's direct industrial sales were wholly exempt from any curtailment plan approved by the FPC, the company's resale customers would be forced to bear the entire burden of reduced deliveries. In the case at hand, the Court found the evidence to show that this burden could not be borne by resale customers alone without jeopardizing service to homes, schools, hospitals and other such customers. The Supreme Court further observed that a seriously inequitable system of gas distribution would result if direct industrial customers could demand full contract

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1/ Louisiana Power & Light Co. v. United Gas Pipe Line Co., C.A. 5, No. 71-2550, decided January 14, 1972.

2/ FPC v. Louisiana Power & Light Co., U.S. Supreme Court, No. 71-1016, decided June 7, 1972.

volumes at the same time that homes, hospitals and schools suffered from inadequate service.

The significance of the Supreme Court's holding is illustrated by the fact that, to date, 28 pipelines have filed curtailment plans for FPC approval.[1/] These pipelines include all major interstate transmission companies in the U.S. except Tennessee Gas Pipeline and Transwestern Pipeline Co. Moreover, eight pipelines were forced to curtail sales made on a firm basis during the year ended March 31, 1972, and 15 pipelines project firm delivery curtailments in an aggregate amount of about one trillion cubic feet during the year ending March 31, 1973. The one trillion cubic feet represents close to 10% of the total annual sales made by the 15 companies in 1970.

Table IV-2 on the following page depicts the extent of curtailment of firm service experienced and projected by individual pipelines in reports submitted to the FPC. The company with the most severe supply deficiency is United Gas Pipe Line. This deficiency, in turn, accounts for much of supply shortfall experienced by Texas Eastern Transmission, a major pipeline customer of United, and by Algonquin Gas Transmission Co., supplied entirely by Texas Eastern. United's difficulties have also contributed to the supply problems of other pipelines which it serves.

1/ Most of these plans were filed in response to FPC Order No. 431, issued April 15, 1971, directing jurisdictional pipelines to take all necessary measures to protect adequate and reliable service, including (a) consideration of curtailment of all interruptible and large boiler fuel sales where alternate fuels were available, and (b) submission of reports regarding present or proposed curtailment procedures.

TABLE IV-2

FIRM REQUIREMENT DEFICIENCIES REPORTED
BY INTERSTATE PIPELINES TO FPC STAFF

Company	Actual April 1971-March 1972	Projected April 1972-March 1973
	(Bcf)	
Algonquin Gas Transmission Co.	2.1	13.5
Arkansas Louisiana Gas Co.	75.2	149.1
Cities Service Gas Co.	38.0 a/	28.0 a/
Colorado Interstate Gas Co.	None	1.8
Consolidated Natural Gas System	None	23.9 b/
Eastern Shore Natural Gas Co.	None	0.1
El Paso Natural Gas Co.	None	33.1
Mississippi River Transmission Corp.	None	2.1
Natural Gas Pipeline Co. of America	83.9 c/	149.8
Northern Natural Gas Co.	None	6.3 b/
Panhandle Eastern Pipe Line Co.	--	25.5
Texas Eastern Transmission Corp.	18.7	90.9
Transcontinental Gas Pipe Line Corp.	88.1	96.2
Trunkline Gas Co.	43.4	97.6
United Gas Pipe Line Co.	154.3	348.4

a/ Described by the company as "normal."
b/ Alternate lower figures were also reported.
c/ Summertime curtailments.

Note: These figures should not be added because of duplications among companies.

Source: Speech of FPC Chairman John Nassikas to INGAA Convention in Puerto Rico, October 24, 1972, Table 1.

Six companies account for over 87% of the total projected deficiency for the year ending March 31, 1973: United Gas Pipe Line Co., Natural Gas Pipeline Co. of America, Arkansas Louisiana Gas Co. Trunkline Gas Co., Transcontinental Gas Pipe Line Corp. and Texas Eastern Transmission Corp. Leaving aside Arkansas Louisiana which primarily serves the State of Arkansas, the impact of firm delivery curtailments will be felt largely in Eastern Seaboard and Midwest gas markets.[1/]

Because of sales between pipelines and the chain effect of a deficiency for one pipeline company in causing a deficiency for others, the figures in Table IV-2 overstate the total impact of firm sale cutbacks experienced by pipeline customers. On the other hand, the figures do not reflect curtailment of interruptible industrial sales which have been drastically reduced in the case of some companies. For example, Mississippi

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1/ The specific geographic areas served by the six pipelines are as follows:

United Gas Pipe Line: Southern Louisiana, Southern Mississippi, Southern Alabama, Northwest Florida.

Natural Gas Pipeline Co.: primarily the Chicago area, including nearby communities in Indiana and northern Illinois.

Arkansas Louisiana: Northern Louisiana, Arkansas, northeast corner of Texas.

Trunkline Gas Co.: A corridor extending northeasterly through Louisiana, northwestern Mississippi, western Tennessee, south central Illinois, northwestern Indiana and Michigan.

Transcontinental Gas Pipe Line: A corridor extending northeasterly from the Texas Gulf Coast across southern Louisiana, Mississippi, Alabama, and then northward through Atlanta, Winston-Salem, Washington, D.C., Baltimore, and Philadelphia to New York City.

Texas Eastern Transmission: A corridor extending from the Texas Gulf Coast across southern Louisiana, Mississippi, central Tennessee and Kentucky, southeastern Ohio, southern Pennsylvania, New Jersey and into New York City. Algonquin, a Texas Eastern affiliate serves southern New England, including the Boston area.

River Transmission Corp., which forecasts a deficiency in firm gas supply of only about 2.1 billion cubic feet for the year ending March 31, 1973, has advised that it plans no interruptible sales at all during the 1972-1973 winter months. Historically, more than half of Mississippi's mainline industrial sales have been interruptible. It should also be kept in mind that virtually all major interstate pipelines, whether or not they have found it necessary to invoke curtailments, have instituted partial or complete restrictions on new sales and/or on increased sales to existing customers.

The substantial impact of the gas shortage on the interruptible segment of the gas market -- consisting primarily of sales to electric generating plants and other large industrial customers with facilities to burn alternate fuels -- is further revealed by the curtailment plans which have been filed by interstate pipelines with the FPC. The nature and status of these plans are summarized on Table IV-3. While provisions vary depending upon the composition of the markets served by each pipeline (interruptible versus firm, direct versus resale, industrial versus residential and commercial), the plans are generally of two types: those providing for curtailments according to end-use categories, and those providing for ratable curtailments of all deliveries. However, most of ratable curtailment plans would be implemented only after cutoff of all interruptible sales. The majority of the end-use programs similarly accord lowest priority to interruptible usage and to large volume industrial usage, particularly where alternate fuels can be used.

CURTAILMENT PROVISIONS AND PLANS FILED BY INTERSTATE PIPELINES WITH FPC

Pipeline	Date Plan Filed	Plan Implemented	Description of Curtailment Plan	FPC Status
Algonquin Gas Transmission Co. (RP71-131)	May 1971	Curtailments began in December 1971. Rate of curtailment depends on degree of curtailment by Texas Eastern Transmission Corp. Anticipated curtailment rate in 1972-1973 is 10%.	Prorata reduction of deliveries.	Settlement conferences to go forward upon resolution of curtailment procedures of Texas Eastern Transmission, Algonquin's sole supplier.
Alabama-Tennessee Natural Gas Co. (RP71-138)	May 1971	No	Prorata reduction of deliveries, after curtailment of all interruptible sales first. (Existing tariff provision.)	Under analysis by FPC Staff.
Arkansas Louisiana Gas Co. (RP71-122)	May 1971	Curtailments began in October 1971. Estimated rate is approximately 150 Bcf per year.	End-use curtailment, as follows (from lowest priority to highest): (a) all interruptible sales (b) large volume industrial sales where alternate fuels can be used (c) large volume industrial sales where alternate fuels cannot be used (d) small industrial and commercial sales (e) sales to residential and other "human needs" customers.	Hearings held in July and August 1971. Rejection of plan recommended by an FPC Examiner in October 1971 due to possibility of discriminatory and preferential application. Plan is now pending FPC decision.
Bluefield Gas Co. (RP72-94)	October 1971	No	End-use curtailments, as follows (from lowest priority to highest): (a) interruptible service (b) "curtailable" service (c) remaining industrial service (d) service to domestic and other "human needs" customers.	Under analysis by FPC Staff.
Cities Service Gas Co. (RP71-129)	May 1971	Projects curtailment of 28 Bcf in year ending March 1973.	End-use curtailment of interruptible deliveries (large volume sales for electric generation, smaller volume sales for electric generation, sales to direct consumers and utilities, sales to commercial customers), followed by "simultaneous and equitable" curtailment of firm deliveries.	Under analysis by FPC Staff.
Colorado Interstate Gas Co. (RP71-135)	May 1971	No	End-use curtailment, as follows (from lowest priority to highest): (a) interruptible service, direct and resale (b) firm service to resale customers for interruptible industrial use (c) firm service to direct and resale customers for firm industrial use (d) firm service for domestic and commercial use (Existing tariff provision.)	Approved by FPC in September 1971.
(RP72-122)	May 1972	Projects curtailment of 1.8 Bcf in 1972-1973 winter.	Curtailment of deliveries for use by or resale to interruptible customers. Plan also provides for meeting of firm growth needs before allocation of any supply for interruptible requirements.	Suspended until October 1, 1972.
Columbia Gas Transmission Co. (RP72-89)	December 1971	No	Ratable curtailment of all firm deliveries (except to small general service distributor customer), but with preference to residential and commercial customers. Interim settlement agreement provides for exemption of volumes required to maintain firm non-industrial customer loads (subject to certain conditions) with surcharges up to $1.65/Mcf for such exempted volumes.	Interim settlement offer approved by FPC in October 1972.

CURTAILMENT PROVISIONS AND PLANS FILED BY INTERSTATE PIPELINES WITH FPC

Pipeline	Date Plan Filed	Plan Implemented	Description of Curtailment Plan	FPC Status
Consolidated Gas Supply Corp. (RP72-47)	October 1971	Projected curtailment of 24 Bcf in year ending March 31, 1973.	End-use curtailments, as follows (from lowest to highest priority): (a) industrial uses which can be converted to alternate fuel (b) "critical" industrial uses which cannot be feasibly converted to alternate fuel (c) industrial usage less than 60 MMcf per year (d) domestic and commercial use.	Formal hearing recommended by FPC Staff.
Eastern Shore Natural Gas Co. (RP72-21)	August 1971	Relatively small curtailment (83 MMcf) anticipated in 1972-1973 winter season.	End-use curtailments, as follows (from lowest to highest priority): (a) interruptible service (including sales to resale customers for interruptible use) (b) firm service to direct pipeline customers (c) firm service for industrial use (except small volume industrial use) (d) firm service to resale and small industrial customers.	Approved by FPC in November 1971.
El Paso Natural Gas Co. (RP72-6)	July 1971	Projects curtailment of 90 Bcf during year beginning November 1, 1972, averaging 247,000 Mcf/d.	End-use curtailments, as follows (from lowest to highest priority): (a) direct industrial sales above firm capacity (b) direct and resale sales for industrial use (c) sales for commercial use (d) domestic and residential use.	Interim curtailment plan prescribed by FPC in October 1972 at El Paso's request. Permanent curtailment plan pending decision.
Florida Gas Transmission Co. (RP71-128)	May 1971	No	End-use curtailment of four classes of interruptible customers, followed by ratable curtailment of firm deliveries. (Existing tariff provision.)	Under analysis by FPC Staff.
Granite State Gas Transmission (RP71-116)	May 1971	No	Ratable curtailments, but with preference to residential and commercial customers.	Accepted for filing.
Great Lakes Gas Transmission Co. (RP71-134)	May 1971	No	Ratable curtailment of deliveries.	Under analysis by FPC Staff.
Lone Star Gas Co. (RP72-15)	May 1971	No	End-use curtailments, as follows (from lowest to highest priority): (a) oil field sales (b) direct interruptible sales (c) residential and commercial service.	Under analysis by FPC Staff.
Louisiana-Nevada Transit Co. (RP72-13)	July 1971	No	Ratable curtailment of firm deliveries (although with priority to domestic users), after curtailment of all interruptible deliveries.	Rejection of plan recommended by FPC Examiner in February 1972. Proceeding remanded by FPC in October 1972.
Michigan Wisconsin Pipe Line Co. (RP71-117)	May 1971	No	Ratable curtailments, except that seller may first require buyers to reduce or discontinue interruptible loads in excess of 200 Mcf/d. (Existing tariff provision.)	Approved by FPC in September 1971.
Mid-Louisiana Gas Co. (RP71-139)	May 1971	No	End-use curtailments, as follows (from lowest to highest priority): (a) interruptible customers (b) industrial usage (c) domestic consumption.	Approved by FPC in April 1972.

CURTAILMENT PROVISIONS AND PLANS FILED BY INTERSTATE PIPELINES WITH FPC

Pipeline	Date Plan Filed	Plan Implemented	Description of Curtailment Plan	FPC Status
Mississippi River Transmission (RP73-6)	July 1972	Projects firm curtailments of 6.5 Bcf during year ending March 1973.	End-use curtailments, as follows(from lowest to highest priority): (a) sales for electric generation (b) direct interruptible industrial sales (c) resale interruptible industrial sales (d) firm industrial deliveries exceeding 1,000 Mcf/d (e) firm industrial deliveries less than 1,000 Mcf/d (f) remaining resale service.	Hearings began in October 1972.
Natural Gas Pipeline of America (RP70-42)	June 1970	Voluntary curtailments of 11.3 Bcf in 1970. Curtailment of 183 Bcf for 12 months ended August 1971. Total curtailment of 167 Bcf forecast for following year.	Ratable curtailments, after voluntary relinquishments by larger customers.	Settlement approved by FPC in November 1971.
Northern Natural Gas Co. (RP71-107)	April 1971	Projected curtailments of 2.3 Bcf in summer of 1971 and 6.3 Bcf in summer of 1972.	Discontinuation of interruptible deliveries for large volume consumers (specifically, 12 electric generating plants) using over 25,000 Mcf/d equivalent, with ratable curtailment thereafter up to 15% of contract demand in April and October and up to 30% of contract demand in months of May through September. Subsequent settlement offer provides for end-use curtailment of sales for electric generation and large volume interruptible sales in winter months, and ratable curtailment up to 15% of contract demand in summer months -- with any further curtailments to be made according to winter plan.	Settlement offer approved by FPC in October 1972.
Panhandle Eastern Pipe Line Co. (RP71-119)	May 1971	Projected curtailments of 14.6 Bcf through March 1972 and 25.5 Bcf for year ending March 1973.	Ratable curtailment of industrial sales and sales for electric generation, direct and resale. "Human needs" and small resale customers are exempt.	Interim curtailment plan (essentially apportioning two-thirds of curtailment volumes to resale customers and one-third to direct industrial customers) approved by FPC in November 1971. Extenings on permanent curtailment plan held from November 1971 to August 1972. Plan awaiting Examiner's decision.
Shenandoah Gas Co. (RP71-141)	June 1971	No	End-use curtailments, with highest priority to domestic customers. (Existing tariff provision.)	Under analysis by FPC Staff.
Southern Natural Gas Co. (RP72-74)	November 1971	No	End-use curtailments, as follows from lowest to highest priority): (a) sales to electric generating plants with alternate facilities (b) interruptible sales (c) firm industrial sales (d) remaining sales.	Hearings began in March 1972.
Texas Eastern Transmission Corp. (RP71-130)	May 1971	Curtailments commenced at rate of 100,000 Mcf/d in December 1971. Beginning in May 1972, anticipated curtailment rate is 250,000 Mcf/d (or 10%).	Ratable curtailment of all deliveries. Interim settlement proposal exempts small customers and provides for exemptions for other buyers to extent required to protect residential and commercial loads.	Interim settlement proposal (extending to September 1973) pending before FPC.
Texas Gas Transmission Corp.	May 1971	No	Ratable curtailment of all sales in proportion to quantity entitlements determined for each customer in winter and summer periods. Interim settlement agreement provides for 100% curtailment of interruptible requirements before any curtailment of firm requirements.	Interim settlement agreement (extending through April 1973) approved by FPC in June 1972.

CURTAILMENT PROVISIONS AND PLANS FILED BY INTERSTATE PIPELINES WITH FPC

Pipeline	Date Plan Filed	Plan Implemented	Description of Curtailment Plan	FPC Status
Transcontinental Gas Pipe Line (RP71-118)	May 1971	Curtailments commenced in June 1971 and have ranged up to 12% or more of firm deliveries at various times.	Curtailment of all interruptible sales, followed by ratable curtailment of firm deliveries (except small volume customers). Interim one-year settlement plan provided for partial or complete exemptions from curtailments in winter months to extent required to protect firm markets, with such exemptions to be balanced out by reduced takes on other days.	Interim settlement (extending to November 1972) approved by FPC in November 1971.
(RP72-99)	January 1972	Projected curtailments of 95 Bcf in year ending March 1973.	Curtailment of all interruptible sales, followed by ratable curtailment of firm deliveries (except small volume customers) but with exemptions from curtailments in winter months if required for protection of firm markets. Supplemental procedure provides for end-use curtailments (all interruptible markets first) in winter months.	Further interim settlement (extending to November 1973) approved by FPC in November 1972.
Trunkline Gas Co. (RP71-100)	April 1971	Curtailments began in winter 1971. Projected total curtailment of 50 Bcf through March 1972 and 98 Bcf in year ending March 1973.	End-use curtailments, as follows (from lowest to highest priority): (a) interruptible sales (b) large volume firm sales (c) small volume firm sales	Under analysis by FPC Staff.
United Gas Pipe Line Co. (RP71-29, RP71-120)	October 1970 (revised in May 1971)	Curtailments began in November 1970. Curtailments totalled 154 Bcf in year ending March 1972. Projected curtailments of 348 Bcf in year ending March 1973.	End-use curtailments, as follows (from lowest to highest priority): (a) direct industrial and power plant sales at rates lower than applicable city gate zone rates at 100% load factor (b) sales for industrial end-use (except "process use"), including gas used to generate electricity for industrial purposes (c) gas used to generate electricity for domestic consumers (d) sales to industrial customers for "process use" (e) gas used by domestic consumers.	Various interim curtailment plans approved by FPC. FPC asserted jurisdiction over pipeline curtailments in October 1971 (Opinion 606). Jurisdiction upheld by Supreme Court in June 1972. FPC rejected lowest priority category proposed by United and remanded other issues concerning implementation of plan to Examiner for initial decision. Examiner approved plan in July 1972 subject to subdivision of domestic consumer category into residential and commercial groups, and higher priority for gas used to generate electricity for domestic loads than for "process use" industrial gas.

H. Imports and Exports

Exportation and importation of gas into the United States require FPC approval under Section 3 of the Act.

At the present time, exports of gas from this country are relatively insignificant, amounting only to 30 billion cubic feet in 1971 (compared with imports of 932 billion cubic feet). This figure does not include exportation of approximately 50 billion cubic feet annually of LNG, begun in 1969, by Phillips Petroleum Co. and Marathon Oil Co. from Alaska to Japan.

Imported gas is derived from two principal sources: by overland pipeline from Canada, and by tanker in liquefied form from overseas nations. In addition, some LNG has been imported on a spot basis via tanker trailer from Canada. However, the volumes involved here are extremely small, and such shipments are not considered to constitute anything more than sporadic supplies available from time to time to meet peak day needs in certain localized markets (principally in New England). The U.S. also currently imports some gas from Mexico but, here again, the volumes are now, and are expected to remain, insignificant.

Pipeline imports of gas from Canada commenced in the early 1950's but were exceeded by exports to Canada until 1958. Since that time, net imports from Canada have risen from about 56 billion cubic feet to 897 billion cubic feet in 1971, representing about 3.9% of total U.S. consumption (excluding Alaska) in that year. Substantially increased imports from Canada would be a highly desirable means of supplementing U.S. gas supply. However, the extent of any further increase is subject to two major

uncertainties: the current export policy of the Canadian National Energy Board (which will approve export of only those surplus volumes determined to exceed the reserves needed to maintain the level of current Canadian market requirements for almost 30 years in the future), and the magnitude of future discoveries in Canada.

LNG imports by tanker commenced on a spot basis for peak shaving (extreme cold day) needs in 1968. To date, the import volumes have been very small. However, two long-term projects have been authorized by the FPC in the past year. Several more projects are proposed. The degree to which such projects will supplement U.S. gas supplies in the coming years will depend both on the regulatory approach followed by the FPC and on policies adopted by other regulatory bodies.

1. Pipeline Imports from Canada

Gas moved across the international border into the U.S. requires not only import authorization from the FPC but also export authorization from the Canadian National Energy Board.[1/] Also, authorization must be obtained from the Alberta Energy Resources Conservation Board for the removal of gas from the Province of Alberta, the major producing region in Canada to date.

Beginning in 1955 with the issuance of authority to Pacific Northwest Pipeline Co. (subsequently merged by El Paso Natural Gas Co.) to import and authority to Westcoast Transmission Co. Ltd. to export 300,000 Mcf/d at a point on the United States-Canadian boundary near

1/ All export licenses granted by the National Energy Board are subject to the approval of the Governor-in-Council.

Sumas, Washington, several major blocks of gas have been licensed for import and export. The volumes involved have been largely for consumption in U.S. markets in Northern California, the Pacific Northwest and the Upper Midwest area (Minnesota, Wisconsin and Michigan). Some volumes also flow to Montana, New York and Vermont.

While different considerations were apparent on the two sides of the border, no serious conflict between the FPC and NEB in regard to export-import policies developed until 1967. In that year, the two regulatory bodies were presented with a proposal involving an increase in imports by El Paso from Westcoast Transmission at the Sumas border point from the 300,000 Mcf/d level authorized in 1955 to 500,000 Mcf/d. In addition, Westcoast and El Paso agreed to a contract price of 27.0¢/Mcf for the entire volume, thus representing a 5¢ increase over the previously authorized 22¢ rate for the initial import volume of 300,000 Mcf/d. The 22¢ rate was said to have been negotiated under distress conditions in 1954 and to be no longer realistic in view of current market conditions. The NEB approved the new contract in April 1967. Thereafter, on August 10, 1967, the FPC approved the additional imports -- but subject to the condition that the existing imports of 300,000 Mcf/d continue at 22¢ and the incremental imports of 200,000 Mcf/d be priced at 29.5¢.[1/] The 29.5¢ rate was determined by the FPC to be "in-line" with charges by Westcoast for comparable sales to Canadian customers. The FPC also emphasized the importance of price as a prime consideration in certificating gas imports.

1/ FPC Opinion No. 526, issued August 10, 1967 in re El Paso Natural Gas Co. (G-8932 and CP66-315), 38 FPC 311.

> "The importance of price scrutiny takes on added significance in view of the possible availability of additional volumes of Canadian gas for U.S. markets. It is only fair to alert both United States and Canadian interests at an early time that gas imports into the United States will not be approved at unjustifiably high prices." (38 FPC 319)

The FPC decision necessitated reapplication by Westcoast to the NEB for export authority under the conditions imposed by the Commission. The NEB denied this authority on December 22, 1967. In so doing, the NEB announced three criteria for determining whether a proposed price for export of gas is in the public interest, namely, the price must (a) recover the appropriate share of costs incurred by the Canadian transmission company, (b) not be less than the price to Canadian customers in the general area of the proposed export, after allowance for variations in the terms of delivery, and (c) approximate the least cost alternative for energy from indigenous sources in the United States market area. In applying the third test, the NEB found the price of the export gas to be at least 4.5¢ below domestic U.S. gas available to El Paso from the San Juan Basin, and hence unacceptable. The NEB also made clear its position that the so-called "in-line" pricing theory applied by the FPC for evaluating border prices was totally inconsistent with the Canadian public interest.

The impasse created by the above decisions was resolved a few months later when both the FPC and Canadian Government accepted a proposed settlement providing for sale of the incremental import volume of 200,000 Mcf/d at 30.5¢/Mcf. Nevertheless, the controversy illustrates the difference in interests on the two sides of the border and the type of roadblock that can occur.

More recently, the price issue has assumed a secondary role with Canadian denial of several export licenses due to a lack of surplus gas.

The NEB's policy is to approve for export only those volumes which are deemed excess to the quantities required to meet the estimated level of Canadian consumption four years ahead for 25 years. Such excess volumes are designated as "current surplus" available for export. In September 1970, the NEB calculated an insufficient current surplus to meet all then pending export applications. As a result, it granted export requests by four existing transmission companies -- although with reduced terms and other conditions -- and dismissed entirely a new export project mounted by Northern Natural Gas Co. to bring Alberta gas to its system in Minnesota. The NEB explained as follows:

> "In the present circumstances where surplus is not adequate to support all the applications before the Board, nor the whole of the applications of already established transmission systems, the establishment of a new transmission project oriented wholly to export, founded on the cost of service concept, and so devised that its future development would almost inevitably result in decreasing border prices in a period when such gas as may become surplus to Canadian requirements will be increasingly valuable, would not appear to the Board to serve the public interest of Canada."

Subsequently, on November 19, 1971, the National Energy Board rejected a renewed bid by Northern Natural for export authority, together with two other export requests then pending. Together, the rejected applications involved an export total of close to a half billion cubic feet a day and over two and a half trillion cubic feet over the projected license terms of 15 and 20 years. The NEB cited the lack of any current surplus available for export. In fact, in view of rapidly increasing

Canadian demand for gas, the NEB calculated a current deficiency of nearly 1.1 trillion cubic feet for purposes of satisfying its 25- to 30-year protection standard for Canadian requirements.

The NEB's current surplus calculation did not take into account reserves in Canadian frontier areas where estimates of potential reserves are relatively large. Several of these areas are under active exploration at the present time, although there is little definitive information to date respecting the magnitude of announced reserve discoveries. Without substantial new reserve additions in Canada, it appears highly unlikely -- given the NEB's current approach to determining exportable surplus -- that there will be any appreciable increase in U.S. imports of Canadian gas in the future. In fact, as current export license terms expire, the quantities of imported gas could decrease from established Canadian producing areas.

The prospects for increased supplies of Canadian gas will be discussed further in Chapter V.

2. LNG Imports by Tanker

FPC regulation of imported gas in liquefied form from overseas nations is presently in an unsettled state. An initial question concerns the extent of the Commission's jurisdiction in this area. A second question involves the standards to be applied in evaluating LNG projects, while a third issue concerns the terms on which the imported supply is to be made available to U.S. markets. In 1972, the Commission dealt with these questions for the first time in decisions approving two long-term import proposals. In at least one case, however, the Commission's conclusions have

raised considerable uncertainty respecting the future of both imported LNG and other high cost non-conventional sources of gas supply.

Beginning in 1968, the FPC has authorized several short-term imports of LNG -- one or two shiploads per project -- from Algeria or Libya for peak shaving or emergency needs. The prices for these supplies have ranged from approximately 81¢ to $1.70/Mcf in the port of delivery. The FPC simply assumed jurisdiction in approving the various short-term projects, none of which were questioned by any party.

(a) Distrigas Project

The first long-term project considered by the Commission involved a proposal by Distrigas Corp. -- a largely-owned subsidiary of Cabot Corp. -- to import the LNG equivalent of 15.4 billion cubic feet annually from Algeria over a 20-year period. The purpose of the project is to help meet peak shaving needs of distributors in the New England and New York City areas. The LNG supply will be derived from natural gas produced and liquefied by Sonatrach (the Algerian national oil company) and then transported by cryogenic tanker to Distrigas receiving terminals in Boston, Massachusetts and on Staten Island, New York. Distrigas will pay 68¢ per million Btu (plus annual escalations of 0.6¢ per million Btu) at the point of delivery and will sell the imported supply to several distributors at prices ranging from $1.04 to $1.74 per million Btu depending on the extent of storage, vaporization and transportation service provided.[1/]

1/ On November 17, 1972, Distrigas applied for authority to import an additional 45 billion cubic feet of LNG annually from Algeria at a price of 73.9¢ per million Btu, plus escalations and adjustments.

The FPC approved the Distrigas project on March 9, 1972.[1/] In that decision, the Commission held -- on a first jurisdictional question -- that LNG is natural gas and subject to its jurisdiction in the same manner as other natural gas. On a second question respecting the scope of its jurisdiction, a majority of the Commission concluded that it had authority over the importation of the Distrigas supply and over its transportation and sale for resale in interstate commerce. At the same time, however, the Majority concluded that Distrigas' facilities to receive, store and regasify the LNG -- and the transportation and sale of LNG in the states of importation -- were not in interstate commerce and, hence, were outside its jurisdiction.

The last conclusion was the subject of disagreement among the members of the Commission at that time. The Majority (Commissioners Carver, Brooke and Walker)[2/] conceded that it could have taken jurisdiction over all of Distrigas' operations at the point of receipt of the LNG into the United States (i.e., the ship's flange) as a condition to approving importation under Section 3. However, the Majority chose not to do so because of a desire to encourage the development of new and supplemental sources of natural gas, including the importation of foreign LNG, at least so long as these supplemental sources remain competitive with other available supplies of gas or alternative fossil fuels. As the Majority explained:

1/ FPC Opinion 613, issued March 9, 1972 in re Distrigas Corp. (CP70-196).

2/ Commissioners Carver and Walker both resigned from the FPC later in 1972. Therefore, with new appointments, the Majority position of the Commission on this matter may change.

> "We are, in effect, inviting venture capital into the development of LNG import projects and, to the extent that these projects are intrastate in nature, we are expressing our intention not to regulate them. We are firmly of the opinion that the exemption of these projects from the federal regulatory umbrella will make them more attractive to private investors and lead to more gas at a lower price to the consumer, and effect this result sooner, than if we controlled every detail and decision related thereto." (FPC Opinion No. 613, Mimeo, p. 11.)

The two dissenting Commissioners (Chairman Nassikas and Commissioner Moody) took an opposite view. Both contended that the FPC should exercise comprehensive jurisdiction over LNG importation projects, including the transportation, sale and price of the delivered LNG whether or not sold in interstate commerce or for resale. It was further argued that the Majority's decision created a "regulatory gap" and in effect sanctioned a "what the traffic will bear" approach to LNG prices, thereby ignoring both the impact on domestic gas supplies and the need to protect ultimate consumers. As Chairman Nassikas put it: "When the price and volume of imported LNG have such a direct impact on the price, volume, and exploration activity for domestic gas, this Commission, as a resource allocating agency, must exercise its authority over alternative gas supplies."

A further contention of the FPC Chairman was that the regulatory gap created by the majority placed an impossible burden on state regulatory commissions and could encourage the emergence of a "vast network" of unregulated intrastate distributors of LNG along the Atlantic Seaboard, contrary to the public interest in securing commitment of gas supplies to jurisdictional markets.

The divided decision of the FPC in the Distrigas case reflects both differing legal rationale and differing policy conclusions which could have an impact on the encouragement of imported LNG supplies for U.S. markets. These differences will be resolved by the courts. The Commission decision is now pending before the Court of Appeals for the D.C. Circuit on an appeal brought by the Public Service Commission of New York. However, in appraising the future of LNG imports from the point of view of FPC regulation, the questions raised by the Distrigas case have been largely transcended by the Commission's later actions in the El Paso Algeria case, described below.

(b) El Paso Algeria Project

The second major LNG project considered by the FPC in 1972 involves the importation of one billion cubic feet per day from Algeria by subsidiaries of three major interstate pipeline companies -- Columbia Gas Transmission Co., Consolidated Gas Supply Corp. and Southern Natural Gas Co. The project was put together by El Paso Natural Gas Co. which formed a new company -- El Paso Algeria Corp. -- to buy LNG from Sonatrach and arrange for its transportation to the East Coast of the United States. The three importing pipelines will use the LNG for base load purposes, i.e., to augment supplies available from other sources to meet system requirements the year around. Assuming the project is still viable after court litigation, Columbia and Consolidated will import aggregate volumes of 650,000 Mcf/d at a terminal to be constructed on the Chesapeake Bay at Cove Point, Maryland and, after regasification, will transport the gas to

their market areas in Mid-Atlantic states. Southern Natural will import 350,000 Mcf/d at a terminal near Savannah, Georgia for delivery to its market areas primarily in the states of Georgia and Alabama. Deliveries are not expected to commence until late 1975 or 1976.

The El Paso Algeria project is substantially larger than the Distrigas project -- primarily as a result of the fact that the three importing pipelines seek the LNG as a base load supply on a year-round basis, as opposed to merely season heating supply to be furnished by Distrigas. The size difference is manifested in several ways: (1) the El Paso Algeria import volumes are 365 billion cubic feet a year compared with Distrigas volumes of approximately 15 billion per year; (2) the construction expenditures involved in the El Paso Algeria project total more than $1.6 million -- including expenditures of $628 million by Sonatrach for liquefaction and other facilities in Algeria, $742 million by El Paso Algeria for tanker construction and $270 million by the three importing pipelines for terminal, storage, regasification and pipeline facilities in the United States -- compared with an estimated $20 million outlay for the Distrigas project; and (3) effectuation of the El Paso project requires nine tankers (three of which are on order from a French yard and the remaining six, under present plans, are to be built in U.S. shipyards with subsidies from the Maritime Administration) compared with only one tanker required by the Distrigas project. Another major difference is that most of the LNG involved in the El Paso Algeria project is destined for sale in interstate commerce for resale, while much of the Distrigas supply will be consumed in the states of importation.

Despite these differences, the two projects raise similar questions respecting the reach of FPC jurisdiction, the cost of foreign LNG in relation to domestic supplies, reliance on foreign sources of supply, and means of encouraging supplemental non-conventional supply projects.

In an essentially unanimous decision issued June 28, 1972,[1/] the FPC authorized the El Paso Algeria project -- but subject to several unexpected and controversial conditions. Five conditions are of particular significance:

(1) The FPC directed that the three importing pipelines sell the LNG to their customers at incremental rates instead of at rolled-in rates, as proposed. (Incremental rates are based on the cost of the incremental source of supply alone -- which, in this case, is higher than the cost of the pipelines' other supplies -- while rolled-in rates reflect an averaging of the costs of all supplies.) The Commission reasoned that "rolled-in" pricing of the more expensive LNG would disguise its true economic cost. Moreover, to assure that incremental LNG prices would be passed through to ultimate consumers, the FPC prohibited the three importing pipelines from selling to distributors which did not have separate rate schedules for reselling the LNG at incremental rates.

(2) The FPC ordered El Paso Algeria to obtain a certificate under Section 7(c) of the Natural Gas Act to sell LNG to the three importing

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1/ FPC Opinion No. 622, issued June 28, 1972 in re Columbia LNG Corp. et al. (CP71-68 et al.).

companies.[1/] In a reversal of its position respecting the status of Distrigas, the Commission found El Paso Algeria to be engaged in the sale of LNG in interstate commerce for resale and hence a natural gas company subject to its jurisdiction. Again, unlike Distrigas, the Commission concluded that the terminal facilities proposed by the pipeline importing companies at Cove Point and Savannah were subject to its jurisdiction and required certification. (The status of these facilities was not contested in this case, since the pipelines applied for certification.)

(3) The FPC imposed a fixed limit on the import prices to be paid to El Paso Algeria -- 77¢ per million Btu for LNG delivered to Cove Point, and 83¢ per million Btu for deliveries to Savannah (plus, in each case, a 1¢ escalation in 1980). By this condition, the Commission prohibited the operation of cost escalation provisions in El Paso Algeria's contracts designed to protect it against inflationary cost increases over the contract terms. The FPC set the price ceilings at the level of estimated delivered LNG costs in the first full year of deliveries, and said indefinite escalation in costs to consumers should not be permitted.

(4) The FPC specified that if, at any time more attractive supply sources for the interstate market become available, "the terms upon which the imported LNG will be authorized for the interstate market may be adjusted accordingly."

1/ The decision was not unanimous on this ruling, one Commissioner dissenting and another concurring only with reluctance.

(5) The FPC outlawed provisions for the recovery of project costs by the three importing pipelines in the event of an interruption in the LNG supply.

These conditions were not only denounced by all the participants in the El Paso Algeria project, but they also evoked a considerable outcry from many other companies and interests.[1/] It was widely argued that one or more of the conditions would kill this project as well as jeopardize other high cost supplemental supply proposals. With very few exceptions, pipelines and distributors agreed that incremental pricing of individual sources of supply would create overwhelming administrative and practical problems, particularly for distributors, and hence would be unworkable. The Commission's conclusion that El Paso Algeria was a jurisdictional natural gas company was attacked as legal error (the argument being that El Paso Algeria is engaged in the sale of gas in foreign commerce for resale in interstate commerce, not in the sale of gas in interstate commerce for resale). Conditions restricting import prices to fixed levels and prohibiting pipeline recovery of project costs in the event of a supply interruption were condemned from many sides as totally unacceptable. Moreover, these conditions, coupled with the possible adjustment of project prices and other terms by the FPC at some future date if cheaper alternative

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1/ Because of the precedent-setting nature of Opinion No. 622, a large number of companies or groups not previously parties to the proceeding -- including gas pipeline and gas distributor associations, several individual pipelines and distributors, Interior Department, Maritime Administration, AFL-CIO, National Association of Regulatory Utility Commissioners, and others -- asked to intervene and filed petitions for rehearing.

supplies became available, were said to render project risks so great and project costs so uncertain as to preclude financing.

Faced with such overwhelming opposition, the FPC modified its decision on October 5, 1972 (Opinion No. 622-A) so as to delete or substantially revise most of the contested conditions. The modifications were conceded to be necessary to assure financing of the project. Specifically, the Commission (1) retained the requirement that the importing pipelines sell LNG on an incremental rate basis, but eliminated the further condition in effect requiring distributor customers to sell also on that basis; (2) reversed its jurisdictional holding respecting El Paso Algeria, concluding on reconsideration that the company's operations would be wholly in foreign commerce and hence outside FPC jurisdiction; (3) retained the fixed import ceilings, but indicated price adjustments would be allowed for additional costs shown to be justified; (4) clarified that language referring to the possible adjustment of imported LNG terms, if cheaper alternative supplies become available, did not indicate an intent to alter the terms of the instant project but was meant to apply to consideration of future projects; and (5) relaxed the prohibition against pipeline recovery of project costs in the event of a supply interruption so as to permit the recovery of out-of-pocket expenses but no depreciation or return on equity capital.

The above-described decisions illustrate the FPC's dilemma in approving high-priced supplemental gas supply projects badly needed to augment domestic gas supplies which have declined because of too low wellhead prices allowed by regulation in the past, among other reasons. With

the conditions originally imposed in Opinion No. 622, the Commission was obviously seeking to hold the lid on supplemental project costs and prices to the extent possible. These conditions, however, were considerably more onerous than any ever imposed on a domestic supply project. Given this fact, together with the risks and uncertainties inherent in the El Paso Algeria project, the project would have collapsed if the original conditions had been retained, according to the applicants.[1/]

To the extent Opinion Nos. 622 and 622-A can be considered a regulatory precedent, their most significant impact for the future of supplemental supply projects lies in the adoption of incremental pricing principles.[2/] Essentially, the arguments in favor of this approach are: (1) an incremental supply of gas which cannot be sold at its full cost is economically indefensible; (2) rolled-in pricing of high cost supplies will merely permit the continued use of gas for low priority uses and hence a continued misallocation of energy resources through distorted prices; and (3) incremental pricing will permit distributor customers of pipelines to

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1/ The El Paso Algeria case is not yet over. Appeals have been filed in the courts by all of the project participants, as well as by environmental groups which contest the location of the proposed LNG terminal site at Cove Point, Maryland. These groups, however, recently agreed to drop their opposition to the Cove Point terminal subject to the laying of pipelines from the ship's docking platform to shore in an underwater tunnel, as well as certain land use changes.

2/ In Opinion No. 622-A, Commissioner Brooke dissented to the retention of incremental pricing for pipelines, and Chairman Nassikas concurred only for the purpose of certificating the project without further delay. More important in terms of court review, the incremental approach was promulgated in the El Paso Algeria case in the absence of any record evidence on the subject.

evaluate whether other alternatives for meeting system needs are more economical.

On the other hand, the entire pattern of gas sales throughout the country is predicated on rolled-in pricing. New supplies are typically acquired by pipelines on a systemwide basis to serve all markets. Over the years, this has resulted in efficient use of capacity and avoided complex problems of allocating particular supplies to particular customers. Furthermore, in the El Paso Algeria case, the supply involved will not be directed to expand existing markets or attach new loads but rather is required to maintain existing service to present customers. Under these conditions, the economic rationale for incremental pricing is questionable.

It is assumed that the FPC will give substantial study to the incremental pricing issue in the future.

Further discussion of incremental pricing appears in Chapter V (pages V-62 through V-66).

I. Synthetic Gas

FPC regulation of synthetic gas (SNG), alternatively called substitute natural gas or substitute pipeline gas, raises essentially the same issues as base load LNG importation. The chief questions include: the extent of FPC jurisdiction, the source and cost of the feedstock supply, the cost of the final gas product, and incremental versus rolled-in pricing of SNG sales by pipelines.

A sizeable number of SNG projects (some 40 or more) based on reforming of naphtha or lighter liquid hydrocarbons, or on refining of crude oil into naphtha (for subsequent gasification) and low sulfur residual

fuel oil, have been announced in the past 18 months. Some of these are wholly intrastate and so may proceed without application to the FPC. Thus far, five proposals have been filed with the Commission, hearings have been held on three, and one has been authorized by the FPC.

In addition, an application was filed in November 1972 in the FPC by El Paso Natural Gas Co. for authority to construct facilities to connect synthetic gas to be produced by a coal gasification plant which El Paso proposes to build in northwestern New Mexico.

The five liquid gasification projects filed with the FPC are as follows:

(1) Columbia LNG Corp. proposes to reform 250,000 Mcf/d from imported Canadian light hydrocarbon liquids (principally, ethane and propane) at a $32 million plant to be built near Green Springs, Ohio. The company's application to the Commission did not seek authority to construct the plant but only to sell SNG at the plant tailgate to its parent, Columbia Gas Transmission Co., at an estimated cost of service rate of $1.12/Mcf. Hearings were held in October 1971. Columbia originally expected to have the plant in operation by mid-1973; however, delays have occurred because of failure of Columbia's feedstock supplier to receive the necessary Canadian authorizations for export of ethane. Columbia is now revising the project to use only propane as feedstock, and further hearings before the FPC are likely.

(2) Algonquin SNG Inc. has requested FPC authority to construct a $40 million plant near Freetown, Massachusetts to produce a maximum of 120,000 Mcf/d for sale to Algonquin Gas Transmission Co., with initial output of 57,336 Mcf/d. The feedstock for the initial volumes would be

domestic naphtha purchased from Humble Oil & Refining Co. f.o.b. its Bayway, New Jersey refinery at 10.5¢ per gallon (plus escalations), equivalent to $3.417 per barrel. At full plant output of 120,000 Mcf/d, the estimated cost of service rate to Algonquin Gas Transmission is $1.41/Mcf assuming year-round deliveries (335 days) and $1.80/Mcf assuming winter month deliveries only (151 days). On December 7, 1972, the FPC issued a decision[1/] disclaiming jurisdiction over the SNG plant but authorizing the receipt and resale of synthetic gas by Algonquin Gas Transmission.

(3) Tecon Gasification Corp. has applied for authority to construct a $140 million plant in order to produce 500,000 Mcf/d of SNG from foreign and domestic naphtha. The original plan proposed construction of the plant in South Plainfield, New Jersey as a joint venture of Texas Eastern Transmission Corp. and Consolidated Gas Supply Corp. Texas Eastern was to have supplied 60% and Consolidated 40% of the capital funds, with the final plant output to have been split in similar proportions. Several days of hearings were held on this project in the spring of 1972. Subsequently, the town council of South Plainfield voted to deny a permit for installation of the plant at South Plainfield. Tecon now seeks to build the plant at a site near Baton Rouge in Ascension Parish, Louisiana. The revised project would be sponsored solely by Texas Eastern. The naphtha feedstock would continue to be derived from foreign and domestic sources, including two-thirds of the total (about 104,000 barrels per day) from foreign suppliers.

1/ FPC Opinion No. 637, issued December 7, 1972 in re Algonquin SNG Corp. (CP72-35).

The estimated cost of SNG to Texas Eastern in the first full year of plant operation (1975 according to present plans) is $1.27/Mcf.

(4) Transco Energy Co. proposes to build an $85 million naphtha gasification plant near Chester, Pennsylvania in order to reform approximately 250,000 Mcf/d from domestic and foreign naphtha for sale to Transcontinental Gas Pipe Line Corp. Feedstock requirements for the plant are estimated at 53,500 barrels per day of naphtha (plus 4,200 barrels per day of propane for enrichment purposes) which is expected to cost $4.50 per barrel on average during the first three years of plant operation (1975-1977). The projected cost of SNG to Transcontinental Gas Pipe Line is $1.40/Mcf in 1975. While Transco Energy applied for a certificate to construct the plant, it has now asked the FPC to disclaim jurisdiction over the SNG facility.

(5) Coastal Energy Corp. proposes to build a $33 million plant near Corpus Christi, Texas in order to produce about 125,000 Mcf/d of SNG from primarily domestic liquid feedstocks for sale to Trunkline Gas Co. The proposed rate to Trunkline is $1.10/Mcf, subject to adjustment upward and downward according to changes in the wholesale price of domestic crude oil east-of-California. Trunkline has requested FPC authority to construct facilities to connect and purchase the SNG, and Coastal Energy has applied for a disclaimer of FPC jurisdiction over the proposed plant.

As noted, the above five proposals raise questions of jurisdiction, feedstock supply and cost, and method of pricing the high cost SNG supply. With respect to jurisdiction, Opinion No. 637 appears to have removed much of the uncertainty -- at least at the level of FPC decision

(which is always subject to reversal in the courts). The principal question concerned the extent of the FPC's jurisdiction over the reformer facilities and the sale of synthetic gas from such facilities. The Commission held that it had no jurisdiction here in light of language in the Natural Gas Act defining natural gas as "either natural gas unmixed or any mixture of natural and artificial gas." Thus, because synthetic gas is artificial gas and not natural gas, it is not jurisdictional. At the same time, the FPC made clear its authority over the interstate transportation and sale for resale of SNG once it is introduced into the system of an interstate pipeline company and becomes mixed with natural gas. This aspect of jurisdiction was never in dispute.

The FPC's disclaimer of jurisdiction is an important holding for companies planning SNG projects from the standpoint of depth of evidence and procedures required to obtain FPC approval. Any simplification here will undoubtedly tend to facilitate SNG projects. In a broader sense, however, the Commission's jurisdictional holding respecting the reformer facilities is not likely to significantly affect the volume of SNG supply entering interstate markets in view of the Commission's uncontroverted authority to deny or condition the transportation of SNG (when mixed with natural gas) and its sale for resale in interstate commerce.

In regard to feedstock, two of the five projects described above contemplate use of both foreign and domestic naphtha, one contemplates use of only domestic naphtha at least initially, one is based on domestic liquids (unspecified as to type) and the fifth would rely on imported LPG from Canada. Those projects based on use of foreign naphtha require import liquid

authorization from the Oil Import Administration which, to date, has granted no licenses for the import of naphtha for conversion to synthetic gas. Use of domestic naphtha avoids this problem, but it is presently more expensive than foreign supplies and also is not generally available today for uses other than the manufacture of gasoline and military jet fuel. As to LPGs, any widespread use of domestic supplies for gasification purposes would cause a considerable upward price effect in various markets, including the petrochemical market which, in the United States, largely depends on natural gas liquids for feedstock purposes. Canadian LPGs are not subject to U.S. import quotas but, as noted in connection with the Columbia LNG case, are subject to Canadian export restrictions.

In short, the question of feedstocks for SNG projects -- particularly those based on use of foreign liquids -- involves complex considerations which should be evaluated in the context of overall policy objectives, rather than in isolated fashion in proceedings before the FPC.

A further major regulatory difficulty is the cost of the SNG product. With respect to the five proposals submitted to the FPC, the projected unit costs range from $1.10 to $1.41/Mcf, or higher. With the exception of Algonquin Gas Transmission Co. which contemplates sale of the SNG under a separate rate schedule to buyers contracting for the service, all of the other pipeline purchasers propose to roll in the cost of the SNG with the cost of overall system supplies. On a rolled-in basis, the estimated cost impact of the SNG ranges from 5.9¢/Mcf in the case of Columbia Gas Transmission to 15.7¢ in the case of Texas Eastern Transmission.

Assuming the precedent established in the FPC Opinion No. 622 respecting LNG imports from El Paso Algeria, the FPC can be expected to require incremental pricing for SNG supplies. This will cause considerable marketing difficulties.

Except for feedstocks, the foregoing considerations also pertain to coal gasification projects. For example, the proposal recently filed by El Paso with the FPC involves an estimated SNG cost of $1.21 per Mcf which the pipeline proposes to pass on to customers through a purchased gas adjustment provision in its tariff. On this basis, the projected cost impact of the new supply to El Paso's customers would be 6¢/Mcf.

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CHAPTER V - REGULATORY MEANS OF INCREASING GAS SUPPLY

In discussing means by which natural gas supply might be increased through the regulatory process, it is necessary to distinguish between (1) domestic natural gas production in the Lower 48 States, (2) imported natural gas and (3) synthetic pipeline quality gas. The second category includes pipeline imports from Canada and Alaska, and LNG imports from overseas foreign nations. The third category includes the manufacture of synthetic gas from liquid hydrocarbon feedstocks (domestic or foreign) and from domestic coal.

In the case of domestic supply of natural gas produced in the Lower 48 States, the greatest hopes for turning around the present exploratory downtrend, and hence for improving supply, include permitting the wellhead price for interstate gas to be more responsive to the market forces of supply and demand, and accelerating and regularizing the leasing of offshore lands. These measures have broad support both inside and outside the gas producing industry, although there are some consumer interest groups which contend that no price increase beyond current levels should be permitted without a thorough government evaluation of producer reserves to ascertain whether and to what extent a shortage actually exists. Essentially, their view is that producers are holding back reserves from commitment to interstate markets -- or refusing to develop proven reserves -- in anticipation of higher prices. Once this anticipation is removed, the consumer groups suggest, greater volumes will be forthcoming to interstate markets. A basic problem with this position, however, is that the evidence to date

discloses no significant amount of uncommitted gas reserves available for sale by producers. While the principal source of proven gas reserves over the years is the American Gas Association (an industry association which compiles and publishes gas reserve data annually),[1/] trends in these reserves are corroborated by reports on dedicated gas supplies filed with the FPC each year by interstate pipelines. Moreover, reports on uncommitted reserves submitted by larger gas producers on various occasions in the past few years at the Commission's directive do not bear out the contention of a substantial "sitting on reserves." The most recent reports of this type showed a total of only 3.8 trillion cubic feet (excluding Alaska) available for sale at the end of 1971, amounting to only about 1.5% of the nation's estimated proved gas reserves on that date (again excluding Alaska).

A competitive market approach to wellhead regulation -- which will necessarily entail substantial price increases -- can be accomplished through legislative action to decontrol sales by producers either wholly or in part, or by a reorientation of the direction of FPC regulation. As explained in pages V-23 through V-29, the Commission has already taken steps to respond to the supply crisis, but more is needed.

1/ The FPC, together with the U.S. Geological Survey and technical experts from the U.S. Navy, is presently conducting an independent analysis of the nation's proved natural gas reserves. The results of this analysis are scheduled to be published at the end of May 1973. In addition, the Federal Trade Commission has been conducting an investigation of the reporting of gas reserve information by the American Gas Association since October 1970. No findings have been issued as yet.

At the very least, legislative action is necessary to reduce the uncertainty and time lags which dominated producer regulation throughout the 1960's. All segments of the gas industry, as well as regulators, both past and present, agree on the need to avoid the frequent -- and, in the eyes of the producers, totally arbitrary -- reductions applied by the FPC to producer prices in the past. Hearings were held before both House and Senate committees in the last session of Congress on so-called "sanctity of contract" bills which would assure certainty of price and other terms. While some consumer groups opposed the need for any such legislation at all (as indicated on page V-30), most of the criticism during the hearings was directed to certain provisions of these bills, but not to the principle of "contract sanctity" itself. However, the bills were not even reported out of the committees and never came to a vote. Reactivation and passage of this legislation in essentially similar form would appear to be a minimum step toward ameliorating the domestic supply situation. The sanctity of contract step, however, is unlikely to prove effective unless coupled with FPC action to increase producer prices to more realistic market levels.

There is now growing opinion, however, that sanctity of contract legislation would not go far enough in providing the needed turnaround in domestic supplies and that deregulation of producer sales, at least new gas sales, is necessary. The petroleum industry supports this course, and so do an increasing number of government officials. Decontrol offers substantial hope for raising domestic supply, but it also raises some substantial problems. As noted on pages V-34 through V-37 not the least

of these problems is that no one can predict with any degree of certainty what the supply response will be. Moreover, Congressional passage of any decontrol measure is problematical.

On the other hand, there are those who advocate the view that the present shortage of gas necessitates an expansion rather than a relaxation of FPC regulation. Proposals have been advanced, for example, to extend the Commission's jurisdiction to intrastate sales and direct sales, and to establish end-use controls on a nationwide basis. If the supply of gas available for interstate markets does not improve and new reserves are largely committed to nonjurisdictional and largely industrial uses, the pressures for end-use rationing by the FPC or some other regulatory authority will undoubtedly increase. A basic difficulty with such proposals is that they are directed to coping with the crisis as it gets worse rather than to attacking its cause.

With respect to imported gas supply and synthetic gas supply, multiple policy problems are involved. Among them are balance of payments questions, national security, and interrelationships with other fuels. Also to be considered are the more traditional certificate criteria of need, adequacy and reliability of supply, economic justification, and financeability. There is an obvious need to formulate regulatory policies at the earliest possible date to encourage development of supplemental gas projects meeting national interest and economic feasibility criteria. At the same time, it should be noted that gas imports and synthetic gas production will not be available in any important degree to augment domestic sources until the latter part of this decade or the

early 1980's. Nevertheless, the criteria and policies laid down in the next year or so will be instrumental in influencing future development.

It should also be emphasized that none of the more likely means for increasing gas supply will result in any substantial expansion of supply overnight. With respect to domestic gas, even if legislation removing or relaxing part of the FPC's regulatory powers were passed within the next year -- a highly speculative event at best, the result would take some time to perceive because of the time lag between exploration for new reserves and the date production commences to flow to markets. This lag is variously estimated at between three to seven years depending upon the producing area and distance from established market outlets. Similarly, measures taken by the FPC to increase supply are also subject to the time lag problem and, in addition, will undoubtedly continue to face opposition from certain quarters, which opposition generally entails court litigation and the delays associated therewith.

Nor do supplemental sources of gas supply offer much hope of supply alleviation for the immediate future. An exception could be the reforming of gas from naphtha and other light hydrocarbon feedstocks. Reforming plants can be built within a period of two years or less. Hence, relaxation of import controls respecting naphtha feedstock supplies -- coupled with expedited FPC review of and favorable action on reformer gas projects -- is perhaps the measure most capable of stimulating a noticeable increment of supply in the short term. However, the importation of naphtha is enmeshed in complex questions concerning interfuel relationships and the direction of the nation's overall import policies in the years ahead.

Possible regulatory strategies for increasing supply are discussed in greater detail in the following pages, together with some suggestions as to the role which EPA might pursue. First, however, some background information is reviewed in order to lend perspective to the problems involved.

A. Supply-Demand Picture: Background Data

In considering regulatory strategies for the future, an understanding of some past trends and current relationships is necessary to appreciate the extent of the corrective measures needed to reverse the present situation and to accomplish any significant increase in supply.

The following portrays indicators of the declining trend in gas exploratory efforts and in gas reserve additions in the United States; trends in natural gas prices related to interstate-intrastate levels, competitive fuels and inflation; the extent of the supply-demand imbalance projected by two sources in the years ahead; and the magnitude (and location) of estimated reserves which might contribute to overcoming the supply imbalance.

1. Trends in Gas Exploration and Reserves

The story of the decline in gas well drilling and other exploratory activity, increase in depth of wells drilled and increase in cost of wells drilled over the past decade and longer is by now familiar to all concerned with energy matters, especially natural gas matters. Also well known is the declining trend in proved gas reserves in the Lower 48 States relative to production (R/P ratio), and the absolute decline in proved

reserves in the last four years due to reserve additions insufficient to offset production.

Nevertheless, to lend perspective to the overall picture, certain trends warrant reiteration.

First, as shown on Table V-1, annual production in the Lower 48 States[1/] has approximately doubled in the last 14 years. The total increase in production over the 1958-1971 period was 92%, representing an average annual growth rate of 5.1% through 1970 (and only 0.5% between 1970 and 1971). By contrast, proved gas reserves in the Lower 48 reached a peak in 1967 only 14% above the 1958 level and by 1971 were 2% below the 1958 level. Moreover, during the past four years, while production continued to climb (from 19.3 trillion cubic feet in 1968 to 21.9 trillion in 1971, or over 13%), total proved reserves dropped from 289.3 trillion cubic feet at the beginning of 1968 to 247.4 trillion at the end of 1971, or nearly 15%. As a result of these divergent trends in production and reserves, the R/P ratio fell from 22.1 in 1958 to 11.3 in 1971.[2/]

The drop in proved reserves after 1967 reflects the fact that reserves added in the Lower 48 were insufficient to offset production --

1/ The reserve and production data described in this section relate to the Lower 48 States, thereby excluding Alaska. The exclusion of Alaska reflects the fact that Alaskan gas is presently not available to markets in the Lower 48 States and can be made available only via pipeline transportation through Canada or in liquefied form by tanker. Until such transportation comes about, Alaska is considered as a separate consuming and producing area.

2/ The R/P ratio is a mere mathematical calculation of the times by which proved reserves exceed annual production. While sometimes expressed in terms of years, this ratio does not indicate the actual number of years proved reserves can sustain a given production level since reserves are subject to declining deliverability characteristics with depletion of reservoirs and consequently cannot all be produced.

TRENDS IN GAS RESERVES AND PRODUCTION
UNITED STATES EXCLUDING ALASKA
1958 - 1971

(All Volumes at 14.73 Psia)

Year	Total Reserves Additions Tcf	Total Reserves Additions Index 1958-1959=100	Production Tcf	Production Index 1958=100	Finding-Production Ratio	Year-End Proved Reserves[a] Tcf	Year-End Proved Reserves[a] Index 1958=100	Reserve-Production Ratio	Year-End Reserves Dedicated to Interstate Pipelines Tcf	Year-End Reserves Dedicated to Interstate Pipelines Percent Total Reserves
1958	18.9)	100	11.4	100	1.65	252.8	100	22.1	n.a.	n.a.
1959	20.6)		12.4	109	1.67	261.1	103	21.1	n.a.	n.a.
1960	13.8)	85	13.0	114	1.06	262.2	104	20.1	n.a.	n.a.
1961	16.4)		13.4	118	1.22	265.4	105	19.8	n.a.	n.a.
1962	18.8)		13.6	119	1.38	270.6	107	19.9	n.a.	n.a.
1963	18.1)		14.5	127	1.25	274.5	109	18.9	188.5	69
1964	20.1)	103	15.3	134	1.31	279.4	111	18.2	189.2	68
1965	21.2)		16.2	142	1.30	284.5	113	17.5	192.1	68
1966	19.2)		17.5	154	1.10	286.4	113	16.4	195.1	68
1967	21.1)		18.4	161	1.15	289.3	114	15.8	198.1	68
1968	12.0)	52	19.3	169	0.62	282.1	112	14.6	195.0	69
1969	8.3)		20.6	181	0.40	269.9	107	13.1	187.6	70
1970	11.1)		21.8	191	0.51	259.6	103	11.9	173.6	67
1971	9.4)		21.9	192	0.43	247.4	98	11.3	161.3	65

n.a. - Not available.

a/ Includes reserves held in underground storage, which increased from 1.7 Tcf at the end of 1958 to 4.3 Tcf at the end of 1971.

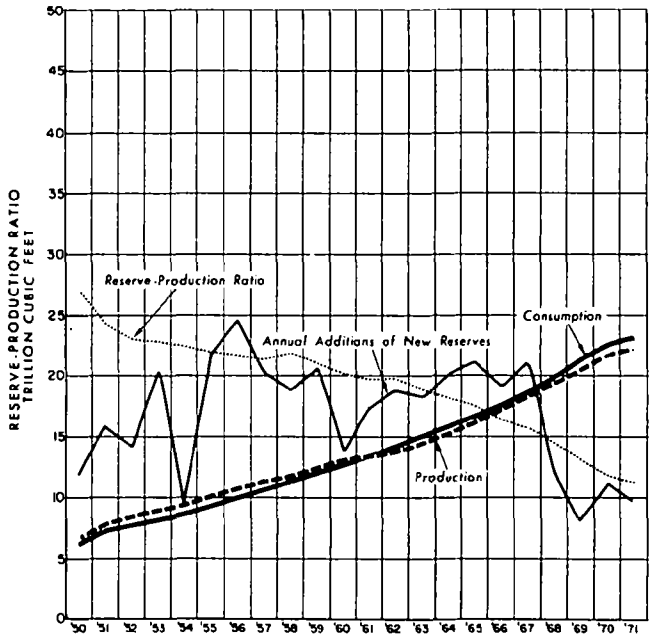
Source: American Gas Association Committee on Natural Gas Reserves; FPC, Gas Supplies of Interstate Pipeline Companies, 1970 and Press Release No. 18513.

Table V-1

in fact, reserve additions averaged only about 50% of production over the 1968-1971 period. Moreover, while reserve additions reflect an erratic pattern from year to year as a result of the uncertainty of drilling results and revisions of previous estimates, it is significant that the level of reserves added in the last four years -- averaging 10.2 trillion cubic feet -- were barely more than 50% of the average level of additions in the previous 10 years.

The trends in reserves, reserve additions and production are portrayed graphically below.

RESERVE—PRODUCTION RATIOS, ANNUAL ADDITIONS OF NEW RESERVES, PRODUCTION, AND CONSUMPTION OF NATURAL GAS IN THE UNITED STATES (EXCLUDING ALASKA)



The reason for the decline in reserve-production and finding-production trends is the sharp drop in gas well drilling which has occurred over the past decade. As shown in Table V-2, the number of successful exploratory gas well completions reached a peak in 1959 and has declined

TRENDS IN GAS WELL DRILLING
UNITED STATES EXCLUDING ALASKA

1958 - 1971

Year	New Field Wildcats		Successful Exploratory Wells		Successful Developmental Wells		Average Depth of Gas Wells		Average Cost Per Gas Well Foot Drilled	
	Number of Wells	Index 1958=100	Number of Wells	Index 1958=100	Number of Wells	Index 1958=100	Feet	Index 1958=100	$/Ft.	Index 1958=100
1958	268	100	822	100	4,207	100				
1959	305	114	909	111	3,958	94	5,462	100	$18.42	100
1960	296	110	866	105	4,280	102	5,523	101	18.55	101
1961	314	117	808	98	4,674	111	5,362	98	17.60	96
1962	315	118	769	94	4,580	109	5,362	98	17.98	98
1963	240	90	663	81	3,902	93	5,373	98	17.11	93
1964	250	93	575	70	4,116	98	5,638	103	18.10	98
1965	233	87	513	62	3,959	94	5,548	102	18.16	99
1966	229	85	574	70	3,743	89	6,149	113	21.60	117
1967	178	66	553	67	3,045	72	6,110	112	22.90	124
1968	125	47	429	52	2,892	69	6,173	113	23.69	129
1969	191	71	616	75	3,021	72	6,021	110	24.35	132
1970	183	68	480	58	2,742	65	6,007	110	26.62	145
1971	202	75	437	53	2,961	70	n.a.	n.a.	n.a.	n.a.

n.a. - Not available.

Source: New Field Wildcats and Successful Exploratory Wells - American Association of Petroleum Geologists.
Successful Developmental Wells - American Association of Petroleum Geologists and World Oil.
Average Gas Well Depth and Average Cost of Drilling - Joint Association Survey of the U. S. Oil and Gas Producing Industry.

Table V-2

EXPLORATION INDICATORS
UNITED STATES
1958 - 1971

Year	Geophysical Crew Time: Number of Months	Geophysical Crew Time: Index 1958=100	Rotary Rigs in Operation: Average Number of Rigs	Rotary Rigs in Operation: Index 1958=100
1958	5,731	100	1,923	100
1959	5,696	99	2,074	108
1960	5,207	91	1,750	91
1961	5,024	88	1,760	92
1962	4,231	74	1,636	85
1963	4,174	73	1,501	78
1964	4,406	77	1,502	78
1965	4,471	78	1,387	72
1966	3,835	67	1,273	66
1967	3,496	61	1,134	59
1968	3,390	59	1,150	60
1969	3,259	57	1,194	62
1970	2,521	44	1,028	53
1971	n.a.	n.a.	975	51

n.a. - Not available.

Source: Geophysical Crew Time - Society of Exploratory Geophysicists.
Rotary Rigs - Hughes Tool Co.

by over 50% since that time, while successful gas developmental wells have fallen by about 37% since the 1961 peak year. New field wildcats reflect a similar decline.

Exploratory activity as measured by geophysical prospecting and by the number of rotary rigs in operation has also been in a long-term decline, as shown in Table V-3.

2. Trends in Gas Prices

The tables on the following pages illustrate, first, that average wellhead prices of natural gas, when expressed in dollars of constant purchasing power, have hardly risen over the past 14 years and, in fact, have declined by about 10% since 1964. (Table V-4) Second, the data reveal the price of natural gas is significantly lower than substitutable fuels both at the wellhead and at the point of consumption for residential use. (Tables V-4 and V-5) Third, the data reflect a substantial disparity between wellhead prices for gas sold interstate and gas sold intrastate. (Table V-6) At the present time, this disparity is undoubtedly greater than in more plentiful supply years when interstate prices constituted a brake on prices contracted in the intrastate market. This situation no longer pertains, as indicated by recently negotiated prices for spot intrastate sales up to 52¢ in Oklahoma, 60¢ in Louisiana and 73¢ in Ohio. Obviously, a readjustment of interstate-intrastate price relationships is necessary if interstate markets are to compete for new supplies. One step toward such readjustment -- albeit of a temporary, not permanent, nature -- is the FPC's routine approval of limited-term emergency sales in interstate commerce over the past year at prices up to 35¢/Mcf. Also,

TRENDS IN WELLHEAD PRICES OF NATURAL GAS AND
COMPARISON WITH OTHER HYDROCARBON FUEL PRICES
AT POINTS OF PRODUCTION
UNITED STATES

1958 - 1971

Year	Average Wellhead Prices of Natural Gas		Comparative Prices of Hydrocarbon Fuels At Points of Production				
	In Current Dollars	In Constant (1967) Dollars a/	Natural Gas	Crude Oil	Coal	Gas Price As Percent of Crude Oil	Gas Price As Percent of Coal
	(Cents Per Mcf at 14.73 Psia)		(Cents Per MMBtu)				
1958	12.0	13.9	10.8	52.1	18.7	21%	58%
1959	13.0	14.9	11.7	51.0	18.6	23	63
1960	14.1	15.9	12.7	50.6	18.3	26	69
1961	15.1	16.9	13.6	49.8	17.9	27	76
1962	15.5	17.1	14.0	50.2	17.5	28	80
1963	15.9	17.3	14.3	50.6	17.2	28	83
1964	15.4 b/	16.6 b/	13.9 b/	51.1	17.4	27	80
1965	15.6	16.5	14.1	51.2	17.5	28	81
1966	15.7	16.2	14.2	51.6	17.9	28	79
1967	16.0	16.0	14.4	51.8	18.4	28	78
1968	16.4	15.7	14.7	52.7	18.6	28	79
1969	16.7	15.2	15.1	55.2	20.0	27	76
1970	17.1	14.7	15.5	56.5	25.5	27	61
1971	18.2	15.0	16.5	60.2	29.0	27	57

a/ Prices in current dollars deflated by the B.L.S. Consumer Price Index.

b/ Excludes all taxes beginning in 1964. In 1964 taxes excluded amounted to 2.06 percent of the reported wellhead value.

Source: U. S. Bureau of Mines.

TREND IN PRICES OF GAS AND FUEL OIL
FOR RESIDENTIAL HEATING
UNITED STATES

1959 - 1971

Year	Gas	Fuel Oil #2	Gas As Percent of Fuel Oil
	--(Cents Per MMBtu)--		
1958	n.a.	108.7	n.a.
1959	67.2	110.2	61%
1960	72.4	108.3	67
1961	72.8	112.6	65
1962	71.9	112.6	64
1963	71.9	115.1	62
1964	81.8	113.3	72
1965	81.6	115.7	71
1966	83.4	118.5	70
1967	83.0	121.9	68
1968	83.9	125.7	67
1969	85.1	128.5	66
1970	89.2	133.2	67
1971	95.7	141.5	68

n.a. - Not available.

Source: Bureau of Labor Statistics, Retail Prices and Indexes of Fuels and Utilities; heat value employed for fuel oil is 5,825,000 Btu per barrel.

CURRENT RATES FOR INTERSTATE AND INTRASTATE
SALES OF NEW GAS

Producing Area	Pressure Base (Psia)	Interstate Sales[a]	Intrastate Sales[b]
		------(Cents Per Mcf)-------	
South Louisiana	15.025	26.0	22.0-35.0
Permian Basin	14.65	25.5	14.0-49.0
Texas Gulf Coast	14.65	24.0	17.0-45.4
Hugoton-Anadarko	14.65	20.0-21.5	14.0-40.0
Other Southwest	14.65	22.5-25.4	10.3-48.5
Rocky Mountain	15.025	22.5-24.0	15.0-43.1
Appalachian Basin	15.025	32.0-34.0	46.0-53.8[c]
California	14.73	--	30.0-37.0

a/ Excluding tax, gathering and Btu adjustments.

b/ Including tax reimbursement and adjustments for gathering and Btu.

c/ Primarily Michigan.

Source: Rates for interstate sales from FPC Opinion Nos. 468, 586, 595, 598 and 607; FPC Order Nos. 411 and 435; and FPC Staff recommendation in Docket No. AR70-1.

Rates for intrastate sales from FPC report of 11/14/72 in Docket No. 389-A.

some contracts for interstate sales from South Louisiana have recently been signed at 45¢ under the optional procedure.

3. Extent of Gas Shortage

Projections of the gas supply imbalance have been made by the FPC Staff and by the National Petroleum Council, among others. These projections, shown in Tables V-7 and V-8, should be viewed as order-of-magnitude estimates, not as precise forecasts of future supply in relation to demand.

In a report issued in February 1972,[1/] the FPC Staff estimated a total gas supply deficiency -- or unsatisfied demand -- rising from 0.9 trillion cubic feet in 1971[2/] to 3.6 trillion in 1975, 9.5 trillion cubic feet in 1980 and 13.7 trillion in 1985. On the demand side, these projections adopted the estimates of the Future Requirements Committee (with certain adjustments), reflecting an annual rate of increase of about 3.9%, 1970-1985. On the supply side, the Staff assumed a gradual increase in the present annual level of gas reserve additions (11.1 trillion cubic feet in 1970 and 9.4 trillion in 1971) to the 1961-1970 average level (17 trillion cubic feet) by 1976, and continuing at that level each year thereafter through 1990. Annual production was estimated on an area-by-area basis, taking into account past drilling trends, area potential for

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1/ National Gas Supply and Demand, 1971-1990, FPC Staff Report No. 2, February 1972.

2/ That demand went unsatisfied in 1971 is evident from interstate pipeline curtailments reported to the FPC of nearly 350 billion cubic feet, coupled with restrictions on attachments of new and increased sales loads by many pipelines and distributors throughout the nation. (FPC Press Release dated November 27, 1972.)

sustained contribution to national supply, and productive capability of supply sources at different stages of depletion.

The Staff projections assumed existing levels of regulated prices (i.e., prices in effect or approved at the beginning of 1972). At these prices -- including increased rates allowed by the FPC during the previous year for several supply areas, Staff considered an increase in reserve additions from approximately 10 trillion cubic feet in 1970-1971 to 17 trillion by 1976 as likely. At the same time, Staff indicated that annual reserve additions could be higher than forecast if the industry were to find the regulatory atmosphere more conducive to increased exploratory and developmental efforts.[1/]

1/ The Staff report acknowledged the imprecision inherent in its forecast, or any forecast of supply responsiveness to price. Specifically, Staff explained:

> "Our construction of a national supply-demand balance necessarily involves a quantitative estimate of the level of future reserve additions. Being unable to quantify the increments of additional reserve additions which may result from specific increases in gas prices and other recent Commission incentives to increase findings, we were required to place considerable reliance upon past trends. However, if the producing industry finds the present regulatory atmosphere more conducive to increased exploratory and developmental efforts, such past trends may lose some of their prognostic value. If this occurs, our prediction as to annual additions to reserves may prove to be understated. When we establish a schedule of additions of reserves, we in effect make a projection which the Commission correctly found could not be made based on a precise quantification of the future supply response to price. This should not be taken as a defect in our analysis. Our purpose here is to approximate a likely supply-demand balance over the period considered and to establish, at least in our view, the order of magnitude of the various balance components so that some ideas of the probable supply-demand posture of the Nation might be generated along with some notion of the sensitivity of the balance to modification through changes in the relative contributions of the various elements." (Staff Report, page 6)

U. S. (EXCLUDING ALASKA) GAS SUPPLY GAP
AS PROJECTED BY FPC STAFF

(All Volumes in Trillions of Cubic Feet at 14.73 Psia)

Year	Annual Demand	Domestic Production (Lower 48)	Net Pipeline Imports	LNG Imports	Gas From Coal	Gas From Alaska	Gas From Liquid Hydrocarbon	Total Supply	Unsatisfied Demand	Percent Demand Unsatisfied
Actual Data										
1970	22.6	21.8	0.8	--	--	--	--	22.6	--	--
1971	22.8	21.9	0.9	--	--	--	--	22.8	--	--
Projections										
1971	24.6	22.8	0.9	--	--	--	--	23.7	0.9	3.6%
1972	26.1	23.8	1.0	--	--	--	a/	24.8	1.3	5.0
1973	27.7	24.7	1.1	--	--	--	a/	25.8	1.9	6.9
1974	28.8	24.8	1.1	--	--	--	a/	25.9	2.9	10.1
1975	29.8	24.7	1.2	0.3	--	--	a/	26.2	3.6	12.1
1980	34.5	20.4	1.6	2.0	0.3	0.7	a/	25.0	9.5	27.5
1985	39.8	18.5	1.9	3.0	1.4	1.3	a/	26.1	13.7	34.4

a/ Data considered insufficient for quantitative projection.

Source: FPC, National Gas Supply and Demand, 1971-1990, Staff Report No. 2, February 1972, Table 1.

Table V-7

U. S. (EXCLUDING ALASKA) GAS SUPPLY GAP
AS PROJECTED BY NATIONAL PETROLEUM COUNCIL

(All Volumes in Trillions of Cubic Feet at 14.73 Psia)

Year	Annual Demand	Domestic Production (Lower 48)	Net Pipeline Imports	LNG Imports	LPG Imports	North Slope Gas	Synthetic Gas	Total Supply[a]	Unsatisfied Demand	Percent Demand Unsatisfied
1970 (Actual)	22.6	21.8	0.8	--	--	--	--	22.6	--	--
1975	29.8	19.8	1.2	0.2	0.2	--	0.4	21.7	8.1	27.2
1980	34.5	16.3	1.2	2.1	0.5	1.2	0.6	21.8	12.7	36.8
1985	39.8	13.0	1.2	4.0	0.9	1.5	0.9	21.5	18.3	46.0

a/ Detail may not add to total due to rounding.

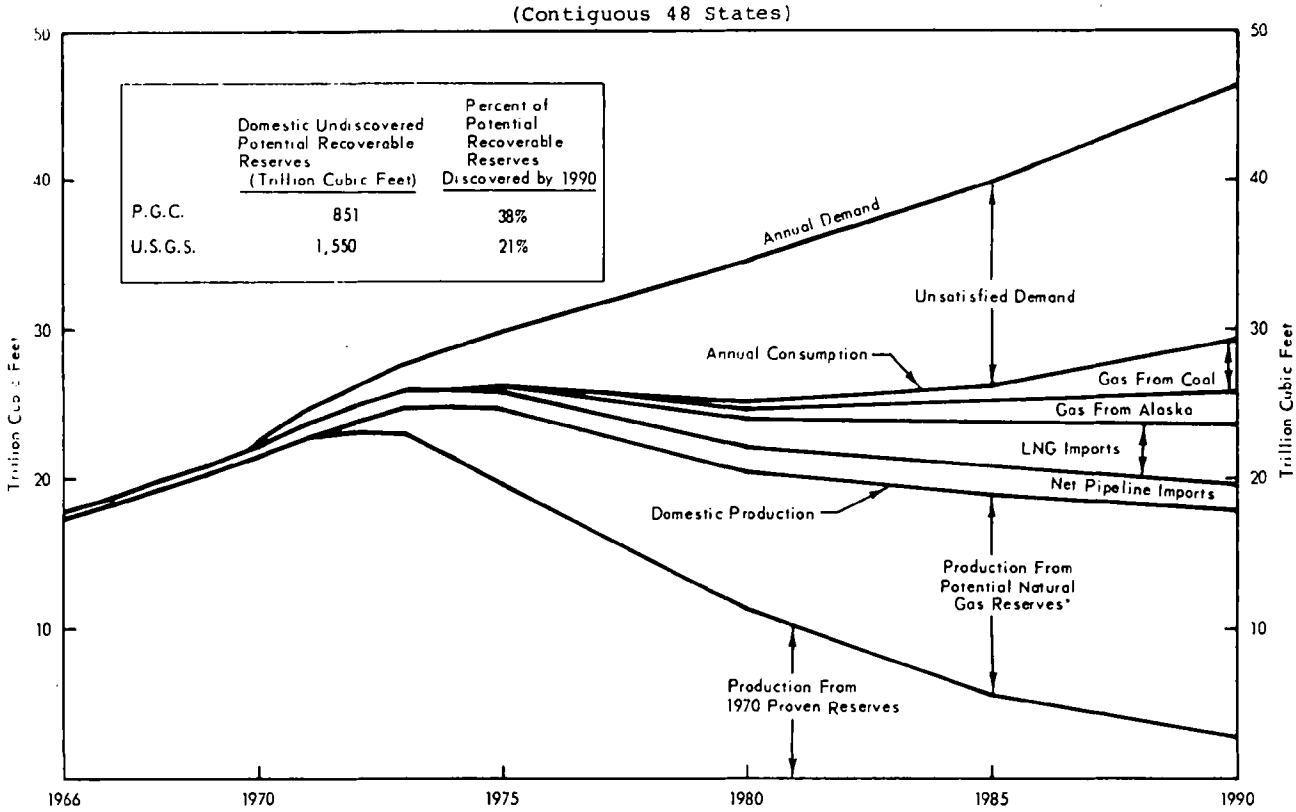
Source: NPC, U.S. Energy Outlook, An Initial Appraisal, 1971-1985, Volume Two, November 1971.

Table V-8

In addition, the Staff's supply projections include supplemental supplies, based essentially on projects now in prospect, including pipeline imports, LNG imports, gas from coal, and gas from Alaska. (Synthetic gas production from liquid hydrocarbons was considered by the Staff to be subject to such rapidly changing trends as to preclude any meaningful estimate at this time.) Even with these sources, the forecast is for a substantial and growing supply gap.

Graphically, the picture portrayed by Staff looks as follows:

UNITED STATES GAS SUPPLY-DEMAND BALANCE
(Contiguous 48 States)



*U.S. Natural Gas Reserve Additions (1971-1990) Total 325 Trillion Cubic Feet.

The potential supply gap indicated by projections of the National Petroleum Council[1/] are even greater. This is primarily because of more pessimistic estimates of domestic production. Assuming wellhead prices based on FPC Staff recommendations in 1971, NPC saw little or no incentive for increased reserve additions, particularly in view of substantially higher costs of deeper drilling and of drilling offshore and in Alaska.[2/]

Estimates of energy supply and demand necessarily depend on a variety of assumptions, which are subject to change in the future. As a result of such changes, many past estimates have missed the mark by wide margins in terms of accuracy of prediction. Notwithstanding this caveat, the above projections illustrate responsible current estimates as to the degree by which supply -- assuming the price and other relevant conditions of today -- will fall short of satisfying expected demand.

4. Potential Gas Reserves

The United States is not short of potential gas supply. The Potential Gas Committee estimated potential reserves as of December 31,

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1/ National Petroleum Council, U.S. Energy Outlook: An Initial Appraisal, 1971-1985, Vol. I, July 1971.

2/ Key assumptions reflected in the NPC forecast are as follows: (a) new gas prices of 26¢/Mcf in South Louisiana and an average of 22.3¢ for the remainder of the Lower 48 States in 1971-1972, each price escalating 1¢/Mcf in 1976, and again in 1981; (b) "old" gas prices continuing at levels lower than new gas supplies; (c) state and federal leasing of approximately one-half million acres each year, consistent with past experience; (d) no important change in federal policies regarding tax incentives and the oil import program; (e) area production constrained by an R/P ratio of 10; and (f) a continuing decline in the productivity of well drilling for nonassociated gas supplies (i.e., reserves added per foot drilled).

1970 at 1,178 trillion cubic feet, about four times the level of estimated proven reserves at the end of 1970 (291 trillion cubic feet, including Alaska). Of this total, 257 trillion are classified as "probable" (extensions of existing fields), 387 trillion are classified as "possible" (new field discoveries in formations previously productive), and 534 trillion are classified as "speculative" (new field discoveries in formations or provinces not previously productive).[1/]

As indicated by Table V-9 on the next page, 613 trillion cubic feet or 52% of the estimated potential gas supply are located in onshore areas of the Lower 48 States, 238 trillion or 20% in offshore areas, and 327 trillion or 28% in Alaska. Thus, nearly half of the supply lies in areas of more costly marine drilling and/or in areas presently inaccessible to markets in the Lower 48 States. Moreover, 162 trillion cubic feet of the onshore potential (or about 13% of the total U.S. potential) are estimated to lie below 15,000 feet in depth.

The U.S. Geological Survey recently estimated undiscovered, recoverable gas at approximately 2,100 trillion cubic feet (plus another 4,000 trillion of submarginal undiscovered gas not considered recoverable

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1/ Potential Gas Committee, Potential Supply of Natural Gas in the United States, October 1971.

The potential gas supply estimates do not include proved reserves -- defined as all gas estimated to be producible from tested formations under existing operating and economic conditions without regard as to size, use, or disposition of any production. Proved reserves in an undrilled area, however, must be so related to the developed or tested leases and to known field geology that its productive ability is assured.

Detailed definitions of the "probable," "possible" and "speculative" categories of potential gas supply are found on page 30 of the above-cited report of the Potential Gas Committee.

U. S. POTENTIAL GAS SUPPLY BY AREA
AS OF DECEMBER 31, 1970

(Trillion Cubic Feet at 14.73 Psia)

Area	Probable	Possible	Speculative	Total
Onshore (Lower 48 States)				
Atlantic Coast and Appalachian (excluding Florida)	25	7	34	66
Florida, Alabama, Mississippi	3	15	14	32
Mid-Continent (north of Arkansas and Kansas)	a/	5	4	9
Arkansas, North Louisiana, East Texas	10	25	58	93
South Louisiana	18	25	3	46
Texas Gulf Coast, South Texas	55	33	15	103
West Texas, Southeast New Mexico	15	32	11	58
Kansas, Oklahoma, Texas Panhandle	27	46	23	96
New Mexico, Arizona	11	a/	5	16
Rocky Mountain	12	30	30	72
Pacific Coast, Nevada, Idaho	1	7	3	11
Subtotal	179	227	207	613
Offshore (Lower 48 States)				
Atlantic Coast	--	--	36	36
Florida, Alabama, Mississippi	--	--	39	39
South Louisiana	31	52	16	99
Texas Gulf Coast	7	40	6	53
Pacific Coast	1	7	3	11
Subtotal	39	99	100	238
Total - Lower 48 States	218	326	307	851
Alaska	39	61	227	327
Total - United States	257	387	534	1,178

a/ Less than 1 trillion cubic feet.

Source: Potential Supply of Natural Gas in the United States as of December 31, 1970, Potential Gas Committee, October 1971.

today).[1/] The total of 2,100 trillion cubic feet includes 1,000 trillion, or 48%, in the Lower 48 States onshore; 850 trillion, or 40%, in offshore areas (including Alaska); and 480 trillion, or 22%, in Alaska (including offshore and onshore).

Potential gas reserves in Canada have also been estimated to exist in abundant quantities [2/] -- but again in large part in frontier areas which are relatively inaccessible and costly for exploration and drilling. In 1969 the Canadian Petroleum Association published an estimate totalling 725 trillion cubic feet, broken down by area as follows:

Area	Trillion Cubic Feet
Western Canadian Sedimentary Basin (principally includes Alberta, plus a corridor northwest along the Mackenzie River to the Arctic Ocean)	270
Arctic Islands	261
Eastern Canada Offshore	150
Hudson Bay	17
Gulf of St. Lawrence	11
British Columbia Offshore	11
Other	5
	725

Finally, in view of the expectation of growing LNG imports into the United States, it is of interest to examine natural gas reserve estimates for different countries of the world. These estimates are shown on

1/ Geological Survey Circular 650, Energy Resources of the United States.

2/ Proved reserves in Canada represent a different situation. According to the Reserves Committee of the Canadian Petroleum Association, remaining marketable natural gas reserves in Canada as of December 31, 1971 totalled 55.5 trillion cubic feet -- equivalent to only 20% of the estimated remaining proved reserves in the United States at the end of 1971.

Table V-10. Two facts are particularly noteworthy. One is the discrepancy between the proportion of proved world reserves controlled by the United States (only about 16%) and its proportion of world gas production (over 50%). Second is the magnitude of overall proved world reserves controlled by the USSR (32%), the Middle East (20%) and Africa (11%) -- a total of 63%.

Estimated reserves and production for countries mentioned as possible sources of LNG for U.S. markets at some future time are compared below.

	Reserves	Production
	(Billion Cubic Feet)	
Algeria	106,500	105
Nigeria	40,000	141
Libya	29,500	645
Iran	200,000	1,245
Venezuela	25,400	1,838
Ecuador	6,000	3
Trinidad and Tobago	5,000	117
Australia	24,800	98
Indonesia	4,500	113
USSR	546,000	7,484

B. Proposed Sanctity of Contract Legislation

Assuming reactivation of the sanctity of contract bills before the last Congress, it is recommended that EPA join with other federal government bodies -- including the Departments of Interior and Commerce, and the Office of Management and Budget -- which have supported this legislation. These bills would not bring about decontrol of producer prices. Rather, they are intended to remove some of the difficulties which have hampered effective regulation in the past and have contributed to the drop-off of exploratory efforts.

ESTIMATED PROVED WORLD GAS RESERVES AND PRODUCTION BY COUNTRY

1971

(Volumes in Billions of Cubic Feet)

Country	Total Production	Year-End Proved Reserves	R/P Ratio	Percent of World Production	Percent of World Reserves
			North America		
United States	22,949.1	278,800	12.1	51.2	16.0
Canada	2,987.8	55,400	18.5	6.7	3.2
Total	25,936.9	334,200	12.9	57.9	19.2
			Latin America		
Argentina	285.0	7,600	26.7	0.6	0.4
Bolivia	100.9	5,000	49.6	0.2	0.3
Brazil	43.6	5,000	114.7	0.1	0.3
Chile	233.4	2,200	9.4	0.5	0.1
Columbia	83.6	2,500	29.9	0.2	0.1
Ecuador	3.2	6,000	1,875.0	--	0.4
Mexico	660.9	11,500	17.4	1.5	0.7
Peru	0.6	2,500	4,166.7	--	0.1
Trinidad and Tobago	117.4	5,000	42.6	0.3	0.3
Venezuela	1,837.5	25,400	13.8	4.1	1.5
Total	3,366.1	72,700	21.6	7.5	4.2
			Europe		
Austria	68.1	550	8.1	0.2	--
Denmark	--	500	--	--	--
France	287.4	6,900	24.0	0.6	0.4
Italy	460.8	6,000	13.0	1.0	0.3
Netherlands	1,537.3	83,000	54.0	3.4	4.8
Norway	--	10,000	--	--	0.6
Spain	--	500	--	--	--
United Kingdom	666.9	40,000	60.0	1.5	2.3
West Germamy	488.5	14,000	28.7	1.1	0.8
Yugoslavia	45.0	1,800	40.0	0.1	0.1
Total	3,554.0	163,250	45.9	7.9	9.3
			Africa		
Algeria	105.1	106,500	1,013.3	0.2	6.1
Angola	11.7	1,500	128.2	--	0.1
Egypt	39.3	7,500	190.8	0.1	0.4
Gabon	131.0	6,500	49.6	0.3	0.4
Libya	644.6	29,500	45.8	1.5	1.7
Morocco	1.2	18	15.0	--	--
Nigeria	140.8	40,000	284.1	0.3	2.3
Tunisia	0.9	1,500	1,666.7	--	0.1
Total	1,074.6	193,000	179.6	2.4	11.1

ESTIMATED PROVED WORLD GAS RESERVES AND PRODUCTION BY COUNTRY

1971

(Volumes in Billions of Cubic Feet)

Country	Total Production	Year-End Proved Reserves	R/P Ratio	Percent of World Production	Percent of World Reserves
			Near East		
Abu Dhabi	--	10,000	--	--	--
Bahrain	16.0	5,000	312.5	--	0.3
Dubai	--	1,000	--	--	0.1
Iran	1,245.1	200,000	160.6	2.8	11.5
Iraq	18.0	22,000	1,222.2	0.1	1.3
Israel	3.1	60	19.4	--	--
Kuwait	--	35,000	--	--	2.0
Neutral Zone	--	8,000	--	--	0.4
Oman	--	2,000	--	--	0.1
Qatar	3.0	8,000	2,666.7	--	0.4
Saudi Arabia	--	52,000	--	--	3.0
Syria	--	700	--	--	--
Turkey	--	170	--	--	--
Total	1,285.2	343,930	267.6	2.9	19.7
			Asia Pacific		
Afghanistan	91.5	4,900	53.6	0.2	0.3
Australia	98.0	24,800	253.1	0.2	1.4
Bangladesh	20.0	4,000	200.0	--	0.2
Brunei-Malaysia	--	7,500	--	--	0.4
Burma	2.2	100	45.5	--	--
India	16.0	1,500	93.8	--	0.1
Indonesia	113.2	4,500	39.8	0.3	0.3
Japan	85.4	400	4.7	0.2	--
New Zealand	1.9	6,000	3,157.9	--	0.4
Pakistan	115.1	15,500	134.7	0.3	0.9
Taiwan	24.1	600	24.9	0.1	--
Total	567.4	69,800	123.0	1.3	4.0
			Soviet Nations		
Albania	--	300	--	--	--
Bulgaria	1.8	1,000	555.6	--	0.1
China	149.5	4,000	26.8	0.3	0.2
Czechoslovakia	31.0	500	16.1	0.1	--
East Germany	--	500	--	--	--
Hungary	127.6	3,000	23.5	0.3	0.2
Poland	187.3	5,000	26.7	0.4	0.3
Romania	1,001.2	6,000	6.0	2.3	0.4
USSR	7,483.6	546,000	73.0	16.7	31.3
Total	8,982.0	566,300	63.0	20.1	32.5
Total World	44,766.2	1,743,180	38.9	100.0	100.0

Source: International Petroleum Encyclopedia, 1972.

Hearings were held in September 1971 by the Subcommittee on Communications and Power of the House Interstate and Foreign Commerce Committee on H.R. 2513 (introduced by Rep. Murphy of New York) and in March 1972 by the Senate Commerce Committee on S. 2505 (introduced by Senator Hansen of Wyoming) and S. 2467 (introduced by Senator Hollings of South Carolina).[1/] The basic purpose of these bills is to immunize new producer contracts -- once approved by a final FPC order -- from subsequent change by the Commission. Such contracts, however, would have to be submitted to the FPC for initial review to determine whether they are just and reasonable and required by the public convenience and necessity. This review would extend to the entire pricing structure (initial price plus provisions for fixed escalations), the length of the contract and other contract terms. In passing on the contracts, the Commission would be prohibited from using the cost of service, public utility rate base method and instead would look to supply and demand factors, price levels estimated to be required to elicit adequate supplies for the interstate market, and economic and cost trends.

The sanctity of contract legislation would permit a producer to begin deliveries pending FPC review of his contract. If review were completed within nine months from the date of filing of the contract, the producer would be required to refund any amounts which the Commission might determine to be unreasonable, or else could terminate deliveries. However,

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1/ H.R. 2513 and S. 2505 are identical, and S. 2467 differs only with respect to small producers.

if the FPC failed to reach a decision in nine months, no refunds could be ordered.

Under the bills, the FPC would also be prohibited from reducing any rate in an existing contract approved after the date of enactment. But it would retain authority to act on any price increases of an indefinite nature in both existing and future contracts.

Finally, the sanctity of contract bills would exempt small producer contracts (involving daily contract quantities not more than 10,000 Mcf/d) -- or, in the case of S. 2467, small producers (those with annual jurisdictional sales not more than 10,000,000 Mcf)[1/] -- from FPC regulation.

Introduction of the above bills was preceded by extensive efforts by distributors, pipelines and producers to work out an acceptable legislative package to all three branches of the natural gas industry. That such efforts were successful deserves mention, considering differences which divided especially distributors and producers in the past.

A major benefit of the sanctity of contract legislation would be the avoidance of the price confusion and risk which characterized guideline and in-line pricing policies in the 1960's. In South Louisiana, for example, the FPC twice rolled back the guideline levels and then, in 1968, set area price levels below these guidelines. Such action was hardly inducive to producers to commit new reserves to the interstate market as

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1/ This version of the small producer exemption would, in effect, codify action already taken by the FPC to exempt small producers from nearly all regulatory requirements. The FPC action, however, still faces judicial review.

opposed to the intrastate market where contract terms were binding. While sanctity of contract assurance would not guarantee commitment of gas to interstate markets, it would considerably strengthen the competitive position of purchasers of interstate gas.

Another principal benefit of the proposed sanctity of contract legislation is that it would free the FPC once and for all from the cost of service ratemaking method. Although there are some (e.g., the American Public Gas Association and certain other consumer groups) who maintain that the cost of service approach is the only means of protecting consumers against unjust and unreasonable rates, it is our view that experience in the area rate proceedings over the past decade has demonstrated application of the cost method to producers on an area basis to present nearly as many difficulties as its application on an individual company basis. Significantly, in two recent area rate decisions, the FPC recognized that cost calculations cannot be mathematically precise, but rather reflect arbitrary judgments as to allocation procedures and a wide margin of error as to both data and methods used.[1/] Relieved from any precedents or pressures to attempt to apply this method further for new gas supplies, the FPC could proceed to develop more rational regulatory standards giving greater recognition to market forces and the incentives necessary to elicit greater supply additions.

With a few exceptions, critics of the bills do not oppose the sanctity of contract concept but argue rather that the proposed legislation

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1/ FPC Opinion 595 issued May 6, 1971 in the Texas Gulf Coast Area Rate Proceeding, AR64-2, et al., FPC Opinion No. 598 issued July 16, 1971 in the Southern Louisiana Area Rate Proceeding (AR69-1 et al.).

goes beyond what is necessary to accomplish that goal.[1/] For example, it is claimed that only a relatively simple amendment to the Natural Gas Act is needed to provide that a rate, once permanently certificated or found just and reasonable, would not thereafter be subject to reduction.

One of the chief objections to the sanctity of contract bills, in the form presented to Congress, is that sanctification of contract termination provisions would destroy the assurance of supply continuity now provided under the abandonment provisions of the Natural Gas Act[2/] and would encourage short-term sales contracts, with disastrous price consequences under gas shortage conditions. Other objections are that the legislation would create as much new confusion as it would eliminate as the FPC struggled to develop new regulatory standards, that nine months is far too short a time for FPC review of new contracts, that the cost of service method of ratemaking should not be outlawed entirely but rather should be made a factor for consideration at the FPC's discretion, and that exemption of contracts covering daily volumes up to 10,000 Mcf/d would result in freeing a substantial portion of sales by large producers from regulation.

These and other objections reflect a fear of departing very far from the present regulatory scheme. Without undertaking here to answer all of the objections, it appears obvious that the supply deficiencies

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1/ Joseph Swidler, FPC Chairman from 1961 to the spring of 1966, takes this position, among others.

2/ As discussed in Chapter IV, no producer may now abandon sales to an interstate pipeline, even after their contract has expired, without FPC approval. Such approval is generally not given except in the case of depletion of supply or uneconomic production.

projected for the future are sufficiently great as to warrant at least the remedies sought by the sanctity of contract legislation. The most serious reservation relates to the potential for short-term contracts and decrease in assured continuity of supply. However, the inability of producers to terminate deliveries upon expiration of a contract is undoubtedly a factor contributing to the area of uncertainty. Further, it has been argued that, even if there were a trend toward contracts shorter in duration than the 20-year term typical in the past, elimination of the need to provide for contract price escalations for so long a period in the future could result in lesser price increases than might otherwise prevail.

C. Legislation to Decontrol Wellhead Prices

Legislation to deregulate wellhead sales is urged by those who believe that the sanctity of contract proposal does not go far enough in restoring the ability of gas prices in the field to react to market forces. Basically, the argument is that in a workably competitive industry, the balancing of supply and demand is best achieved through the workings of the market place. Efforts of the FPC to approximate the functioning of the market place, the argument continues, are beyond its capability -- and, indeed, beyond the capacity of any regulatory body -- and hence are doomed to failure. Thus, the regulation of the producing industry having led to a serious imbalance of supply and misallocation of resources, the market should be allowed to return to its traditional economic function.

As one advocate expressed it:

"Whether imposed by statutory amendment or by Commission election to alter the existing area rate methodology, any approach requiring the determination of producer prices by the Commission on the basis of some subjective market standard or criteria would fall far short of a satisfactory solution. Such standards are extremely difficult to define and thus are usually couched in general terms and, as a result, the Commission would be compelled in all likelihood to define, qualify and quantify the innumerable factors that could affect the market and might have to be considered in each instance. To submit market forces to the subjective interpretation of a regulatory body, regardless of its expertise or good intentions, can only lead to a distortion of their effect with imprecise and unresponsive results. In the final analysis, . . . establishment . . . of a market value as the permissible price level . . . can be more readily and accurately achieved by the free interplay of supply and demand dynamics unencumbered by any futile regulatory attempt to decipher the complicated considerations and the subtle interrelationships involved in a free market. Inject market forces into the administrative crucible and no one will recognize the results." 1/

Deregulation proposals take three general forms: decontrol of all gas (under both new and existing contracts), decontrol of gas under new contracts only, and decontrol of new gas contracts subject to certain safeguards. In the third category, bills were introduced in the last two sessions of Congress by Senator Tower and Rep. Price (both of Texas) to eliminate FPC rate control over future contracts, provided that (1) the acreage involved had not previously been dedicated to the interstate market, (2) contract prices, including any escalations, are expressed in terms of a definite charge per unit, with indefinite price escalations prohibited, (3) all other contractual provisions (such as quality, rate of take, prepayment arrangements, and abandonment of service), regardless of their effect upon contract prices, continue to be subject to Commission

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1/ Address by Carl E. Bagge before the annual meeting of the American Association of Oilwell Drilling Contractors in Dallas, Texas on September 24, 1970. Mr. Bagge was then a member of the FPC.

approval and review. The form of this legislation was suggested by former FPC Commissioner Carl E. Bagge.

Decontrol of producer prices for new gas are known to be under active consideration by the Administration at this time. Support for legislation of this nature has been expressed by officials of the Interior, Commerce and State Departments, and by the Director of the Office of Emergency Preparedness. The President's Council of Economic Advisers has endorsed action to allow the price of gas, at least new gas not previously dedicated to interstate purchasers, to approach market-clearing levels.[1/] In addition, two current FPC members -- Pinkney Walker and Rush Moody -- favor immediate decontrol of domestic wellhead prices. Commissioner Walker[2/] has taken the position that there was no valid economic basis for subjecting producer sales to federal regulation in the first place and, given the present state of affairs, no reason for perpetuating this regulation. Failure to decontrol, and thereby permit gas producer prices to reach market-clearing levels, will prevent domestic production and exploration from competing for investment dollars.[3/]

On the other hand, efforts to deregulate producers are likely to face opposition from the distributor segment of the industry[4/] and are

1/ Annual Report of Council of Economic Advisers, January 30, 1971.

2/ Commissioner Walker resigned on December 31, 1972 -- following the drafting of this report.

3/ Address of FPC Commissioner Pinkney Walker to Pacific Coast Gas Association, September 21, 1972.

4/ A recent speech by the outgoing President of the American Gas Association indicates a concern of this approach. In an address to the AGA annual convention on October 16, 1972, Ralph T. McElvenny warned against regarding deregulation of producer prices or substantially higher ceilings as the answer to the supply problem.

sure to be opposed by many other interests as well. Among others, FPC Chairman Nassikas and recently resigned Commissioner John A. Carver, Jr. have come out against deregulation on the principal ground that the results would be chaotic in a time of supply shortage. They and others question whether producer markets are sufficiently competitive to permit adjustment to realistic price levels and whether, once gas price ceilings are removed, interfuel competition could provide any meaningful restraints on increasing gas prices. The answer, they contend, is not elimination of regulation but rather more intelligent regulation giving greater weight to marketplace operations.

Further, the reaction of Congress to any decontrol proposals is problematical at best. The sanctity of contract bills did not go beyond committee hearings in the last session. Some 35 members of Congress attacked the FPC for a recent measure (the "optional certification procedure") to permit prices higher than area ceilings for new sales under certain conditions, including 19 House members who have appealed this action to the courts. Hence, decontrol measures are clearly uncertain of passage.

Substantively, decontrol proposals raise fundamental questions affecting policy alternatives. One problem involves the degree to which producers are competitive, i.e., whether market prices will be set by competitive forces or will reflect a bargaining edge on the part of producers. By traditional measures of concentration of control, the producing industry is highly competitive. Large numbers of producers compete for leases and sell natural gas. On the other hand, it is contended that

the bargaining motivation of pipelines is diluted by their ability to pass on all gas purchase outlays to their customers in resale rates. Therefore, any inequality which may exist between sellers and buyers is greatly enhanced in favor of the sellers in a time of supply shortage.

A second problem concerns the extent to which the price of gas would rise and the degree to which supply would increase if FPC wellhead regulation were eliminated. The price elasticity of supply is a much studied topic, both in academic and regulatory circles. No definitive answers have been reached, and study is complicated by the large number of variables which must be considered in the overall picture. There is general agreement, however, that supply is responsive to price -- although with reservations as to how much and over what period of time. Some fear that the response would not come close to matching the public expectations created by the sharp price rises which would result from decontrol of either all producer prices or new gas prices only.[1/] This, in turn, could cause a "backlash" reaction and pressures for even more stringent price controls than now apply. It is also suggested by some observers that prices might exceed market-clearing levels in the short term until producers were able to respond to the new incentives or consumers were able to either reduce consumption or switch to alternative fuels, thereby balancing supply and demand.

1/ At least one suggestion has been made for decontrol of new gas prices on an experimental basis, for a period of three years, to test the supply-price relationship. (Statement of John F. O'Leary, former Interior Department and FPC Staff official, before the Joint Economic Committee, June 8, 1972.)

Despite the uncertainties and reservations concerning the effects of decontrol, legislation in this direction would assuredly spur greater exploratory efforts and lead to increased gas supply additions. The need for development of market-based pricing criteria by the FPC, a task which would undoubtedly be attended by enormous complexities and litigation, would be avoided. Presumably, any need for end-use rationing by administrative decree, again a task entailing subjective judgments, would also be obviated. These are all desirable objectives.

Should EPA desire to support the decontrol route, perhaps the type of proposal most likely of passage by Congress[1/] (and the one least disruptive to present consumer markets) would be legislation along the lines proposed by Senator Tower. In other words, deregulation would be limited to new gas contracts only, with safeguards to preserve some measure of FPC control or alternatively to provide for some type of arrangements for monitoring the competitiveness of market behavior. For example, it might be possible to establish a system of continuing contract surveillance to signal whether a contract were out of line with expected market behavior. Investigations could then be launched to determine whether observed variations from expected values are explained by market conditions.

D. Legislation to Expand Federal Regulation

Another general approach advocated to meet the current gas shortage is the expansion, not the reduction, of federal regulation. In broad form, this approach contemplates the establishment of a national system of

1/ As discussed supra, we make no prediction as to the success of a decontrol bill in any form in the Congress.

end-use priorities, with uses at the low end of the scale to be proscribed to the extent needed to balance sales with deliverable supplies, together with extension of FPC jurisdiction to cover regulation of intrastate sales and direct industrial sales by producers and pipelines.[1/]

Among the proponents of this course of action are two former FPC Chairmen, Joseph C. Swidler (now Chairman of the New York Public Service Commission) and Lee C. White. (Mr. Swidler served as Chairman from 1961 to 1966 and Mr. White from 1966 to 1969.) Suggestions for the establishment and implementation of gas rationing plans by the federal government are being voiced with increasing frequency by others as well.

A major argument advanced in support of FPC regulation of intrastate and direct industrial sales is the need to prevent unregulated markets, primarily in producing states, from siphoning off most new gas production for low priority uses -- such as boiler fuel -- while other states are experiencing shortages for preferred uses. To illustrate the extent to which such siphoning off has already occurred, it is pointed out that the proportion of new gas committed to intrastate markets from the Permian Basin producing area rose from about 16% in 1966 to over 90% in the first half of 1970. It is thus argued that regulatory exemption

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1/ Last June, Senator Griffin of Michigan introduced a bill (S. 3794) to grant the FPC authority to regulate intrastate transportation and sales for resale, as well as direct industrial sales whether in interstate or intrastate commerce. No hearings were held, and no action was taken on this bill in the last Congress.

With respect to direct industrial sales by pipelines, the FPC has been held by the Supreme Court to have jurisdiction over curtailments by virtue of its authority over the transportation of gas in interstate commerce.

which permits the channeling of scarce gas supplies to a few favored areas should be eliminated.

Pressures for federal end-use controls over all gas markets reflect growing concern respecting the potential consequences of gas supply curtailments. If the present gas situation continues to deteriorate, some sort of controls may be needed to avoid curtailment of service to existing residential and commercial customers who have no feasible alternative to use of gas. However, a near insuperable question is what class or classes of customers should be forced to suffer delivery reductions in order to enable continued service to other classes. While there is little dispute that residential and commercial categories deserve the highest priority, who is to determine the lowest priority? Those advocating end-use controls generally cite boiler fuel as the "most inferior" use. Such a flat condemnation, however, is subject to controversy in view of the need for gas -- assuming no other available clean-burning fuels -- to meet air pollution standards.

Moreover, the experience in pipeline curtailment proceedings before the FPC has demonstrated the difficulties in formulating acceptable and equitable priorities for customers of individual pipelines. To attempt to apply a single set of priorities to all areas of the nation would be an extraordinarily difficult task. Patterns of gas usage vary considerably in different regions, so that an ordering of equitable priorities in one area would not necessarily be a reasonable or fair solution in another area. In short, the problems associated with comprehensive end-

use regulation by the FPC or any other federal body seem so formidable as to dictate avoidance of this approach if at all possible. 1/

Above all, proposals for end-use control and/or intrastate sales regulation constitute measures for coping with the gas shortage, not for relieving it. In terms of eliciting additional supplies of gas, their effect would appear to be nil -- or perhaps even counterproductive for the reason that increased regulation could create a disincentive for investment. On the other hand, if wellhead prices were permitted to rise to realistic market levels, purchasers of gas for interstate markets should again be able to compete with intrastate purchasers, and the tendency for newly available gas supplies to be committed to intrastate markets should diminish.

One suggested variation of the end-use control approach would be to allow a material increase in the price of new gas to encourage greater resource development and at the same time to impose a national excise tax on the ultimate sale of gas, with the tax heavier on the less preferred uses and zero on the "highest" uses. 2/ Receipts from these taxes would be paid into a "gas supply trust fund" which could be used by the government for expanded research and development programs, nuclear fracturing,

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1/ Even so, the deterioration in the gas supply situation recently caused the FPC to establish eight end-use priorities for use by all interstate pipelines throughout the nation during periods when curtailments of service are necessary (FPC Order No. 467, issued January 8, 1973). In addition, the FPC has advanced a proposal to adopt the same priorities nationwide in considering applications for sale of new or increased gas supplies (Docket No. R-467).

2/ Statement of Charles H. Frazier, independent consultant, before the Joint Economic Committee, June 7, 1972.

offshore Atlantic exploration, and numerous other such purposes. A basic difficulty with this proposal is that it is predicated on the establishment of national end-use priorities which, as discussed above, involves enormous complexities. It is also difficult to perceive how the proposal would lead to any significant expansion of supply since a large portion of any permitted increase would go to the U.S. Treasury rather than to producers who need incentive to develop domestic gas resources in the years ahead.

Still another suggestion which has been advanced by others is the creation of a federal government corporation to explore for oil and gas on publicly-owned lands. Two particular advantages of such a corporation are pressed: a singular motivation to expedite maximum development of resources on federal lands, and the derivation of first-hand data on costs and other aspects of gas operations which individual producing companies are reluctant to disclose on confidential grounds. One of the proponents of this proposal is former FPC Chairman Lee White. In hearings before the Senate Interior Committee in February 1972, Mr. White testified as follows:

> "A government-owned corporation to explore for and develop petroleum resources on publicly-owned lands could serve to supplement the privately-owned segment of the petroleum industry, and, although it should manage the nation's resources in an efficient manner and on a profit-making basis, it would also be expected to be strongly motivated by the need to meet national energy requirements. One of the recurring problems faced by the FPC and the government generally has been the reluctance of the natural gas industry to make available data relating to their gas operations. This has made even more difficult the FPC's job of establishing area rates . . . . [T]he existence of a National Energy Resources Corporation operating in these areas would be extremely useful in supplying information and

data on actual costs and operations in a field that has proved to be most difficult to regulate. This nation has been willing to use its wealth and its resources in a proprietary manner when convinced that such an approach was the best solution to a national problem -- stockpiling of strategic goods, development and ownership of nuclear devices, and operation of the Alaska railroad, to name a very few." 1/

However, the wisdom of establishing a government corporation to attain these goals is questionable. From the standpoint of stimulating greater additions, it is unclear what a federal corporation could do that private companies could not do with a much shorter time lag, given adequate price incentives. Also, in the absence of very sizeable appropriations, a government corporation could explore and develop only a small portion of public lands. Further, there can be no assurance that a government corporation would operate efficiently and hence provide any reliable information for yardstick purposes.

E. FPC Modification of Producer Regulation

As indicated in a previous section, the FPC has recognized the current shortage of natural gas and acknowledged the role of past pricing policies in causing the supply situation today. Moreover, the Commission has taken a number of measures in an attempt to alleviate the shortage, some more far-reaching than others. In part, the outcome of these measures is uncertain due to pending judicial review proceedings.

There are two basic types of actions available to the FPC to induce increased gas supply. The first is allowance of higher field prices in order to restore incentive for an adequate level of exploratory

1/ Statement of Lee White, former FPC Chairman, before the Senate Committee on Interior and Insular Affairs, February 25, 1972.

and developmental effort. The second is encouragement of gas exploration and production operations by as broad a segment of companies as possible. This includes pipelines and distributors.

1. Optional Certificate Procedure

On August 3, 1972 the FPC adopted an optional procedure for certificating new gas sales (Order No. 455), clearly its most innovative supply-inducement step taken to date. The new procedure is intended to provide two incentives to domestic production: authorization of sales of gas not previously available to the interstate market at prices in excess of area prices (specifically, at a price "shown to be in the public interest"), and reduction of future rate uncertainty to the extent possible within the FPC's present statutory powers.

The new measure is also intended as a response to the dilemma of certificating new base load supplies of substitute or supplemental gas at prices significantly higher than the prices of currently available domestic wellhead supplies. The Commission explained:

> "In summary, if our domestic natural gas resources are not developed in a timely manner and consumers of natural gas are forced to satisfy a commensurately larger portion of their energy requirements by using either substitute or supplemental gas supplies, e.g., imported liquefied natural gas, propane, reformed hydrocarbons, gasified coal, imported natural gas, or other fossil fuels, the net effect is higher energy costs throughout the economy, with resulting inflationary pressures. Higher prices for domestic gas, if paid for new supplies, will result in a cheaper mix of energy supplies and thus represent a better alternative.
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> "In view of these facts, we are unwilling to leave untested the producing capacity of the United States." (Order No. 455, Mimeo, p. 3.)

The optional certificate procedure is available for both long-term and short-term contracts covering sales to interstate pipelines of gas produced from wells commenced after April 6, 1972 (the date the Commission gave notice of its proposal to adopt the new procedure), and sales of gas not previously sold in interstate commerce except under emergency procedures. However, use of the optional procedure is subject to the following restrictions, among others: (a) the seller under the contract must have discharged, or be prepared under an acceptable plan to discharge, all refund obligations owing under past FPC orders for sales in the same geographical area as the production covered by the contract; (b) the contract must contain no indefinite pricing clauses (with certain limited exceptions), including provisions for adjustment to any higher area rates which might subsequently be fixed (so-called area rate clauses); (c) the seller must agree to waive all rights to contingent future escalation of rates provided in past area rate decisions for flowing gas produced in the same geographical area as the production covered by the optional procedure application;[1/] (d) deliveries may commence pending FPC review but must be made at applicable area ceiling rates for a period of six months (although thereafter may be made at contract rates without refund obligation if the Commission has not acted); and (e) the seller must provide "factual support" demonstrating why the requested certification is required by the public convenience and necessity, and the purchaser must provide

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1/ This condition would bar producers from claiming any rate escalations provided in the FPC's area rate decisions for the South Louisiana area (Opinion No. 598) and Texas Gulf Coast area (Opinion No. 595) contingent upon industry dedication to interstate commerce of specified quantities of new gas reserves over roughly the next five years.

information respecting systemwide supply, deliverability life, implementation of any curtailment plans, emergency purchases of gas, and purchases of LNG or other supplemental supplies.

The FPC stressed, and the restrictions imposed so reflect, that the new procedure is not meant to supplant area rate procedures but rather to provide an alternative for producers willing to forego certain advantageous features of the South Louisiana and Texas Gulf Coast area rate opinions in exchange for greater certainty of certificated prices. As to certainty, the FPC acknowledged that it cannot bind future Commissions not to modify rates prospectively under Section 5 of the Act. But, under the optional procedure, the FPC intends to examine the justness and reasonableness of the proposed rates at the time of certification in an effort to avoid subsequent rate determinations under either Section 4 or 5. Thus, it is the Commission's intent to provide certainty of rates to the extent it is able to do so. However, given the limits of the Commission's ability in this regard, it is clear that the need for legislation to assure contract sanctity has not been eliminated.

While Order No. 455 promulgating the optional certificate has been heralded as a positive step in the direction of encouraging needed exploration and development of new gas supplies,[1/] it is by no means

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1/ In Order No. 455, the FPC called particular attention to comments expressed by the Departments of Commerce and Interior, and by the Environmental Protection Agency, in favor of the new procedure. However, the FPC ignored EPA's further suggestion that pipeline companies receiving additional gas supplies certificated under the optional procedure should be required to submit end-use information respecting the additional volumes.

universally accepted or free from reservations respecting its potential effectiveness.

For example, nearly all producers took the position -- in comments filed prior to the adoption of the rule -- that the necessity to give up contingent escalations of flowing gas rates provided in the South Louisiana and Texas Gulf Coast area decisions would largely nullify the incentive offered by the new procedure and defeat its purpose, particularly for companies with substantial flowing gas production in areas holding the greatest promise for new gas discoveries. There is little logic, the producers contended, in holding out an incentive in the form of above-ceiling rates for new gas dedications and then reducing or removing it by a penalty on flowing gas rates.

From the other side, at least 15 Senators and 20 Congressmen -- as well as certain consumer interest groups -- accused the FPC of usurping the legislative function by seeking to effect, through administrative action, the "sanctity of contract" proposals then pending before Congress. The FPC's new procedure was further condemned as tantamount to deregulation of all new gas sales in defiance of Congressional intent underlying the Natural Gas Act. Some legislators additionally contended that area rates permitting the recovery of all expenditures incurred in exploration, development and production of gas, plus a 15% return, constitute adequate incentive to bring forth the necessary supplies. Consequently, they concluded, the end result of the Commission's actions will be to provide a "multi-billion dollar windfall" to producers at the expense of the gas consuming public which the Natural Gas Act is intended to protect. Figures up to $1 trillion

were thrown out as estimates of the potential windfall to producers and cost to consumers.[1/]

More temperate critics question whether the Commission's optional procedure will be effective in channeling new supplies to the interstate markets since such markets are likely to be always outbid by intrastate markets as long as intrastate sales remain unregulated. Hence, the problem arises as to whether the additional supplies induced by the procedure will be worth the additional costs to consumers. Further criticism has been directed to the FPC's decision to allow use of the optional procedure for short-term as well as long-term contracts, and to the provision allowing producers to charge contract rates without refund obligation after six months if the FPC had not acted on an application by that time. Essentially, these are the same objections raised with respect to the sanctity of contract bills before the last Congress.

The above described pleadings reflect the political pressures pervading the natural gas pricing issue. They also illustrate the difficulties

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1/ The derivation of these estimates is of interest in illustrating the type of political response evoked by the producer pricing issue. For example, the $1 trillion figure was calculated by applying an assumed increase of approximately 50¢/Mcf over present wellhead prices to 2,100 Tcf of potential reserves estimated by the U.S. Geological Survey. Application of the same assumed increase to 1,178 Tcf of potential reserves estimated by the Potential Gas Committee yielded a figure over $500 billion. Another calculation applied an assumed price of 75¢/Mcf to potential reserves "conservatively" estimated at 1,000 Tcf, resulting in an estimated "windfall" of $750 billion. These calculations are without rational foundation. Not only do they fail to reflect that potential domestic supplies of gas will be more expensive to develop than supplies consumed in the past, but also no account is taken of the inflation factor which would erode the purchasing power of money over the very long period of time required to realize these reserves, if indeed they are proven to exist.

faced by the Commission in seeking to adopt effective measures to stimulate increased exploratory and development efforts. Despite the severe decline in overall proven U.S. reserves and in supplies dedicated to interstate pipelines, opposition persists to abandoning past regulatory procedures -- however ineffective they may have proved in terms of eliciting supply. Moreover, opponents take their case to the courts, where litigation leads to further delay as well as the risk of judicial reversal of any significant departures from past precedent.

The ultimate outcome of Order No. 455 is unclear, both because of court appeals brought by a group of "Concerned Congressmen" and the American Public Gas Association and because of uncertainty as to the guidelines and criteria to be applied by the Commission in certificating new sales under the optional procedure. Moreover, assuming court affirmation and the formulation of reasonable certification standards, it will be some years before the procedure can be evaluated in terms of supply response and dedications.[1/]

2. Increase in Area Rate Ceilings

Another course of action open to the FPC is to raise area rates -- either for new gas, or for both new and old gas -- in order to give greater recognition to market value factors, including prices negotiated for intrastate sales, prices of competitive fuels, and cost and economic

1/ Thus far, Order No. 455 has not generated much response. In the four months since its adoption, only four applications have been filed under the optional certificate procedure. One application -- for sales in the Texas Panhandle at a price (26.5¢) no higher than the level already approved for sales in an adjacent producing area -- was certificated on November 8, 1972. (McCulloch Oil Corp., Docket No. CI73-133.)

trends. This might be done through a reopening of the area proceedings, consideration of petitions to amend the area ceilings, or possibly through the establishment of some type of index (such as the BLS wholesale price or consumer price indexes) permitting periodic price adjustments in accordance with changes in specific economic or cost indicators.[1/]

At present, the FPC has under consideration a petition to raise the ceiling rate for new gas production in the Appalachian Basin area (specifically, gas under contracts dated after February 1, 1972) from 32¢ and 34¢/Mcf to 50¢. This petition has received widespread support and no opposition (other than suggestions for still higher ceiling prices or for increases in flowing gas rates as well). Given this relatively unique state of affairs, coupled with the possibility of significant production increases from deeper drilling, the petition should be granted by the FPC without further delay.[2/]

An increase in flowing gas rates deserves serious consideration. The dual price system adopted by the Commission in the past was based on the notion that incentive is provided only through rates for new gas since the capital behind existing or flowing gas production has already been invested. This argument ignores the fact that net revenues from flowing

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1/ The establishment of price adjustment indexes based on supply and demand data was urged by former Commissioner Bagge as a means of permitting the FPC to react effectively and expeditiously to changing situations.

2/ The petition was denied by the FPC in Opinion No. 639, issued December 12, 1972. The Commission instead suggested increased use of the optional certificate procedure. The FPC also explained that its past practice of setting area rates by contract vintage had failed to stimulate adequate supply and hence should not be perpetuated by setting a new contract vintage rate in the Appalachian Area.

gas are an important source of cash for undertaking additional exploration and development, activities traditionally financed through internally generated funds because of the nature of the risks involved.

Some have opposed any price increases for flowing gas without assurance that the additional revenues will actually be devoted to a search for new gas supplies and not diverted to other types of investment. The contingent escalation provisions of the FPC's decisions in the South Louisiana and Texas Gulf Coast area cases -- providing for specified increases in flowing gas rates upon specified commitments of new gas reserves to interstate pipelines -- represent a response to this position. An alternative response, rather than withholding increased rates until the reserves are discovered, is to grant the increase subject to the requirement that the resultant additional revenues be expended in an exploratory program over and above the normal level of expenditures for such activities. This type of approach was recently applied by the FPC in a decision permitting Panhandle Eastern Pipe Line Co. to "spin off" its production properties to an affiliate and permitting the affiliate to sell Panhandle the same gas at rates higher than Panhandle's previous cost of service allowance. The Commission required that the entire revenue difference be spent on a program to explore and develop new gas reserves for Panhandle's system over the next five years.[1/]

All of these measures present difficulties, but they all represent ways for increasing the supply of funds available for exploration and

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1/ FPC Opinion No. 626, in re Panhandle Eastern Pipe Line Co. and Pan Eastern Exploration Co. (CP71-237 et al.), issued September 20, 1972.

development. As with other possible regulatory changes, the level of new reserves which would be forthcoming is impossible to ascertain with any degree of precision.

3. Other Measures

Still other measures which either have been taken, or could be taken, by the FPC to induce the eliciting of new gas supplies include: (a) permitting advance payments by pipelines to producers for exploration and development, subject to certain qualifications; (b) waiving refunds of excess revenue collections determined to be owed by producers to pipelines; and (c) encouraging participation in exploration and development activities by small producers, pipelines and distributors.

The FPC first adopted a policy of permitting pipelines to make advance payments to producers (and to recover such advances in their rates) in October 1970. At that time the Commission authorized advance payments for purposes of exploration, lease acquisition, development and production of gas. A year later, the FPC decided to terminate recovery in rates of advances related to exploration and lease acquisition, on the ground that such advances seemed merely to be causing increased expenditures without a proportionate increase in supply, but to continue this treatment for advances related to development and production through December 31, 1972. At the present time, the advance payment question is under review to determine whether the current practice should be terminated, extended either in its present form or expanded so as again to permit advances for exploration and lease acquisitions.

Data collected by the Commission in connection with the above review reveal that advance payments during the period October 2, 1970 through November 10, 1971 -- the period when advances were allowed for exploration and lease acquisition, as well as for development and production -- are estimated to have resulted in the commitment of over 18 trillion cubic feet of proven reserves to the pipelines making the advances, as compared with only about 800 billion cubic feet during the subsequent period of more restricted rate treatment.[1/] These data appear to indicate that the advance payment program has made substantial additional reserves available to interstate pipelines. However, some pipelines and producers question whether the program has elicited any new reserves which would not have been brought forth in any event, whether the payments are not merely a circuitous method of responding to supply and demand factors (rather than raising the field price), whether the financial resources of pipelines are sufficient to permit advance payments plus the construction of necessary transmission capacity and the development of supplemental supplies, and whether the effect of the program has not merely been to raise rates to consumers by millions of dollars without any assured benefit. As to the last point, it should be pointed out that the FPC now requires repayment of the advances either from production or through other means if no production results. On balance, while the efficacy of the advance payment program is difficult to assess, it has provided funds to

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1/ Over the period October 2, 1970 through August 31, 1972, some 22 pipelines made advance payment commitments totalling $1.25 billion (43% for activities in Canada and Alaska) and actually advanced $720 million during that time.

spur exploration and development beyond the level which might have otherwise occurred.

Waiver of refunds has also been employed by the FPC to encourage additional funds to be plowed into exploratory efforts.[1/] The most notable examples were in the South Louisiana and Texas Gulf Coast area proceedings where the Commission provided that producers would receive a credit of 1¢/Mcf against refund obligations determined in those cases for each additional Mcf of new gas reserves committed to jurisdictional sales over roughly the following five years. This refund credit procedure is tied to results, not just to expenditures for exploration and development. The procedure was worked out in negotiations leading to settlement of the South Louisiana proceeding and was agreed to by all parties (except the few which are now contesting the FPC's acceptance of that settlement in the courts). In the South Louisiana case, refund obligations were established at roughly $150 million which, to be worked off, must be expended on successful ventures to develop additional reserves in that area.

Several producers have petitioned the FPC for special relief from refund obligations in other cases. One large producer, for example, presently seeks permission to apply some $37 million of refund monies owing under the Commission's decision in the Hugoton-Anadarko area case to explore

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1/ As discussed in a previous chapter, the FPC over the years has ordered millions of dollars of refunds pursuant to determinations reducing producer rates. In several cases, however, actual payment of the refunds was stayed pending court litigation. Also, many producers have been ordered to retain refund amounts pending FPC determination as to their ultimate disposition, i.e., whether the receiving pipelines intended to keep the sums involved or pass them on to their customers.

for new gas reserves in that area over a five-year period. The FPC has not acted on this petition, nor has it adopted any general policy respecting petitions of this type.

While the waiver of refunds involves a number of equitable considerations, refund monies nevertheless are a potential source of supplemental funds to be directed to exploratory ventures holding promise for future supplies. It would seem that, on balance, consumers would benefit far more by application of the funds in question to a search for additional gas reserves than by receiving the refund monies either in cash or as a credit to their gas bill. Under the second alternative, the amount received by each customer would be minimal.

With respect to wider participation in gas exploration and production, the FPC has already largely exempted small producers from regulatory requirements (except certain limited filings) in an effort to stimulate greater activities by this group[1/] (FPC Order No. 428, issued March 18, 1971.) It has also sought to encourage greater pipeline production by allowing area rates to pipelines and pipeline affiliates for gas produced from leases acquired after October 7, 1969. (FPC Opinion No. 568, issued October 7, 1969.) The fact that pipeline production has not increased since this decision undoubtedly reflects in part the inadequate incentive provided by present area rates for all producers.

The question of distributor participation in gas exploration and development has not yet been ruled on by the FPC. Several large distributors have established subsidiaries to search for gas, and some

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1/ As noted in Chapter IV, this exemption was reversed by the U.S. Court of Appeals for the D.C. Circuit on December 12, 1972.

have discovered reserves which they seek to have transported by an interstate pipeline to their service area. One case presenting this situation is now before the Commission.

Unquestionably, distributor investment in exploration activities represents an additional source of risk capital beyond that which pipelines and producers appear willing to commit at the present time. Moreover, because of vested interests of distributors in maintaining service to retail markets, their motivation to develop gas for interstate consumption is perhaps more immediate than that of independent producers who will sell to intrastate markets if that alternative is more rewarding economically. On the other hand, there is opposition by those who fear that a proliferation of efforts by large distributors to explore for, and thereby to preempt gas supplies for their own use, would lead to an inequitable distribution of gas among different regions and consumers of the nation. Another opposing argument is that distributor participation in the production business would result in widespread integration of these two traditionally separate segments of the gas industry, thereby reducing the motivation of distributors to check unreasonable attempts to increase the price of gas at the wellhead. On balance, at least at the present time, these possible disadvantages may not outweigh the positive benefit of increased funds available for exploration and the consequent promise of expanded gas supplies.

4. <u>What EPA Can Do</u>

At some point in the future, EPA might consider a statement of position regarding various regulatory approaches which could be taken by

the FPC in an effort to increase wellhead supplies of gas. As identified above, some of the possible means open to the FPC at this time include (a) establishment of higher gas prices reflecting market value and other pertinent economic considerations; (b) flexibility in applying the optional certificate procedure; (c) relief from refunds, subject to use of refund monies in exploration for gas; (d) expansion of the advance payment program; and (e) distributor participation in gas exploration operations. However, in the event EPA should decide to support any of these measures -- all of which involve higher prices to consumers to increase supply -- this should not be done without thorough prior evaluation of their impact on transportation, distribution and consumption of gas.

In adjudicatory proceedings at the FPC, any expression of views by EPA would require formal intervention. The degree to which EPA might wish to participate in such proceedings will depend on budgetary and manpower considerations, as well as an assessment of the benefits to be gained. In FPC rulemaking matters, formal intervention is not required. EPA has already commented in one important rulemaking matter (regarding the optional certificate procedure), and it may desire to do so in others.

F. Acceleration of Offshore Leasing

Clearly, one of the most obvious means for encouraging expansion of natural gas supply is to accelerate, and regularize, the leasing of offshore lands. As noted at an earlier point in this chapter, the Potential Gas Committee estimates 20% of total U.S. potential gas reserves to underlie OCS lands (excluding Alaska), while the Geological Survey estimates

the OCS share at 40% (including Alaska). Yet only about 1% of the federal offshore area (including Alaska) has been leased. Moreover, the U.S. Continental Shelf out to 200 meters is reachable by technology now at hand. These considerations all point unmistakably in the direction of greater offshore leasing.[1/]

Delays in federal offshore leasing in the past have been unfortunate. Oil and gas lease sales in the 1960's were sporadic, with the result that promising drilling prospects for the industry did not become available as fast as they might have with a more regular schedule. The response of the industry to those sales which were held gives every indication that additional leasing would have been as favorably received. For example, in every general lease sale held by the Interior Department beginning in 1967, total bonus bids to the U.S. Government exceeded $500 million. One sale in late 1970 brought a record high total bonus of nearly $850 million.

Interior has recognized the need for an accelerated leasing program and currently plans two general lease sales annually, encompassing 300,000 - 600,000 acres each, over a five-year period in the Gulf of Mexico. Some delay in these plans has already been caused by court litigation over the adequacy of an Interior Department environmental statement. At a minimum, the five-year schedule should go forward with every effort to avoid or minimize further delay. Moreover, Interior might consider additional sales if the industry appears willing and able to explore and develop further

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1/ An acceleration of offshore leasing is not exclusive of the need for higher gas prices to induce exploration and development.

acreage at a faster rate. Alternatively, it has been suggested that the offering of larger amounts of acreage in each sale -- perhaps one million acres -- would enable development of more prospects and hopefully greater reserves.

The Gulf of Mexico is a logical point of principal focus in Interior's current leasing plan since potential gas reserves in OCS lands off Louisiana and Texas are estimated (by the Potential Gas Committee) at 99 trillion cubic feet and 53 trillion cubic feet, respectively -- or, together, well over 60% of the total offshore potential (excluding Alaska). Offshore Louisiana, in particular, is already a prolific producing area, and most of its undiscovered potential is classified either as "probable" (extensions of existing fields) or "possible" (new field discoveries in previously productive formations). Estimated potential reserves for offshore Texas are primarily in the "possible" category. In addition, the OCS area off Florida, Alabama and Mississippi -- where one sale is contemplated by Interior in the five-year period -- is estimated to contain potential reserves of 39 trillion cubic feet, although all classified as "speculative" (new field discoveries in formations or provinces not previously productive).

Development of the potential in the Gulf of Mexico areas would obviously make a significant contribution toward increasing the nation's domestic resource base in both gas and oil. At the same time, efforts should also go forward to enable leasing in the Atlantic and Pacific OCS areas, and in the Gulf of Alaska, at the earliest possible time.

From the standpoint of location, the Atlantic OCS -- estimated by the Potential Gas Committee to contain 36 trillion cubic feet of potential gas reserves -- is an obvious source of providing substantial supply increases for the East Coast, already heavily dependent on imports of foreign oil and likely to become also dependent on imports of foreign gas (LNG) in the future. While East Coast states will benefit from the development of potential reserves in the Gulf of Mexico, they must share that potential with other areas of the country which rely on Gulf Coast sources for much of their gas supply. By contrast, all of the Atlantic OCS potential would presumably be available for local East Coast markets. Also, assuming the 40 trillion cubic feet upper limit of Interior's estimate of the gas reserves to be developed by its current five-year leasing schedule in the Gulf of Mexico, the total reserve potential of these OCS lands will be substantially drawn down rather quickly. All of these factors make the leasing of the Atlantic Outer Continental Shelf, assuming appropriate environmental safeguards, imperative.[1/]

In offshore California, leasing was halted by the major oil spill occurring in January 1969, and further drilling on some 35 leases granted prior to that time has been suspended. Interior's authority to order suspension of operations is now in the courts. Thus, the situation is uncertain in California at the moment. However, the same basic considerations dictating the leasing of Atlantic OCS lands also favor a

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1/ In a report dated November 1971, the U.S. Geological Survey concluded that the Atlantic Continental Shelf offers good possibilities for oil and gas production, especially gas. Geologic Framework and Petroleum Potential of the Atlantic Coastal Plain and Continental Shelf, Geological Survey Professional Paper No. 659.

resumption of leasing of the California OCS and extension of this leasing, assuming sufficient industry interest and favorable geological data, to other Pacific Coast offshore areas. Potential gas reserves, estimated at some 11 trillion cubic feet for the Pacific OCS, represent an obvious source of additional clean-burning fuel for these states, especially California. It should also be noted that the Pacific states are not connected by pipeline to Gulf Coast sources of supply and hence, lacking a means of transportation, cannot benefit from gas resources discovered in the Gulf of Mexico.

It is, of course, understood that OCS leasing should go forward only under stringent environmental safeguards. The danger of oil spills can never be entirely eliminated. However, regulations and enforcement of standards to prevent oil spills are stronger today than ever before and also are under constant review to identify possible improvements. Among other things, all offshore operators on federal lands are required to submit operating plans for approval by the Geological Survey, to install a wide variety of safety devices and to provide for standby pollution control equipment.

The efforts being taken by the Interior Department to require and enforce strict precautionary measures, and the fact that reasonably safe drilling operations can be conducted on offshore lands, need repeated emphasis to the public. EPA could make a contribution here.

A corollary issue connected with offshore leasing concerns the leasing method which will best promote early and rapid exploration and development of the OCS lands. Interior's present method of awarding

leases is through cash bonus bidding, with a fixed royalty (16-2/3%) required on any ensuing production. This method has been criticized on the ground that it siphons off large amounts of capital in bonuses which might otherwise be expended on exploration and development. Another criticism is that the bidding process is restricted to larger operators able to afford the cash bonus plus finance subsequent drilling activities, thereby precluding competition by smaller operators with less financial resources.[1/] This is said to deter the widest possible participation in offshore development. Alternative methods have been suggested, the two principal ones being: (1) a deferred bonus-fixed royalty system under which portions of the bonus would be due at various times in the future; and (2) a royalty bidding system, with no bonuses.

Both of the suggested alternatives could make available large sums of capital for exploration and development that otherwise would be committed to bonus payments. However, Interior takes the position that these methods would result in less incentive for full lease development and recovery of resources. This danger is considered particularly great in the case of royalty bidding which, Interior fears, would be conducive to speculative leasing by parties with no intention of exploration and development and also to premature abandonment of leases. However, even in the case of the deferred bonus alternative, the fact of less "sunk" cost could reduce the incentive of the operator to obtain maximum production.

1/ To date, a number of smaller operators have participated in offshore leasing and exploration in joint ventures with other companies.

In testimony before the Senate Interior Committee on June 19, 1972, Assistant Secretary of the Interior Harrison Loesch defended the present cash bonus bid-fixed royalty system as the best of the possible alternatives and said Interior does not currently plan to change this system unless directed to do so by Congress.[1/]

G. Encouragement of Supplemental Gas Supply Projects

A final regulatory category for increasing the supply of gas available to U.S. markets is the encouragement of supplemental projects involving unconventional and/or foreign sources of supply. The major such sources now on the horizon[2/] are:

(1) Gas from Alaska;

(2) Gas from Canada imported by pipeline;

(3) LNG imports by ship from overseas nations;

(4) Synthetic gas reformed from liquid hydrocarbons; and

(5) Synthetic gas from domestic coal.

Two points concerning these projects bear emphasis at the outset. The first is that, despite the publicity focused on supplemental supply, the fact is that they will make only a relatively modest contribution to U.S. supply -- at least through 1980. Based on projections of the FPC

1/ Statement of Harrison Loesch, Assistant Secretary for Public Land Management, U.S. Department of Interior, before Senate Committee on Interior and Insular Affairs, on leasing and disposal policies for energy resources on public lands.

2/ Other possible sources are nuclear fracturing of tight gas-bearing formations, oil shale gasification and tar sand gasification. However, the current state of technological development in these areas is very limited. Consequently, all of these potential sources must be regarded as speculative for some years to come.

Staff, as shown above, supplemental sources -- excluding synthetic gas from liquid hydrocarbons -- are estimated to provide only 1.5 trillion cubic feet in 1975 and 4.6 trillion in 1980, representing 5% and 13%, respectively, of forecast annual demand. Assuming reformer gas availability of 0.5 trillion cubic feet in 1975 and 1.0 trillion in 1980, the percentages would rise to about 7% and 16%. Projections by the National Petroleum Council, shown above, indicate similar proportions. These calculations serve to illustrate the fact that supplemental gas sources are only that -- supplements. They in no way diminish the crucial need to stimulate increases in domestic production, the principal source for meeting gas demand for many years. At the same time, this does not mean that supplemental gas projects should be postponed. The projected gas supply deficits are such that all sources of gas supply should be pursued with urgency within the framework of national objectives.

The second factor to be kept in mind is that, unlike conventional wellhead production of domestic gas, the nonconventional supplemental sources involve a number of considerations bearing on different facets of national policy. These considerations include national security questions concerning sources of supply, balance of payments problems, and oil import restrictions. In addition, supplemental supply projects promise to be very costly to consumers -- certainly far more so than the cost of domestic gas at the moment and, at least in the case of some projects, in excess of gas prices even assuming an increase in domestic gas rates to the price level of competitive fuels in the marketplace. In short, the regulatory encouragement to be given to supplemental supply sources -- which ones, to what

degree, and when -- requires a careful evaluation of a mix of interrelated factors.

As discussed in Chapter IV, concern with the problem of economic cost led the FPC to require incremental pricing for sales for resale of LNG proposed to be imported by three major U.S. pipelines from Algeria. This means that the LNG must be sold by each pipeline to its customers at the full import price plus the cost of regasification and transmission to consumer markets, rather than at rolled-in prices reflecting the average cost of all systemwide supplies (including domestic supplies from the Southwest and gas imported from Canada). The degree to which the FPC will apply incremental pricing concepts to other high cost supply supplements in the future will have an important bearing on their marketability in the U.S.

The incremental pricing issue is complex. However, it is vital that the issue be understood, and it is recommended that EPA take no position until the matter has been fully explored. The incremental price conditions imposed by the FPC in the El Paso Algeria case are of a precedent-setting nature in that they could lead to a substantial alteration of pricing practices (i.e., rolled-in pricing) followed by the pipeline industry to date. If the incremental pricing principle can be concluded to be in the public interest for the El Paso Algeria LNG project, then it is equally applicable to other "supplemental" gas supplies (reformer gas, coal gas, gas from Alaska and Canada, additional LNG imports), as well as to new domestic supplies priced higher than the existing rolled-in (average) price of gas delivered from the Southwest.

A shift to incremental pricing consistently applied in the future to all new gas supplies priced higher than the rolled-in average of existing gas supplies would create administrative problems, but more seriously, could limit and reduce the amount of new gas supplies for U.S. markets. This is because there are only limited markets which will be prepared to incur the risk of contracting and then selling supplemental gas supplies at a multiple of the historically prevailing gas prices. Such an abrupt change would be in direct contrast to an orderly restructuring of the gas industry which is in a serious state of disequilibrium at this time because of the supply shortage.

These end results could be detrimental to EPA's pursuit of an enhanced supply of gas. It should be kept in mind that gas pipelines and distributors seek higher cost supplemental supplies because of the failure of domestic supplies to meet existing requirements. The forepart of this chapter speaks to ways in which these adverse domestic supply trends could be reversed, but inevitably with a substantial time lag. Furthermore, there is no way to predict how responsive new domestic gas supplies will be to the incentive of higher field prices. On this basis, gas pipelines have sought supplemental supplies, and have been encouraged to do so by government.

In most instances, these supplemental supplies will be needed to maintain current demand levels and provide gas pipelines and their distributor-customers an opportunity to up-grade their markets away from interruptible service to higher priority service, by adding additional storage. Yet, to incrementally price supplemental supplies creates the

risk that only the larger distributors would be prepared to incur the risk of passing on the cost to the consumer in such an abrupt fashion. On this basis it would seem advisable at this time for pipeline systems to acquire the supplemental gas supplies because of (1) their larger market systems, (2) their ability to command the capital needed to mount the type of project needed to recognize economies of scale and (3) their ability to roll in these higher gas costs for the purpose of pricing supplies for resale to their distributor-customers. In this way, an orderly method may be provided for a transition from the current supply-demand imbalance to an orderly increase in supply of gas which would be available to meet at least moderately increasing demand.

1. Gas from Alaska

Alaskan gas emerged as a significant source of possible supply for markets in the Lower 48 States with the major oil find by Atlantic Richfield Co. and Humble Oil & Refining Co. in the Prudhoe Bay area of the North Slope in 1968. This find also resulted in the discovery of large volumes of gas associated with or dissolved in the oil.

Gas reserves in the Prudhoe Bay area are currently estimated at 26 trillion cubic feet, comprising about 84% of Alaska's total proven reserves at the end of 1971. None of this gas, however, can be made available until the oil with which it is associated can be produced and marketed. Delays encountered in obtaining the necessary regulatory approvals for the proposed oil pipeline from the North Slope to Valdez in southern Alaska are well known and require no elaboration here.

Extensive studies are presently being conducted with respect to transportation of North Slope gas via pipeline through the Mackenzie Delta corridor in the Northwest Territories into Alberta, and from there to U.S. markets. At one time, a North Slope gas pipeline was under study by three separate groups: (a) the Mountain Pacific Project -- which contemplated the construction of a pipeline system extending from the North Slope through the Fort Liard region of the Northwest Territories into British Columbia, with transportation ultimately to Pacific Coast markets as far south as Los Angeles; (b) Gas Arctic Systems Group -- which proposed a 1,550-mile line to connect the Prudhoe Bay area with an extension of Alberta Gas Trunkline's system in Alberta, with gas then to be made available to U.S. West Coast and/or Midwest markets through interconnection with existing pipeline systems; and (c) the Northwest Project Study Group -- which contemplated a 2,500-mile line from Prudhoe Bay to the international boundary near Emerson, Manitoba (presently a major export-import point for Canadian gas). The Canadian Government, however, has made clear that it will permit only one pipeline through Canada from the North Slope. The latter two groups subsequently merged to form one group (the Gas Arctic-Northwest Project Study Group). This group now has 19 participants, including the two major distribution systems serving the State of California.[1/]

1/ The 19 participants include seven major U.S. pipelines or gas distribution systems (Michigan Wisconsin, Natural Gas Pipeline, Northern Natural, Texas Eastern, Columbia System, Pacific Gas & Electric, and Pacific Lighting), two Canadian pipelines (Trans-Canada and Alberta Gas Trunk Line), three U.S. producing companies (Atlantic Richfield, Humble Oil and Standard of Ohio), three Canadian producers (Imperial Oil, Shell Canada and Gulf Canada), one Canadian distributor (Union Gas Co.), The Canadian National Railway, the Canadian Pacific Railway and Canadian Development Corp.

Target dates for the Gas Arctic-Northwest Project are presently mid-1973 for filing initial requests for authorizations in Canada and the U.S., January 1976 for commencement of construction, mid-1978 for commencement deliveries, and 1980 for full throughput deliveries (about 3.5 billion cubic feet per day, or 1,278 billion cubic feet per year).[1/] In addition to Alaskan gas, the proposed line would also transport Canadian gas developed in the Mackenzie Delta area now under active exploration.

More recently, on December 4, 1972, El Paso Natural Gas Co. announced the commencement of studies to determine the feasibility of a gas pipeline from the North Slope to a port in Southern Alaska where the gas would be liquefied and transported by tanker to the West Coast. This is the first publicly announced proposal for a gas pipeline through Alaska rather than Canada. El Paso estimates that the cost of such a project, including facilities to liquefy and transport LNG to the West Coast, would be comparable to the cost of an all overland pipeline.

From the standpoint of national security and balance of payments, Alaskan gas has considerable advantages over some other possible sources of supplemental supply. While export and import authorizations would be required in the case of a line through Canada, these would not seem to pose an insuperable barrier, although accommodations with the Canadian and Alberta Governments would undoubtedly be necessary. In the case of a line through Alaska, the need for such accommodations would be avoided.

1/ Speech of Wilber H. Mack, Co-Chairman of the Gas Arctic-Northwest Project Study Group, before the Gas Men's Round Table, Washington, D.C., August 1, 1972. Mr. Mack remarked that the described schedule may be "somewhat optimistic."

From a cost standpoint, however, the proposed Alaskan-Canada gas pipeline -- or the El Paso project, assuming a roughly comparable cost -- would be one of the costliest pipeline projects ever undertaken. Total project capital investment is presently estimated in the range of $5 billion, excluding any facilities south of the international border. Transportation costs to U.S. markets -- excluding the cost of gas in the field -- are estimated in the range of 80¢ to $1.00/Mcf or more. Adding an assumed wellhead price of -- say -- 35¢, the delivered cost of Alaskan North Slope gas to U.S. markets would be no less than $1.10/Mcf and probably nearer to $1.35/Mcf, or higher. This is more than three times the average city gate cost of gas delivered to major Midwest and California market areas in mid-1972.

Moreover, while the North Slope of Alaska is considered the predominant source for augmenting gas supplies to the Lower 48, substantial gas potential is also believed to exist in the southern part of the state, especially the Gulf of Alaska. As of December 1971, proved gas reserves in South Alaska -- located primarily in the Kenai Peninsula -- amounted to slightly more than 5 trillion cubic feet. Of the 153 billion cubic feet of gas produced in Alaska in 1971, approximately two-thirds was utilized locally and 51 billion cubic feet was shipped as LNG to Japan.

Interest has been expressed by Pacific Lighting Corp. in importing LNG from the Kenai Peninsula to markets in Southern California. A tentative plan contemplates import of 250,000 MMBtu per day initially, ultimately increasing to 750,000 MMBtu per day. The cost of initial volumes delivered to the Los Angeles city gate has been estimated at about

$1.00/MMBtu.[1/] This cost would undoubtedly be cheaper if it were not for the Jones Act, which requires ships operating solely within U.S. waters to be built in U.S. shipyards and manned with American crews. It has been estimated that the cost of using domestically built and manned vessels will add 6¢ to 8¢/Mcf to the cost of LNG moving by tanker from Alaska to Southern California (Oil and Gas Journal, January 3, 1972). This differential to consumers could be reduced or eliminated if subsidies were available to construct and operate U.S. ships to transport LNG in interstate commerce. However, the National Maritime Act of 1970 -- which expanded the U.S. maritime subsidy program -- failed to provide for subsidization of LNG tankers engaged in trade between U.S. ports.

However, even if subsidies were available, the cost of Alaskan LNG delivered to Los Angeles -- assuming a range of 92¢ to 95¢/MMBtu -- would still substantially exceed the cost of domestic gas produced in the Southwest and delivered to Southern California.

2. Pipeline Imports from Canada

In 1971, the U.S. imported 911 billion cubic feet from Canada, with most of this volume originating in the Province of Alberta. Assuming continuation of the present Canadian market protection policies of the National Energy Board (described in Chapter IV), there seems little likelihood of

1/ Submission by Pacific Lighting Corp. to Office of Emergency Preparedness, January 8, 1972.

any substantial increase in imports from Canada until sufficient reserves are developed in frontier regions to support new gas export projects.[1/]

Exploratory activity -- financed in part by advance payments from U.S. pipelines -- is currently proceeding in three frontier areas: the Mackenzie Delta in the Northwest Territories, the Arctic Islands, and the Sable Island area off Nova Scotia. Discoveries described as "significant" have been announced, but without disclosure as to the magnitude of the reserves. At present, there is no way to transport gas from these frontier areas to consuming markets. However, as noted above, Mackenzie Delta gas would likely be transported along with North Slope gas via the proposed Gas Arctic-Northwest Project,[2/] assuming this project is eventually effectuated.

Gas from the Arctic Islands of Canada is more uncertain, although about one-third of the 25 to 30 trillion cubic feet of reserves necessary to justify a pipeline is estimated to be already proven. Also, it was announced last June that a preliminary survey will be conducted to evaluate a route for transporting Arctic Island gas to markets in eastern Canada and the U.S. Nevertheless, supplies from this area seem unlikely to be available to consuming markets for at least another ten years.

1/ Whereas proved reserves in Canada at December 31, 1971 were estimated at 55.5 trillion cubic feet (less than estimated proved reserves of 75 trillion cubic feet in South Louisiana), potential gas reserves in Canada have been estimated at 725 trillion cubic feet, largely in frontier areas.

2/ Under advance payment contracts with Michigan Wisconsin Pipe Line Co. and Natural Gas Pipeline Co. of America, Imperial Oil Ltd. is obligated to give the two pipelines first call on 10 trillion cubic feet out of the first 12 trillion of reserves developed by it in the Mackenzie Delta. The initial price for this gas in the field has been reported at 32¢/Mcf, plus definite and indefinite escalations. (Oil & Gas Journal, July 24, 1972.)

As to offshore Nova Scotia gas, Texas Eastern Transmission Corp. -- which has contracted to advance a total of $24 million to a Canadian subsidiary of Mobil Oil Corp. -- outlined plans in an FPC proceeding (concerning the rate treatment of the advance) to move up to 660,000 Mcf/d (or 241 billion cubic feet per year) through a large-diameter pipeline from the Sable Island area to Boston, Massachusetts. The cost of the 775-mile pipeline was estimated at about $320 million and the unit cost of transportation at about 26¢/Mcf, both in 1971 dollars. These estimates appear conservative, and again this gas does not seem likely to be available for several years, assuming that a viable project can in fact be developed and all necessary regulatory authorizations on both sides of the border obtained. It can be reasonably anticipated that the Canadian Government would require at least a portion of the gas to be retained for markets in eastern Canada.

Thus, it does not appear that Canadian gas will be available in substantial quantities -- beyond presently authorized import volumes -- during the balance of the current decade to alleviate U.S. supply shortages. To the extent that frontier area gas reserves are developed, transportation facilities are constructed and Canadian export licenses granted, such gas could be considered as a relatively secure source of supply. However, balance of payments problems would arise. Also, as in the case of Alaskan gas, the same high delivered costs pertain -- with the possible exception of offshore eastern Canada gas which possibly could be delivered to New England markets for less than $1.00/Mcf.

3. LNG Imports

The importation of LNG began in 1968 for peak shaving purposes on a short-term basis. Since that time, various New England distributors, and Texas Eastern Transmission Corp., have been authorized to import one or more shiploads from Algeria or Libya for limited periods (usually not exceeding six months) at rates up to $1.70/Mcf.[1/]

The first applications to the FPC for long-term imports of LNG were filed in 1970. One application involved a project by Distrigas, a subsidiary of Cabot Corp., to import approximately 15.4 billion cubic feet annually from Algerian sources for a period of 20 years beginning in 1971 to help meet peak shaving needs of distributors in the New England and New York City areas. A second proposal concerned the importation of one billion cubic feet of LNG per day -- or 365 billion cubic feet per year -- by subsidiaries of the Columbia Gas System, Consolidated Natural Gas Co. and Southern Natural Gas Co. from El Paso Algeria Corp. over a 25-year period beginning in 1975 for base load needs. Both projects were certificated by the FPC in 1972; pertinent details of these authorizations, and some of their implications for future LNG projects were described in Chapter IV.

In addition, two other long-term LNG import proposals have been filed in the FPC -- one by Eascogas LNG Inc. to import varying quantities up to approximately 237 billion cubic feet annually from Algeria for 22 years for base load use primarily by Algonquin Gas Transmission Co. in New England and by Public Service Electric & Gas Co. in New Jersey, and the

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1/ LNG has also been imported from Canada into New England by truck on a spot basis at rates up to $1.94/Mcf.

other by Distrigas to import an additional 45 Bcf annually from Algeria for 20 years (thus expanding its original project by nearly three times) -- while several other prospective projects have been announced in the press. The prospective projects reveal a considerable diversity of supply source, as indicated in Table V-11 summarizing the various long-term LNG proposals announced to date (or reported to be under consideration).

Even assuming effectuation of all of the announced projects, it is unlikely that they will proceed according to current schedules in view of the length of time required to obtain necessary governmental authorizations and to build the extensive facilities involved in any large-scale LNG import project. The FPC Staff projects LNG import volumes of 0.3 trillion cubic feet in 1975, rising to 2.0 trillion in 1980, 3.0 trillion in 1985 and 4.0 trillion in 1990. The National Petroleum Council projects 0.2 trillion cubic feet in 1975, 2.1 trillion in 1980 and 4.0 trillion in 1985.

From a regulatory standpoint, the importation of LNG on a large scale for base load purposes poses national security problems, balance of payment problems and cost problems. With regard to national security, the bulk of the world's estimated gas reserves -- exclusive of North America -- are located in the Soviet Union, the Middle East and North Africa. Each of these area sources could be interrupted in the event of international political or military problems. In time, the consequences of any such interruptions can be alleviated in part by achieving a maximum diversity of LNG sources. Also, the large amount of capital investment required by the exporting countries in production, pipeline, liquefaction and

FILED AND PROSPECTIVE LNG IMPORT PROJECTS

Principal Importing Company (or Companies)	Origin of LNG	Destination of LNG	Annual Volume (Bcf)	Announced Startup Date	Status in FPC
Distrigas Corp.	Algeria	Boston, Mass. Staten Island, N.Y.	15.4	1971[a]	Approved
Columbia LNG Corp.		Cove Point, Md.	109	1975	Approved
Consolidated System LNG	Algeria	Cove Point, Md.	128	1975	Approved
Southern Energy Co.		Savannah, Georgia	128	1975	Approved
Eascogas LNG Inc.	Algeria	Providence, R.I. Staten Island, N.Y.	237[b]	1975	Filed
Distrigas Corp.	Algeria	Boston, Mass. Staten Island, N.Y.	45	1975	Filed
Consolidated System LNG	Algeria	Cove Point, Md.	55		
Phillips Petroleum Co.	Nigeria and/or North Sea	East Coast	365		
Shell Oil Co.	Nigeria	East Coast	237	1978	
Amoco International Oil Co.	Trinidad	Gulf Coast	164		
	Venezuela[c]		475	1975	
Pacific Lighting Corp.	Alaska	California	146	1975	
Pacific Lighting Corp.	Australia	California	183	1978	
Pacific Lighting Corp.	Indonesia	California	365	1976	
	Iran[d]		438	1976	
Tenneco Oil Co. Texas Eastern Transmission Brown & Root	[e] USSR	East Coast	1,095	1980	
El Paso Natural Gas Co. Occidental Petroleum Co. Bechtel Corp.	[e] USSR	West Coast	365	1980	

a/ A first shipload was delivered in 1971, but further deliveries have been delayed due to liquefaction plant startup difficulties in Algeria.
b/ Projected delivery volume in fourth through twentieth year of 22-year term, less in other years.
c/ The Venezuelan Government is reportedly pursuing plans for two LNG plants producing about 1.3 billion cubic feet per day. A bid for tanker construction by a U.S. company has been submitted to the Venezuelan Government. The target date for first LNG production is mid-1975.
d/ The Iranian Government has announced a joint project with International Systems and Controls Corp. The LNG would be supplied to the U.S., South America and Japan.
e/ Projects under negotiation. No agreements have been reached.

Source: FPC Bureau of Natural Gas National Gas Supply and Demand, 1971-1990, Staff Report No. 2, pages 67-72; press articles.

other equipment necessary to bring about an LNG project is another factor tending to lessen the danger of supply cutoff.[1/]

On the other hand, a supply interruption over any significant period of time could cause severe problems for particular pipelines or distributors which become heavily dependent on imported LNG. In the El Paso Algeria case, for example, the LNG imports are estimated to account for a substantial portion of the total future gas supply of the three U.S. purchasing pipeline companies -- 9.1% for the Columbia Gas System, 14.3% for Consolidated Natural Gas Co. and 20.1% for Southern Natural Gas Co. To mitigate the impact of a possible cutoff of LNG, the Defense Department has suggested that the FPC adopt rules limiting the volume of overseas LNG taken by any one distributor for firm (as opposed to interruptible) use to the percentage of total system gas not considered critical, requiring large firm gas users to have standby facilities for alternate fuels or else be converted to an interruptible basis, or possibly requiring larger storage facilities or emergency sources of domestic gas for distributors using substantial amounts of overseas LNG.[2/]

These views raise the question of whether LNG imports should be subjected to overall import restrictions. No restrictions apply at present. However, it is a valid inquiry whether it is sensible to allow

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1/ In connection with the El Paso Algeria project to import one billion cubic feet daily, the U.S. State Department argued that the Algerian Government's ownership of all facilities in Algeria necessary for the project will give it a major financial interest in continued sales, thus enhancing security of supply.

2/ Letter dated July 23, 1971 from Defense Department to FPC in re Columbia LNG Corp. (CP71-68 et al.).

the importation of LNG without limitation while at the same time controlling the importation of crude oil at lower energy equivalent prices.

As to balance of payments problems, there is no doubt that purchase of increasing gas volumes from foreign nations would aggravate the nation's foreign trade balance deficit. The same problem exists for oil imports, which could substitute for some of the proposed LNG imports, except that imported oil -- to the extent it remains cheaper on an energy equivalent basis than imported gas -- would have a lesser impact on the deficit.

With respect to costs, the long-term LNG projects filed to date in the FPC already reflect a rising cost trend which may be expected to continue as a result of both inflationary factors and pressures for higher prices by the exporting countries. Specifically, the first Distrigas project involved a delivered LNG price of 68¢/MMBtu (plus fixed annual escalations of 0.6¢/MMBtu over the 20-year life of the contract), including 34.5¢ per million Btu (with 0.3¢ annual escalations) to be paid to Sonatrach. The second Distrigas project contemplates a delivered LNG price of 73.9¢ per MMBtu (plus certain percentage escalations and other adjustments beginning in 1973), including 43.5¢/MMBtu -- escalating 1.5% each year -- to be received by Sonatrach. Thus, in the space of about two years, the total base price of Algerian LNG to Distrigas rose by about 8%, while the rate negotiated by Sonatrach climbed 26%.

Similarly, the estimated costs of Algerian LNG delivered to Columbia LNG and Consolidated at Cove Point, Maryland and to Southern

Natural at Savannah, Georgia are 77¢ and 83¢/MMBtu in 1976;[1/] these costs include a base price to Sonatrach of 30.5¢/MMBtu, of which 80% is firm over the 25-year contract term and the remainder is subject to change in accordance with certain Bureau of Labor Statistics price indexes. By comparison, the estimated cost of LNG delivered by Eascogas to Providence, Rhode Island and Staten Island, New York is 89¢/MMBtu in the first year of regular deliveries (1975-1976), including a price to Sonatrach of 45.75¢/MMBtu plus annual escalations of 1.5% each year.

No price details are available for the other LNG projects, but it is unlikely that they would entail lower costs than those described above. Certainly, LNG imported from Iran, Indonesia, Australia and the USSR promises to be costly.

In addition to augmenting the nation's supply of gas, LNG imports offer a collateral benefit to the United States in the form of revitalizing its shipbuilding industry. At the present time, it is contemplated that six of the nine LNG tankers required for the El Paso Algeria project and at least three of the five tankers required for the Eascogas project will be constructed in U.S. shipyards. Construction differential subsidies totalling about $140 million have already been awarded by the Maritime

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1/ As noted in a previous chapter, the FPC imposed fixed import prices at the 77¢ and 83¢ cost levels estimated by the Applicants in the first full year of deliveries, thereby precluding the operation of cost adjustment provisions in El Paso Algeria's contracts. On rehearing, the FPC retained the fixed import ceilings but provided that filings could be made to recover additional costs shown to serve the future public convenience and necessity.

Administration for six of these ships.[1] In addition, the Maritime Administration predicts that up to 60 LNG carriers could be constructed in American yards by 1980, thus providing a major boost to U.S. employment and shipbuilding capabilities. On the other hand, some question the wisdom of constructing a large fleet of LNG tankers with U.S. subsidies for the purpose of importing a fuel which costs more than other imported fuels and substantially more than domestic gas.[2]

The capital requirements of LNG projects are another factor to be considered. The El Paso Algeria project is now estimated to require a capital investment of $1.7 billion for deliveries of one billion cubic feet per day, including about $628 million for facilities in Algeria. Under present plans, a large part of the Algerian facilities would be financed in the United States -- by the Export-Import Bank and by a consortium of U.S. banks. Conservatively assuming an average capital investment of $1 billion per one billion cubic feet of daily capacity (or $1 per cubic foot per day), this equates to $6,000 per barrel of oil per day.

4. Synthetic Gas Reformed from Liquid Hydrocarbons

Another potentially important source of supplemental gas is synthetic pipeline quality gas (SNG) reformed from liquid hydrocarbons. This source, however, is heavily dependent on imports of oil or oil products. As such, changes in the present oil import program are critical to the

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1/ The subsidies cover the estimated difference in cost between building the ships in an American as opposed to a foreign shipyard.

2/ E.g., address of James Akins, Energy Director of the State Department, to the Institute of Gas Technology in Chicago on November 16, 1972.

magnitude of SNG which will become available in the future.

Over 40 different projects to synthesize gas from liquid hydrocarbons have been announced during the past year and a half. Most are in the investigation or planning stage; a few which are based on domestic or quota-free LPG feedstocks (such as Canadian ethane and propane) and do not require FPC authorization are under construction; five have been filed with the FPC; and several have been submitted to the OEP with requests for waiver of the MOIP to permit importation of foreign feedstocks. The various projects are summarized in Table V-12, together with estimated capital costs, unit output costs, targeted completion dates and present status.[1/]

OEP has estimated that base load SNG proposals submitted to it to date would, if implemented, result in the production of 1.2 trillion cubic feet per year of synthetic gas by 1975 and 2.2 trillion per year by 1980.[2/]

In general, reformer gas projects are of two types: those based on conversion of naphtha or light hydrocarbon liquids to synthetic gas, and those based on use of crude oil as the original feedstock. The majority of the projects announced thus far fall in the former category. Several commercial techniques, based on technology developed in the United Kingdom, West Germany or Japan, are currently available for the reforming of naphtha or lighter liquids. Projects based on crude oil contemplate, for the most part, the refining of imported crude into

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1/ The information in the table is based on company estimates which are highly tentative in many instances. Also, the time framework reflected in the table does not represent a realistic picture at this time.

2/ Address by Robert E. Shepherd, Chief of Oil and Energy Division, Office of Emergency Preparedness, to Institute of Gas Technology in Chicago on November 16, 1972.

ANNOUNCED REFORMER GAS PROJECTS

Company and Location	Process	Expected Completion Date	Investment $ Million	Feedstock MBbls. Day	Feedstock Type	Feedstock ¢/Gal.	Feedstock Source	Output MMcf Day	Output Cost ¢/Mcf	Output Cost Basis	Output Purchaser	Status
Algonquin SNG, Inc. Freetown, Mass.	CRG	Oct. 1973	39.5	24.2	Naphtha	10.5	Domestic (Humble) and Foreign	120	142 180	335 days/yr. 151 days/yr.	Algonquin Gas Trans. Co.	Filed with FPC (Docket CP72-35) Examiners decision issued 3/28/72
Amerada Hess Reading, N.J.			14		Naphtha			125				Included in plans to expand other facilities, indicated to OEP
Apco Oil Corp. Eastern Pennsylvania		1974	28	28	Naphtha		Bahama Isls.	125	105-113		Columbia LNG Corp.	Notified OEP of plans
Ashland Oil Appalachia	MRG	1973	10		Light Hydrocarbons		Canada	49			Iroquois Gas	Indicated in press
Baltimore Gas & Electric Baltimore, Md.	CRG	1973			Naphtha			125				Indicated in press
Boston Gas Co. Everett, Mass.	MRG	1973	4.5	10	Propane		Domestic	40	130	Seasonal Operation		Under construction. May switch to naphtha
Brooklyn Union Gas Co. Brooklyn, New York	CRG	Late 1973	12-23	10	Naphtha		Domestic (Humble)	50	150-160	180 days/yr.		Construction to have begun 6/1/72
Central Illinois Light	CRG				Naphtha			60				Indicated in press
Cities Service Gas Co. Missouri		Last Q 1975	20	25	Naphtha		Domestic	125	125			Has acquired land options; indicated in Motion to File Brief Amicus Curiae (Docket CP71-68) that exhibit materials are being prepared for application to FPC
Cities Service Gas Co. Missouri (each of five plants)		1976-1980	20	25	Naphtha		Domestic and Foreign	125	125			Indicated to OEP
Coastal States Gas Producing Co. Corpus Christi, Tex.	CRG	1974-1975	25	30	Naphtha		Primarily Domestic	125	110		Trunkline Gas Corp.	Letter of intent signed by both firms. Initial price subject to adjustment in relation to posted price of crude (Docket CI72-848)
Columbia LNG Corp. Green Springs, Ohio	CRG	July 1973	37.8	86.9	NGL	7.00	Canada (Dome Petroleum)	250	112			Under construction; filed with FPC (CP72-8)
Commonwealth Natural Gas Chesapeake, Va.	CRG	Oct. 1973			NGL		Venezuela	30				Announced
Consumers Power Co. Marysville, Mich.	CRG	Early 1973	50-60	50	NGL		Canada (Dome Petroleum)	100-1973 200-1974	115-125			Under construction
Continental Oil Co. East Coast (each of two plants)		1974	30	33	LPG		Foreign	125				Under construction
Crown Central Petroleum Corp. Baltimore, Md.		1974	200	100	Crude oil		Middle East	100	105		Columbia Gas System	Indicated to OEP
El Paso Texas Gulf Coast			60	65 bbls. Conden.	Naphtha		Algerian Condensate	250		350 days/yr.		Indicated to OEP; gas would be used for Southern Division system
Felmont Oil Olean, New York		1974-1975		22.5-24	Naphtha		Foreign	95-100				Requested permission to import naphtha; startup 24 months after import allocation is received

ANNOUNCED REFORMER GAS PROJECTS

Company and Location	Process	Expected Completion Date	Investment $ Million	Feedstock MBbls. Day	Feedstock Type	Feedstock c/Gal.	Feedstock Source	Output MMcf Day	Output Cost c/Mcf	Output Cost Basis	Output Purchaser	Status
Foster Wheeler Corp. Nansemond County, Va.	CRG/ FBH		180-310	180	Crude		Kuwait	258-719	95			Fuels complex under consideration
Gasco, Inc. Honolulu, Hawaii		1975	15	2.7-1975 3.5-1980	Naphtha Naphtha		Foreign and/or Domestic	1975 - 163-187/MMBtu 1980 - 152-176/MMBtu				Indicated to OEP
Howard Oil Co. Philadelphia, Pa.		1973-1974	156	150	Crude		Middle East (Gulf Oil)	250				Site acquired; design in progress; indicated to OEP
Indiana Gas Co. Indiana					Naphtha		Middle East					Under investigation
Iroquois Gas Co. New York State					NGL, Naphtha							Indicated in press
Niagara Mohawk-Consolidated Gas Supply Oswego, New York		Late 1974			Naphtha		New Eng. Pet. Energy Refinery	125				First in a series of proposed energy refineries
Northern Illinois Gas Co. Morris, Illinois	CRG	Early 1974	50	35	NGL		Domestic (Mapco, Inc.)	100	105			Under construction
Northwest Natural Gas Portland, Oregon	CRG	1974-1975			Naphtha			50				Indicated in press
Orange and Rockland Utilities New York					Naphtha							Indicated in press
Pacific Gas and Electric Co. PG&E Service Area					Crude		Foreign					Under consideration
Panhandle Eastern Pipe Line Co. (with Amerada Hess) Illinois		1974		60	Naphtha		Foreign	125-250	120-130		Trunkline Gas Co.	Startup 15-18 months after initiation; request has been made to OEP to import 21 MMbbl./yr.
Peoples Gas Light & Coke Will County, Illinois	CRG	1974-1975	50	33	NGL		Domestic (American Oil, Union Oil of Calif.)	150	110			Announced plans to build and operate
Philadelphia Electric Co. Pennsylvania		1974			Naphtha			125				Indicated in press; company estimates 4 plants needed by 1986
Public Service E & G Livingston, New Jersey	CRG	Late 1973	30	25	Naphtha	7	Foreign	125	77			
Public Service E & G Livingston, New Jersey	CRG	1972-1973			Propane & Butane			20				Under construction
South Jersey Industries New Jersey					Naphtha			125				Indicated in press; subject to regulatory approval, financing and site selection
Tecon Gasification Co. South Plainfield, N.J.	MRG	Late 1973	140	110	Naphtha	10.25 8.71	Domestic (1/3) Foreign (2/3)	500	125			Filed with FPC (Docket CP72-100)

ANNOUNCED REFORMER GAS PROJECTS

Company and Location	Process	Expected Completion Date	Investment $ Million	Feedstock MBbls. Day	Feedstock Type	Feedstock ¢/Gal.	Feedstock Source	Output MMcf Day	Output Cost ¢/Mcf	Output Cost Basis	Output Purchaser	Status
Tenneco, Inc.					Crude and unfinished oils		Foreign					Indicated to OEP
Tenneco, Inc.		1974			Naphtha							Indicated to OEP
Transco Energy Co. Pennsylvania	Lurgi	1974-1975	85	53.5 4.2	Naphtha Propane	10.7 10.9	Foreign & Domestic Domestic	250	1.20-1.40		Transcontinental Gas Pipe Line	Filed with the FPC (Docket CP73-20)
Transco Energy Co. Eastern Seaboard		Late 1975	300	100	Crude		Middle East	460				Siting under investigation; preliminary planning accomplished; engineering in progress
Trunkline Gas Co. Midwest			60	60	Naphtha		Foreign	300	100+			Indicated in press
Washington Gas Light Co. Near Wash., D.C.		1974	15-20		Naphtha			50-60	100+	Peaking facility		Under consideration
Zapata Norness, Inc. Louisiana (each of two plants)		1975	200-250	85	Crude	5.9-7.1	Persian Gulf	400	185-105			Request made to OEP for modification of Oil Import Program to permit feedstock imports
United Gas Pipe Line Gulf Coast		1975		150	Crude		Foreign	340	95			Had indicated plans for series of plants to FPC; has acquired land options at Pascagoula, Mississippi

Source: Comments filed with Office of Emergency Preparedness.
Oil and Gas Journal, July 31, 1972.
Pipeline and Gas Journal, May 1972.
Other current articles from The Oil Daily, The Wall Street Journal, Oil and Gas Journal, and The Journal of Commerce.
FPC Dockets CP71-68, CP72-8, CP72-35, CP72-100, CI72-20, CI72-848.

naphtha and low sulfur residual fuel oil, with the naphtha then reformed by a subsequent process into SNG. At this time, there is no known commercial process available for the direct gasification of crude oil.

Considering reformer projects based on naphtha (or LPG), there are two major advantages from the standpoint of increasing gas supply. One is that plants of this type can be built in about two years, which represents a considerably shorter lead time than required for other supplemental sources of supply. Thus, reformer gas could be made available to alleviate supply shortfalls more rapidly than other alternatives. A second advantage is that the necessary capital investment is far below that entailed for base load LNG import, coal gasification or Arctic pipeline proposals. For example, compared with an assumed capital outlay of approximately $1 per cubic foot per day of capacity required for a base load LNG import project, the five reformer plant proposals filed with the FPC to date involve a capital investment ranging between about 15¢ and 34¢ per cubic foot per day of capacity. As a result, more companies could afford to enter into synthetic gas projects -- either to provide year-round supplies or seasonal supplies.

At the same time, reformer gas -- like imported LNG, Arctic gas and gas from coal -- is a costly supply supplement. For the base load projects shown on Table V-12, the estimated costs per unit of output range from 77¢ to $1.42/Mcf. For seasonal projects, unit costs are estimated in the range of $1.30 to $1.80/Mcf. These costs are highly sensitive to the cost of naphtha feedstock. Evidence submitted in the FPC with respect to the proposed Tecon Gasification and Algonquin SNG proposals indicates

that the cost of feedstock accounts for about 75% of the tailgate cost of reformer gas. It is further estimated that each 1¢ increase in the price of naphtha will increase the cost of synthetic gas output by approximately 8¢ to 9¢/MMBtu.

As to synthetic gas projects based on crude oil, lead times are estimated to be somewhat longer and capital costs higher than in the case of projects based on gasification of naphtha or lighter liquid hydrocarbons. To the extent that estimates have been made for gas product costs per unit, they are in the range of $1.00/Mcf.

The availability of feedstocks is obviously a major variable of the future supply of SNG derived from liquid hydrocarbons. Feedstock availability, in turn, depends on worldwide refinery yields and the Mandatory Oil Import Program.

Regarding naphtha, the proposed feedstock for the majority of projects under consideration at this time, a study submitted by Texas Eastern Transmission Corp. in FPC proceedings on its Tecon Gasification project concluded that the Free World supply of surplus naphtha would be more than adequate to meet total U.S. requirements for naphtha, including requirements for the Tecon plant and for other SNG projects, over the period 1970-1985. It was further concluded that the bulk of naphtha needed for manufacture of SNG would have to be derived from foreign sources.[1/] Shipments of foreign naphtha needed to meet U.S. requirements were projected at

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1/ At the present time, nearly all naphtha produced in domestic refineries is consumed in the manufacture of gasoline and military jet fuels.

425,000 barrels per day in 1975, 850,000 barrels per day in 1980 and 1,350,000 barrels per day in 1985.

Consequently, assuming the validity of the above conclusions, the naphtha reforming route would require substantial imports of a refined crude oil product to produce gas which would doubtless exceed the energy equivalent cost of crude oil for some time. In addition, this route would result in increased reliance on foreign refining capacity.

An alternative and possibly more desirable route is the importation of crude oil to produce naphtha in domestic refineries, for subsequent conversion to SNG, and low sulfur residual fuel oil. Advantages of this course of action, compared with the importation of naphtha, include (a) encouragement, rather than discouragement, of domestic refining capacity; (b) provision of two needed fuels rather than only one, with concomitant benefits of interfuel competition; and (c) the ability to use high sulfur crude oil as the basic refinery input.

In short, the encouragement of synthetic gas production, while a potentially important supply supplement, is enmeshed with many other policy questions and can not be considered from the sole standpoint of gas supply maximization.

5. Synthetic Gas from Coal

Coal gasification offers a promising and advantageous source of supplemental gas; however, significant volumes are unlikely to be forthcoming before 1980. The FPC Staff projects the availability of 300 billion cubic feet in that year.

The only commercial coal gasification process available at this time is the Lurgi process, developed in Germany some 30 years ago. Several commercial Lurgi plants have been built, mostly in Europe, and are in operation today. Lurgi gasification is particularly suitable for noncaking coals of the subbituminous or lignite type, found in large quantities in the western United States. However, a major problem with the Lurgi process, from the standpoint of attaining pipeline quality gas, is that the heating value of the produced gas is only between 400 and 450 Btu per cubic foot, far below the 1,000 Btu per cubic foot norm required for substitution and interchangeability in American gas pipeline and distribution systems. Therefore, a further methanation step is necessary to raise the heating content of Lurgi gas. This further methanation process, not yet commercially proven, is currently undergoing pilot plant evaluation.

To date, only one coal gasification project has reached a sufficiently advanced planning stage to be filed with the Federal Power Commission. This project comprises a 250,000 Mcf per day complex proposed to be constructed by El Paso Natural Gas on a 40,000 acre coal lease situated within a Navajo Indian Reservation in San Juan County, New Mexico. El Paso has established over 700 million tons of coal in this area, sufficient to support three projects of the contemplated size. The gasification plant would use the Lurgi process, plus a further methanation step. Feedstock requirements are expected to approach 8.8 million tons of coal annually. The targeted startup date for the plant is late 1976, and the cost of synthetic gasified coal to El Paso in the first full year of operation (1977)

is $1.21/Mcf.[1/] The projected capital cost of the mining, gasification, dehydration, compression and other facilities is estimated at $420 million (or approximately $1.70 per cubic foot per day of capacity).

Another proposal for coal gasification in northwestern New Mexico has been announced by a consortium of three companies -- Texas Eastern Transmission Corp., Pacific Lighting Corp. and Utah International Inc. -- which is investigating the feasibility of several Lurgi plants capable of producing 250,000 Mcf per day, the first tentatively scheduled for startup in 1975 or 1976. No application has been submitted to the FPC for this proposal.

In addition, FMC Corp. recently formed a consortium with Tenneco Inc. and Panhandle Eastern Pipe Line Co. to construct a pilot plant near Princeton, New Jersey in order to test the commercial feasibility of the so-called COGAS process for conversion of char into synthetic pipeline gas, with synthetic crude oil as a by-product. If pilot plant operations are successful, FMC envisions construction of a commercial plant later in the decade to produce 250,000 Mcf per day of high Btu synthetic gas and 24,000 barrels per day of synthetic crude. Cost figures of 75¢ to 90¢/Mcf for gas and $4.00 per barrel for oil have been mentioned by FMC, but these figures must be regarded as speculative at this time.

As noted in Chapter III, efforts to accelerate the commercialization of coal gasification are receiving active federal support. In August 1971 the Interior Department and the American Gas Association entered

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1/ This figure exceeds previous estimates in the general range of 85¢ to $1.0/Mcf for projects of this nature.

into an agreement calling for the joint funding of a research program to test various processes through pilot plant operations, and the most likely of the processes through demonstration plants, over the next eight years. The first four years of the effort -- the pilot plant phase -- will be funded at the rate of $30 million per year, of which two-thirds will be provided by Interior[1/] and the remaining one-third by the gas industry. Two pilot plants are already in operation under this operation, and two more are scheduled for construction in the near future. The second four years, or demonstration plant phase, is estimated to cost about $176 million, but no arrangements for funding have yet been made. Assuming continuation of funding at the necessary levels, it is hoped that one or more commercial processes will be available by 1980.

Several factors will affect the future rate of development of coal gasification. These include the availability of substantial tonnages of coal for conversion, the tremendous capital expenditures required for mining and gasification facilities, environmental consequences of large-scale mining projects (especially those involving strip mining), and problems associated with locating the mine-plant complexes in areas able to provide the necessary reserves of uncommitted coal plus the very large volumes of required process water. Moreover, the economics of coal gasification are highly uncertain at present and must necessarily await the results of further research.

1/ The $20 million annual contribution by Interior (Office of Coal Research) compares with a total expenditure of approximately $28 million by OCR on coal gasification research over the entire period from 1960 through fiscal 1971.

If these obstacles can be overcome, development of an economically viable coal gasification industry offers several benefits relative to certain other supplemental supply alternatives. First of all, no adverse national security impact and no balance of trade problems are presented. Second, coal is, by far, the most abundant of the nation's fossil fuel resources. Third, gasification of coal would permit the use of resources which might otherwise never be directly consumed for environmental reasons.

In short, it is suggested that EPA support the continued federal funding of present coal gasification research efforts. It might also consider participating in proceedings before the FPC on El Paso's currently proposed project and on any others which may be filed in the future. In this regard, one contribution of EPA could be a thorough evaluation of environmental factors in an effort to assure maximum protection while countering unreasonable attacks.

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CHAPTER VI - THE COST EFFECTIVENESS AND TIME REQUIREMENTS FOR ALTERNATIVE REGULATORY STRATEGIES REGARDING GAS SUPPLIES

A number of alternative regulatory strategies are set out in Chapter V with respect to regulatory policies which will affect the supplies of gas in the future. These alternative strategies focused primarily on regulatory policies which could affect domestic production of natural gas.[1/] It is for this reason that the directional cost effectiveness analysis set out in this chapter focuses on domestic supplies of natural gas.

1/ A definitive cost-effectiveness analysis of alternative strategies for increasing supplies of gas for U.S. markets, is beyond the scope of this contract. If such an analysis were undertaken, it should include supplemental supplies (LNG, reformer gas, Arctic gas and coal gas) as well as domestic production, including, among other matters, the following interrelated considerations: the anticipated "city gate" cost of alternative levels of supplies, supplemental as well as domestic, over a sufficient span of time to move beyond the "first generation," especially with regard to coal gas; the comparison of these city gate costs with alternative types of energy (oil, coal, nuclear, etc.) for specific market sectors (residential, commercial, industrial, electric power) in specified regions of the country, taking also into account the resulting benefit to society by reducing air pollutants; the time span for realizing substantial base load volumes, contracting, for example, the two to three year lead time for a reformer gas plant versus the need for further five to ten years) pilot plant research for coal gasification; the impact on national macro-economic considerations, such as balance of payments, security of supply, the intent to reduce further exportation of refining capacity, i.e., the MOIP.

All of the more important alternative strategies pertain to regulation by the Federal Power Commission:[1/]

(1) Amend the Natural Gas Act to deregulate field prices of gas produced in the United States;

(2) Amend the Natural Gas Act to deregulate field prices of gas produced in the United States and sold under new contracts;

(3) Amend the Natural Gas Act to instruct the FPC in its continuing regulation of field prices of gas to grant "contract sanctity" and to determine reasonable new gas prices by reference to economic factors in the marketplace, not by reference to cost of service; and

(4) Amend the Natural Gas Act by giving the FPC authority to allocate gas supplies among intrastate as well as interstate consumers.

These four alternatives require amending the Natural Gas Act by Congress. The first three affect the field price of domestically produced gas whereas the fourth is adressed to allocating shrinking supplies of gas. Therefore, an optimal strategy for EPA to increase gas supplies in the United States could be to support any of the first three indicated amendments to the Natural Gas Act so as to allow prices of gas under new contracts to rise to their commodity value level in accordance with the mandate of the marketplace. The marketplace will, in time,

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1/ Chapter V also stresses the need for accelerated and regularized leasing of federal OCS lands by the Interior Department. The rate of development of gas reserves underlying OCS lands will be influenced by several factors -- including bonus payments, royalty payments and FPC-allowed prices, among others.

adjust the price to rise to its competitive level vis-a-vis substitutable fuel. To the extent this price elicits, in due course, greater gas supplies produced in the Lower 48 States, the nation's economy will benefit compared with the cost, as demonstrated below.

From the point of view of increasing supplies of gas, the focus is clearly on the field price of domestic gas, and this focus is quite logical. In 1971 production of gas in the Lower 48 States accounted for over 96% of the nation's consumption of this fuel, the balance being imported from Canada. Even under a more pessimistic outlook for future domestic production (as forecast by the National Petroleum Council), gas produced in the Lower 48 States is still projected to account for 75% of U.S. consumption in 1980, Alaska for 5% and the remainder being Canadian overland imports, LNG imports and synthetic gas.

A. The Cost Effectiveness of Increased Field Prices of Gas in the Lower 48 States

Two basic questions must be answered in appraising the cost effectiveness of increased field prices of natural gas in the Lower 48 States:

(1) What is the field price of gas which is equivalent to its commodity value as determined in the marketplace?

(2) If the field price of gas increases to this level, what effect will this have on the supply of gas?

B. The Current Commodity Value of Gas in U.S. Markets

The current commodity value of gas in U.S. markets was the subject of a major study recently completed by Foster Associates for EPA (Contract No. 68-01-05-31) and 23 other industrial and government clients. The title of this study is "The Current and Prospective Commodity Value of Natural Gas in North American Markets, 1972-1982," dated October 1972. The following analysis is based on the findings of this study.

Table VI-1 brings together pricing differentials and market characteristics to provide a basis for estimating the commodity value differential of natural gas on a regional basis for the first quarter of 1972.

The estimates are shown on two separate bases. The first estimate is made by reference to the total gas market and is constructed as follows:

(a) The residential househeating price of gas comparative with the price of distillate and electricity is shown at Column (1) on a weighted average basis.

(b) The firm industrial and commercial price of gas comparative with substitutable fuels is shown at Column (2) on a weighted average basis.

(c) The power plant and interruptible price of gas comparative with substitutable fuels is shown on a weighted average basis.

(d) These three sectors of each regional market are weighted at Column (4) in accordance with the 1971 regional consumption of gas by sector.

THE DIFFERENTIAL BY WHICH NATURAL GAS IS PRICED BELOW ITS COMMODITY VALUE LEVEL IN CONSUMER MARKETS

FIRST QUARTER 1972

(¢/MMBtu)

	Estimated by Reference to the Total Market				Estimated by Reference to the Priority Market		
	Residential a/ (1)	Firm Industrial and Commercial (2)	Power Plant and Interruptible (3)	Weighted Average (4)	Residential b/ (5)	Firm Industrial and Commercial (6)	Weighted Average (7)
A. Interstate Market Regions							
Pacific Southwest	202¢	23¢	10¢	69¢	67¢	23¢	52¢
Pacific Northwest	69	(8)	0	13	44	(8)	13
Northern Plains	94	16	0	32	39	16	28
Great Lakes	93	0	5	35	35	0	16
MidContinent	62	9	7	20	38	9	24
Southeast	93	7	(9)	14	29	7	15
East Appalachian	42	(43)	0	2	5	(43)	(18)
New England	(4)	(79)	(10)	(28)	(36)	(79)	(52)
West Appalachian	121	4	0	52	44	4	22
Subtotal				32¢			14¢
B. Local Market Regions							
Rocky Mountains	183	10	(3)	58	77	10	46
Gulf Coast	124	16	5	20	15	16	16
Total				29¢			15¢

a/ Includes price differential based on electric heating.
b/ Excludes price differential based on electric heating.

Based on this total market approach, the price of gas is found to be below the price of substitutable fuels in 10 of the 11 markets, ranging from a 2¢ differential in the Eastern Appalachian Region to a 69¢ differential in the Pacific Southwest Region. In New England the price of gas is shown to exceed substitutable fuels by a weighted average of 28¢ per MMBtu.

A national average of these regional differentials is achieved by weighting each region in accordance with the gas consumed in these markets. On such a basis, it is found that the price of gas is 32¢/MMBtu below the price of substitutable fuels in the predominantly interstate markets. If the two predominantly local (intrastate) markets are weighted-in, the national average price differential is shown to be 29¢ per MMBtu.

An estimation of the differential by which gas is priced below substitutable fuels in the total national market has the virtue of representing just that -- the composite of the total regional gas markets to the national market. However, the total market estimate embodies several other important considerations.

First, the gas price differential for residential heating is based on a comparison with both distillate and electricity. The gas-electric price differential is very substantial and significantly affects the composite price differential for the total market. No basis exists at this time for adjusting the apparent non-price premium given to electric househeating over gas househeating in several regions of the country.

Second, the total market approach gives full weight to the power plant and interruptible boiler fuel market, although this is not a priority market under current FPC regulation and is expected to decline in importance in the future, based on evolving patterns for allocating limited gas supplies.

Finally, no price-equivalent consideration is given to the non-price premiums attached to gas over oil and coal in the firm industrial and commercial market as well as the power plant and interruptible market.

To eliminate several of these more extreme considerations, an alternative estimate of the differential by which gas is priced below substitutable fuels was prepared on Table VI-1. Made by reference to the priority market (residential, commercial and firm industrial), the estimate is constructed as follows:

(a) The residential househeating price of gas is compared only with the price of distillate, as shown at Column (5) of Table VI-1. The price comparison with electricity is eliminated.

(b) The price of gas in the firm industrial and commercial markets comparative with substitutable fuels is shown on a weighted average basis at Column (6) of Table VI-1.

(c) These two sectors of each regional market are weighted at Column (7) of Table VI-1 in accordance with the 1971 regional consumption of gas by sector.

Based on this priority market approach, the current price of natural gas was found to be below the price of substitutable fuels in 9 of the 11 markets, ranging from a 13¢/MMBtu differential in the Pacific

Northwest market to a 52¢/MMBtu differential in the Pacific Southwest market. Only in the East Appalachian and New England markets is the current price of gas shown to be greater than the price of substitutable fuels.

A national averaging of these regional differentials was achieved by weighting each region in accordance with the gas consumed in these markets. On such a basis, it is found that the current price of gas is 14¢ per MMBtu below the price of substitutable fuels in the predominantly interstate markets, and 15¢/MMBtu with respect to the total United States.

Several comments regarding the construction of this priority market estimate are called for. First, the gas-electric price differential is eliminated because of the impossibility of quantifying the non-price premium. A similar non-price premium favors gas over fuel oil and coal in the firm industrial and commercial markets. Such a premium is sometimes placed "at about 5¢/Mcf." No adjustment is made in this study to account for this premium. In part, the "cleanliness" (i.e., minimal sulfur and particulate content) of gas is indirectly already reflected, and will increasingly be indirectly reflected, in higher prices required for oil and coal at a lower sulfur content to meet air pollution abatement control regulations.[1/] This and other non-price attributes of gas are relevant factors in the marketplace. In some important degree these premiums explain the demand and estimated future increase in demand for gas in the East

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1/ The cost differential created by sulfur content will be used to establish a social benefit of increasing domestic gas supplies. See below.

Appalachian and New England markets where, on a price only basis, gas is currently priced above levels of substitutable fuels.

In summary, the price of gas in U.S. priority consumer markets is found to be below the most conservative estimate of its commodity value level by 14¢ to 15¢/MMBtu in the first quarter of 1972.

These commodity value differentials are directly attributable to the price of gas at the wellhead on the plausible assumption that the pipelines and distributors, in the composite, were earning a reasonable rate of return as of the first quarter 1972.[1/]

Therefore, the commodity value differential, the amount by which gas is priced below substitutable fuels in consumer markets, may be directly added to the first quarter 1972 field price level to determine the commodity value of gas, as set out by the following table.

THE COMMODITY VALUE OF NATURAL GAS
PRODUCED IN THE LOWER 48 STATES
FIRST QUARTER 1972

(Measured at 14.73 psia and 1032 Btu/cf)

		¢/Mcf
1.	Actual average field price of natural gas[a/]	19.9¢
2.	Commodity value differential for natural gas prices[b/]	14.0-15.0
3.	Commodity value of gas in the field	33.9-34.9¢

a/ Field prices of gas sold in interstate commerce as regulated by the FPC.

b/ Determined by reference to priority consumer markets in cents per MMBtu. Statistically, the commodity value differential in the field should be adjusted to 1032 Btu/cf, or 14.4¢-16.0¢. To provide a more conservative estimate, this calculation was not used.

1/ In this regard it should be noted that pipeline tariffs utilized for the first quarter of 1972 include tariffs reflecting rate increases subject to refund.

Thus, the above table indicates a current commodity value of 34 to 35¢ for all gas in the field. However, it is necessary to carry the analysis one step further to consider the role of price under different vintages of contracts, i.e., new gas contracts versus existing gas contracts. This vintage concept is embedded in FPC area rate regulation and is based on the rationale that it is the price of new gas which provides incentive to producers to explore and drill for increased supplies. In a free market, new contract prices clearly change in response to supply and demand factors. At the same time, however, it must be borne in mind that prices under existing, or so-called "old" contracts generate a major portion of the cash flow available for exploration and drilling of new gas reserves. Because of the importance of this cash flow, it is suggested some portion of the commodity value differential, determined as of the first quarter 1972, be assigned to old gas prices as well as to new gas prices. Such an assignment is shown on two bases on the following table.

ALTERNATIVE STRUCTURES FOR PRICING GAS AT ITS COMMODITY VALUE LEVEL IN THE FIELD, BASED ON THE VINTAGE CONCEPT: FIRST QUARTER 1972

(¢/Mcf at 14.73 psia and 1032 Btu/cf)

	Volumetric Weight a/	Actual	Commodity Value Level b/
New gas	14%	22.6¢	60.0¢
Old gas	86%	19.5	30.1
Total gas	100%	19.9¢	33.9¢

a/ Based on 1971 purchases of gas by interstate gas pipelines.
b/ Most conservative estimate for priority markets.

The 60¢ price for new gas seems the more plausible alternative based on current trends. Gas prices under new contracts signed in the Southwest, free of regulatory area pricing constraints, are predominantly in the 30-40¢ range, but there is evidence that prices in the 50¢ range could begin, volumetrically, to have an impact in 1973.[1/] Furthermore, an increase in old gas prices by approximately 10¢/Mcf would have an important positive impact on exploration and well drilling because of the substantial improvement in the cash flow available to domestic producers.

C. The Increase in Gas Production that Would Result from Commodity Value Pricing

The Bureau of Natural Gas, in its February 1972 publication, set out a forecast of natural gas production and new reserve additions for the Lower 48 States. When modified for 1971 results,[2/] and restrained to a minimum national reserves-to-production ratio of 9.0, domestic production, as shown on the following table, is projected to increase to a peak of 23.7 trillion cubic feet in 1975 and decline thereafter, amounting to 20.2 trillion cubic feet in 1982.

1/ Adjustments to supply and demand factors in the pricing of new gas supplies for intrastate markets have been constrained by the Price Commission.

2/ The forecast was prepared before 1971 statistics became available. The BNG forecast reserve additions at 12.0 trillion cubic feet in 1971 and production at 22.8 trillion cubic feet, compared with actual reserve additions of 9.4 trillion and actual production of 21.9 trillion cubic feet.

NATURAL GAS PRODUCTION BASED ON THE
BUREAU OF NATURAL GAS FORECAST a/

(Trillion Cubic Feet at 14.73 psia and 1032 Btu/cf)

Year	Reserve Additions	Production	Year-End Total Reserves	Reserves-to-Production Ratio
1971	9.4	21.9	247.4	11.3
Projection				
1972	13.0	22.6	237.8	10.5
1973	14.0	22.9	228.9	10.0
1974	15.0	23.2	220.7	9.5
1975	16.0	23.7	213.0	9.0
1976	17.0	23.0	207.0	9.0
1977	17.0	22.4	201.6	9.0
1982	17.0	20.2	181.7	9.0

a/ Based on reserves additions projected by the FPC Bureau of Natural Gas in National Gas Supply and Demand, 1971-1990, February 1972.

In projecting these supplies, the BNG report stated:

"We have concluded that an increase from the present level of reserve additions to the average national finding level of the past ten years (17 Tcf annually) is consistent with other factors such as the undiscovered potential and recent regulatory actions, which have increased the wellhead price of gas in several important supply areas. . . . The Commission did find . . . that there exists a positive relationship between gas contract price levels and exploratory effort and on this basis concluded that the higher rates established would result in increased drilling efforts and the development of new gas supplies." 1/

1/ The National Petroleum Council, apparently utilizing the same general assumptions, arrived at a more pessimistic forecast, with production peaking in 1972 at an estimated 22.4 Tcf and declining thereafter, amounting to 15.7 Tcf by 1982. U.S. Energy Outlook, An Initial Appraisal, 1971-1985, November 1971.

Based on this statement, a supply curve can be simulated by reference to commodity value pricing in comparison with prices based on existing area rates. The fundamental assumption in this projection is that the price elasticity of new gas reserves will be +.45 -- i.e., a 10% increase in price will provide a 4.5% increase in new gas reserves.[1/] Utilizing a new gas price of 60¢/Mcf, the projection is shown on the following table.

A FORECAST OF THE PRODUCTION OF GAS IN THE LOWER 48 STATES BASED ON COMMODITY VALUE PRICING

(Trillion Cubic Feet at 14.73 psia and 1032 Btu/cf)

Year	Reserve Additions	Production	Total Reserves	Reserves-to-Production Ratio
1971	9.4	21.9	247.4	11.3
Projection				
1972	13.0	22.6	237.8	10.5
1973	14.0	22.9	228.9	10.0
1974	16.5	23.4	222.0	9.5
1975	19.2	24.1	217.1	9.0
1976	23.6	24.1	216.6	9.0
1977	25.3	24.2	217.7	9.0
1982	27.0	25.3	228.0	9.0

A number of assumptions were utilized in preparing this projection:

1/ This estimate of the elasticity of supply is based on a study by Professor Paul MacAvoy, as set out in Regulation of the Natural Gas Production Industry, a Resources for the Future publication, November 1971.

(1) The reserves additions projected to 1980 and to 1985 by the FPC Bureau of Natural Gas reflect the incentive structure according to the current area pricing format set for South Louisiana (26¢/Mcf for new gas and 21.375¢/Mcf for old gas in the Federal Domain).

(2) New discoveries in the Lower 48 States, according to the historical pattern, will account for 32% of future reserve additions, and extensions and revisions for 68%.

(3) The price of new gas supplies increase from 26¢ to 60¢/Mcf as of January 1, 1973.

(4) Old gas prices will provide sufficient cash flow to generate the capital funds required to explore and drill for the reserve additions implicit in the supply curve.

(5) The elasticity of supply for new discoveries will be +0.45 with a three-year time lag (1976).

(6) The elasticity of supply for extensions and revisions will also be +0.45, realized in graduated steps commencing in 1974 and in full by 1978.

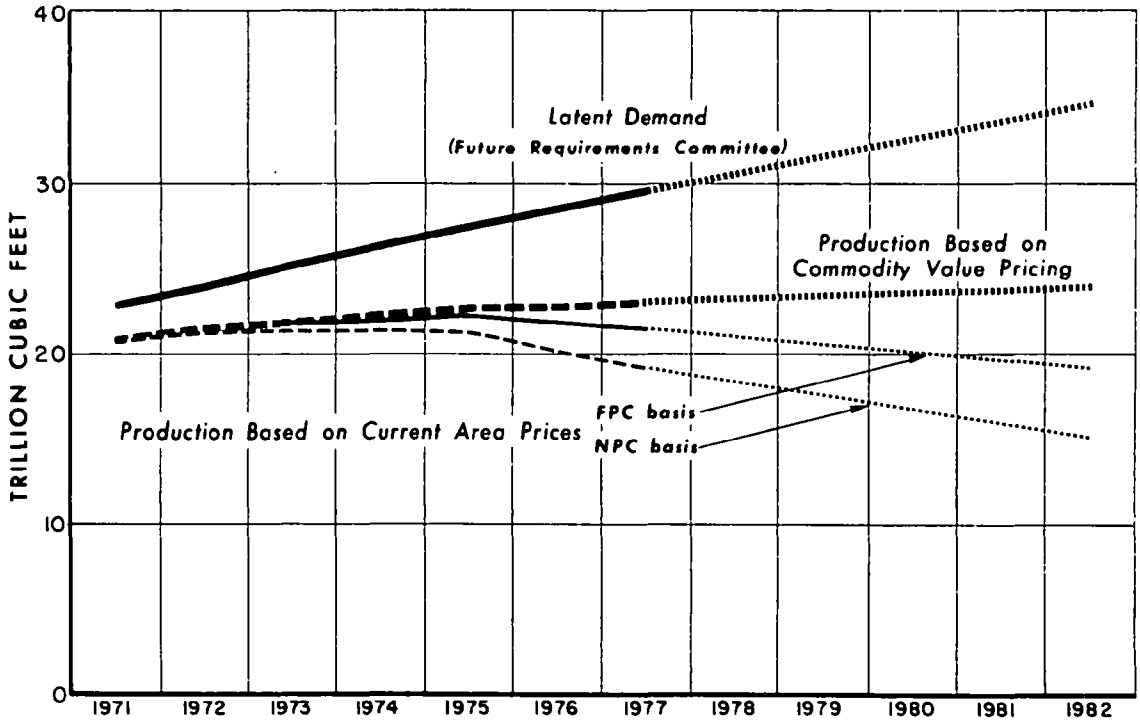
(7) The minimum national reserves-to-production ratio will be 9 to 1.

The results of this projection contrast with the BNG projection in one fundamental way. Whereas the BNG projects production to peak out in 1975 and decline thereafter, the commodity value price projection indicates production will continue to increase at a moderate rate of 0.7% per year after 1975. By 1977, Lower 48 production under commodity value pricing

would be 24.2 Tcf compared with 22.4 Tcf under FPC current price ceilings. By 1982 the comparison is 25.3 Tcf versus 20.2 Tcf.

The impact on pipeline and distributor load balancing problems and marketing patterns will be substantial as between these two projections, compared with the forecast demand. This is shown in graphic form on the following table. Exclusive of field use, and stated at 1000 Btu/cf, production based on commodity value pricing comparative with current area ceiling pricing would make available in 1977 an additional 1.7 trillion cubic feet of gas (4.7 billion cubic feet per day) for deliveries to consumers. By 1982 the difference between the two projections is much greater -- 4.9 trillion cubic feet per year, or 13.4 billion cubic feet per day --

PROJECTED PRODUCTION
COMPARED WITH
LATENT DEMAND IN THE LOWER 48 STATES

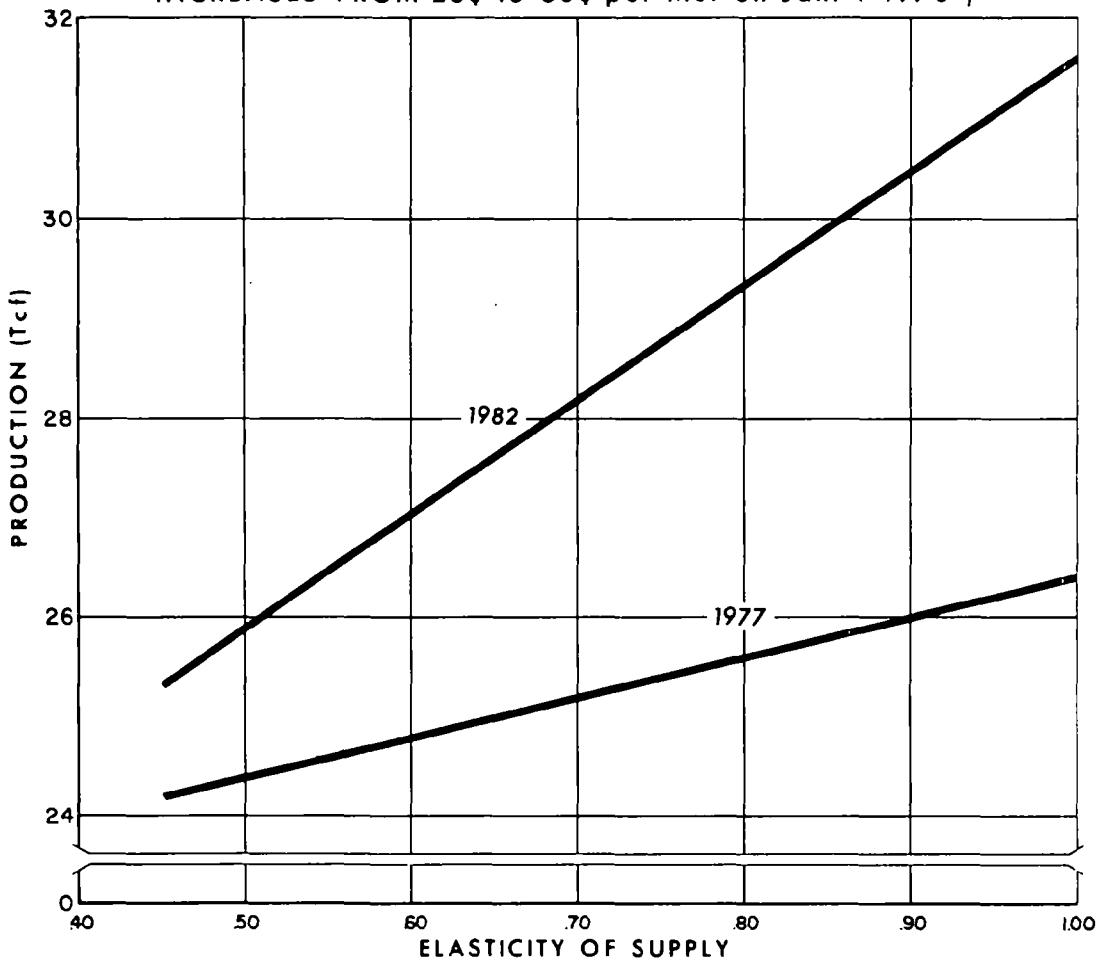


NOTE: Projection is exclusive of field use and is stated at 1000 Btu/cf.

because the BNG production forecast commences to decline after 1975, while the commodity value production forecast continues to increase in a moderate degree.

The above analysis is predicated on an assumed elasticity of supply of +0.45. This could be a conservative assumption for no econometric model can anticipate the numerous and complex variables that will affect the response of industry to a change in field prices. For this reason the following table was prepared to illustrate the impact of a higher elasticity of supply, ranging up to +1.0.

EFFECT OF ELASTICITY OF SUPPLY ON PROJECTED PRODUCTION OF GAS IN THE LOWER 48 STATES
(ASSUMING THE PRICE OF GAS UNDER NEW CONTRACTS INCREASES FROM 26¢ to 60¢ per Mcf on Jan. 1 1973)



Assuming the price of new gas supplies increases from 26¢ to 60¢ as of 1/1/73, the chart demonstrates a high degree of sensitivity by 1982 comparative with 1977. For example, if the elasticity proves, eventually, to be +1.0 rather than +0.45, production by 1977 in the Lower 48 States will be 2.2 Tcf, or 9% higher. By 1982 production will be 6.3 Tcf, or 24.9% higher. The reason for this variance is the inevitable time lags in achieving a higher production after the incentive has been established.

Even so, commodity value pricing cannot be expected to increase production, on any plausible assumption, to meet "latent" demands as shown on the table on page VI-15. Thus, it may be forecast that the "gap" between latent demand and domestic production will be filled in part by supplemental gas supplies and in part by substitutable fuels.

D. The Benefits Compared with the Cost of Incremental Domestic Gas Supplies, 1972-1982

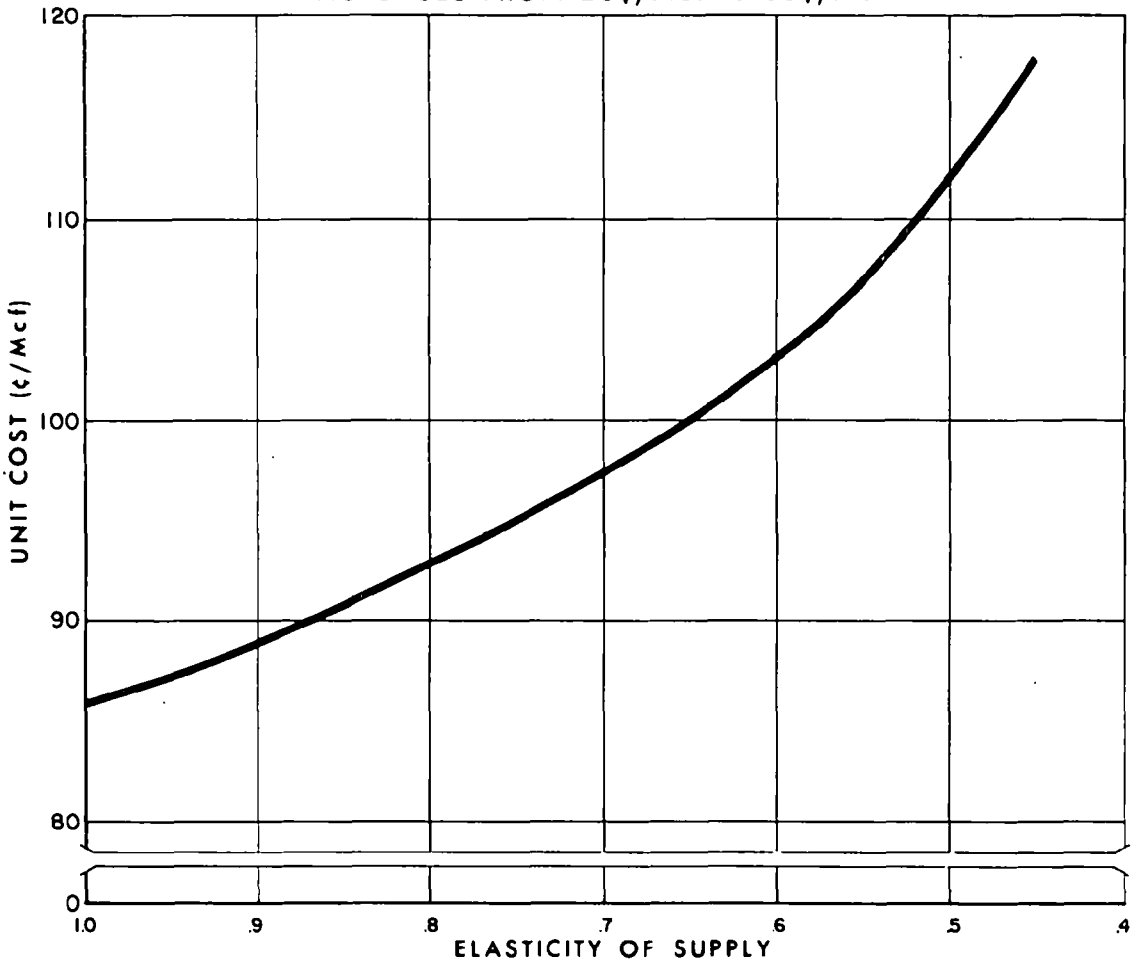
There will be several important benefits to the nation from commodity value pricing of natural gas in the field, including (1) the reconstruction of a positive momentum in the producing end of the industry, which should carry well beyond 1982, and (2) the expectation of a moderately increasing annual production of gas in the Lower 48 States, which should provide a basis for orderly managerial planning by pipelines and distributors with respect to load growth and the assimilation of supplemental gas supplies.

These benefits would not be forthcoming under the incentive structure provided by current area prices, for, according to the BNG and NPC forecasts, the exploration and development momentum would not be regained and production would decline, creating an ever-increasing need to either

forego market growth or, alternatively, inject ever-increasing additional supplies of supplemental gas.

However, the additional supplies of domestic gas resulting from commodity value pricing can only be obtained at a substantial cost comparative with the price of declining supplies as projected under current area pricing policy. This is illustrated by the following figure.

THE UNIT COST OF INCREMENTAL DOMESTIC SUPPLIES
ASSUMING THE PRICE OF GAS UNDER NEW CONTRACTS INCREASES FROM 26¢/Mcf to 60¢/Mcf



For example, the unit cost of these incremental supplies under commodity value pricing is estimated to be 118¢/Mcf, assuming the elasticity of supply is +0.45 and assuming the price of gas under new contracts is 60¢ per Mcf on a commodity value basis versus 26¢/Mcf under existing area rates. If, alternatively, the elasticity of supply proves in fact to be +1.0, the unit cost of the incremental supplies under commodity value pricing would be 86¢/Mcf.

On the assumption of continued FPC regulation of the field prices of interstate gas supplies, there will continue to be a lag in the "rolled-in" field price of natural gas reaching its commodity value level. This lag may be created primarily by the price of old gas falling further behind the price of gas under new contracts which will more readily respond to supply and demand factors.

A projection of the weighted average field prices from the first quarter of 1972 annually to the year 1977 is set out on the following table.

FIELD PRICES OF NATURAL GAS PROJECTED TO 1977 AND 1982

Year	Percent of Total Production		Weighted Average Price Projection		
	Old Gas	New Gas	Old Gas	New Gas[a/]	Total Gas
	------(Percent)-----		------(¢/Mcf at 14.73 psia and 1032 Btu/cf)-----		
1972	100	--	19.9	--	19.9
1973	99	1	22.2	50.0	22.5
1974	97	3	24.5	50.0	25.3
1975	92	8	26.8	56.2	29.2
1976	85	15	29.1	58.0	33.4
1977	77	23	31.3	60.0	37.8
1982	39	61	31.8	60.0	49.0

a/ The average initial price of gas under new contracts is estimated as follows:

1973 and 1974	-	50¢/Mcf
1975	-	60¢/Mcf
1976	-	60¢/Mcf
1977 and 1982	-	60¢/Mcf

"old" gas on this table is defined as the weighted average of "old" and "new" gas according to the current FPC vintage pricing, including all gas contracted through December 31, 1972. "New" gas on this table is defined as gas contracted beginning January 1, 1973.

In 1973 and 1974 the initial price of gas under new contracts is projected to average 50¢/Mcf. From 1975 to 1982 the initial price of gas under new contracts is assumed to average 60¢/Mcf.

Old prices are assumed to increase at an annual average amount of 2.3¢/Mcf per year to 1977, a substantial regulatory lag but reflecting the overriding need for an increased cash flow to explore and drill for new supplies of gas.

It will be noted that the optimal strategy for EPA focuses on new gas contract prices for it is here the "incentive" price is established. However, a basic assumption is made that if the FPC continues to regulate "old" gas prices, it will establish a level sufficient to generate a cash flow required to support exploration and development. If, alternatively, it is assumed the FPC fails to establish "old" gas prices at a sufficient level, then the optimal strategy for EPA must be complete deregulation of field prices.

If field prices are totally deregulated by Congress, the old gas prices are projected to respond more readily to the shift of new gas prices toward their commodity value level, primarily by redetermination-type clauses. By 1977 old gas prices on this basis are projected to be 36.9¢ per Mcf. Furthermore, some 18% of the volume of old gas will be under contracts expiring over this forecast period and therefore renegotiated as

new gas contracts. This would result in the average "rolled-in" price of gas by 1977 being 45¢/Mcf.

As to the benefits, field prices at a commodity value level would spur the development of additional gas supplies by providing greater incentive to drill for gas and increased cash flow to finance exploration and development. The gas pipeline and distribution industry would benefit from increased throughput or utilization of existing capacity. Without allowing gas prices to achieve commodity value levels, natural gas production in the U.S. will decline. The high proportion of total cost represented by fixed costs (costs which do not vary with output) in pipeline and distribution operations results in diseconomies of scale with declining throughput. Cost per unit of throughput increases as utilization of capacity declines.

Natural gas prices fixed by reference to the market would also benefit the energy industry because of the interrelationship of gas with oil, both in terms of exploration effort and corporate structure. The search for gas has become increasingly directional in recent years. Notwithstanding this factor, the price of gas, like the price of oil, makes a contribution to the search for hydrocarbons. To a non-quantifiable degree, higher gas prices will also spur additional drilling for associated-dissolved gas found with oil reserves.

Moreover, the increased cash flow to oil and gas producers resulting from gas will increase the internal funds available for hydrocarbon exploration and development. Hence, commodity value pricing will act to increase supplies of associated-dissolved gas resulting from domestic crude oil production.

It can also be noted that increased exploration and development of gas reserves in the United States will directly increase employment and income in industries servicing the gas production industry. Assuming a 1:1 multiplier for indirect:direct expenditures would result in an estimated total annual contribution of $8 billion to the GNP from 1973 to 1977, and $13 billion annually from 1978 to 1982. Payments to royalty owners (estimated at 13.5% of total production value) would increase from $0.6 billion in 1972 to $1.2 billion in 1977 to $1.7 billion in 1982. Hence, it may be seen that commodity value pricing would have a material impact on GNP in the United States.

Another direct benefit of commodity value pricing for gas would be the contribution to the U.S. balance of payments. Each Mcf of gas discovered due to the greater exploration effort under commodity value pricing would accordingly reduce the need to import oil or gas from other countries.

E. The Benefit of Increased Gas Supplies Resulting from a Reduction of Sulfur Emissions

In summary this chapter has developed alternative strategies which might be pursued by the EPA in seeking to achieve increased gas supplies.

While a number of alternative strategies are available to EPA, the optimal strategy is found to be an incentive structure which would allow the price of new gas contracts to be fixed by reference to the marketplace. This would best be achieved by amending the Natural Gas Act to deregulate field prices of gas produced in the United States and sold under new contracts. The objective could also be attained, with lesser effectiveness

and a greater time lag, by amending the Natural Gas Act to instruct the FPC in its continuing regulation of field prices of gas to grant "contract sanctity" and to determine reasonable new gas prices by reference to economic factors in the marketplace, not by reference to cost of service.

Under either alternative the objective would be to allow new gas prices to reach a "market clearing level," the commodity value level.[1/]

In addition to the benefits to the nation's economy, as described above, the increased supplies of gas which would result from this optimal solution will have a direct benefit with respect to EPA's regulation of sulfur emissions into the atmosphere from stationary sources.

It has been estimated that there will be a short-fall in coal and perhaps oil supplies available to meet sulfur regulations in accordance with State Implementation Plans (SIP). For example, a recent Mitre report to EPA, entitled "Impact of State Implementation Plans on Fossil Fuel Availability and Requirements," estimates that in 1977 approximately 14,760 trillion Btu of low sulfur coal will be required to meet SIP but only 6,960 trillion will be available. Therefore, a deficit of 7,800 trillion Btu of low sulfur coal will exist in that year. The report also estimates that in 1977 approximately 9,030 trillion Btu of low sulfur fuel oil will be required to meet SIP, but only 6,864 trillion will be available. Therefore, the deficit of 2,166 trillion Btu of low sulfur oil will exist. On

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1/ A necessary companion to this optimal solution is the need to price flowing (old) gas at a level sufficient to generate a cash flow which will support the expanded exploration and well drilling activity resulting from increased incentives caused by allowing new gas prices to reach commodity value levels.

this basis there will be a short-fall of low sulfur oil and coal amounting to 9,966 trillion Btu by 1977 in the United States if the SIPs are to be met, in accordance with Congressional mandate.

It is within this context that an increasing supply of domestic gas would be of direct benefit to the Congressional mandate to reduce sulfur emissions into the atmosphere from stationary sources.

The contrast between the projected production of gas in the Lower 48 States under existing FPC area price ceilings, and the optimal solution afforded by commodity value pricing of gas in the field, is summarized on the following table.

FORECAST OF GAS PRODUCTION IN THE LOWER 48 STATES[a/]
(Trillion Cubic Feet at 1000 Btu/cf)

	Based on Current Area Prices b/	Based on Commodity Value Pricing Assuming Elasticity of Supply at +0.45	+0.75	+1.0
1977	21.4	23.1	24.2	25.2
1982	19.3	24.1	27.5	30.1

a/ After exclusion of field use.
b/ Based on the Federal Power Commission estimate set out in National Gas Supply and Demand, 1971-1990, February 1972.

The benefit resulting from commodity value pricing compared with current area pricing would be an increase in supplies of gas produced in the Lower 48 States in 1982 ranging from 4.8 to 10.8 trillion cubic feet, depending on the elasticity of supply that will ultimately prove to be the fact.

This increased production of gas will directly offset the projected deficiencies in low sulfur coal and oil availability, and doubly so, if additional supplies of fuel oil will be required in the future to fulfill shortfalls in gas demand caused by declining gas production projected on the assumption of a continuation of current FPC area price ceilings.

The analysis to this point demonstrates the volumetric benefit of increased gas production from the point of view of reducing sulfur emissions in the United States. An equivalent expression in dollars can be estimated. A literature search found no definitive study of the direct dollar benefits to the nation of reduced sulfur emissions. Accordingly, the sulfur tax proposed by bills submitted in 1972 to Congress will be used to translate increased gas production into dollars of benefit from the point of view of reducing sulfur emissions.

The Pure Air Bill of 1972, the sulfur tax sponsored by the Administration could, in the opinion of EPA, provide a strong economic incentive for the reduction of sulfur in fuels. If passed, this tax would become effective in 1976 and be levied on sulfur emitted into the atmosphere from combustion, refining, smelting and other processes. It would apply in those regions where the primary and secondary standards are not met. For those regions where the primary standards are not met, the amount of the tax would be 15¢ per pound of sulfur emitted. Where the secondary standards are exceeded, the levy would be 10¢ per pound of sulfur emitted.[1/]

1/ For example, residual fuel oil with 1.6% sulfur would be taxed 9¢/MMBtu and 14¢/MMBtu at the 10¢ and 15¢ rates, respectively. For coal containing 3.0% sulfur, the tax would be 24¢/MMBtu and 36¢/MMBtu.

Alternative bills submitted to Congress in 1972 would tax sulfur emissions at a rate of 20¢ per pound regardless of whether ambient air standards are not exceeded.[1/]

If it be assumed the shortfall in low sulfur oil and coal can only be filled by oil and coal at 2.5% sulfur by weight, then the "cost" to society can be determined by reference to the sulfur tax, summarized on the following table.

ESTIMATED UNIT BENEFIT OF AN INCREASED GAS SUPPLY IN THE UNITED STATES WITH RESPECT TO REDUCTION IN SULFUR EMISSIONS

	¢/MMBtu
A. Gas replaces coal containing 2.5% sulfur (by weight)	
1. Sulfur "tax" at 15¢ per pound	28.8
2. Sulfur "tax" at 20¢ per pound	38.4
B. Gas replaces fuel oil containing 2.5% sulfur (by weight)	
1. Sulfur "tax" at 15¢ per pound	20.7
2. Sulfur "tax" at 20¢ per pound	27.5

Because coal contains more sulfur per unit of heat content (Btu content), the benefit to society of gas replacing high sulfur coal ranges from 28.8 to 38.4¢/MMBtu while the benefit of gas replacing high sulfur fuel oil ranges from 20.7¢ to 27.5¢/MMBtu.

When related to volumes shown on the table on page VI-24, the benefit to society from increased gas supplies projected to 1982 in monetary terms is summarized on the following table.

1/ H.R. 10480 and H.R. 53057.

ESTIMATED TOTAL BENEFIT OF AN INCREASED GAS SUPPLY IN THE UNITED STATES WITH RESPECT TO REDUCTION IN SULFUR EMISSIONS

	Increase in 1982 Gas Supply Resulting from Commodity Value Pricing Commencing January 1, 1973 a/	Cost Benefit in 1982 if the Increased Gas Supply Replaces High Sulfur Coal or Oil	
		Coal	Oil
	(Trillion Cubic Feet)	(Million Dollars)	
Maximum	10.8	$3,100-4,147	$2,236-2,970
Minimum	4.8	1,382-1,843	994-1,320

a/ Supply range reflects alternative elasticity of supply assumption ranging from +0.45 to +1.0.

Source: Tables on pages VI-24 and VI-26.

Another way of demonstrating the benefits of increased gas supplies to society is the reduction in emissions of sulfur dioxides that could be attained by replacing high sulfur coal and residual fuel oil. This is set set out in the table below.

ESTIMATED BENEFIT OF AN INCREASED GAS SUPPLY IN THE UNITED STATES WITH RESPECT TO REDUCTION IN SULFUR DIOXIDE EMISSIONS

	Increase in 1982 Gas Supply Resulting from Commodity Value Pricing Commencing January 1, 1973	Reduction in SO_2 Emissions in 1982 if the Increased Gas Supply Replaces:	
		High Sulfur Coal a/	High Sulfur Oil a/
	(Trillion Cubic Feet)	(Million Tons SO_2)	
Maximum	10.8	19.7	14.2
Minimum	4.8	8.8	6.3

a/ Assuming a 2.5% sulfur fuel.

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7. Author(s) M. W. Rockefeller and R. L. Schantz			8. Performing Organization Rept. No. --
9. Performing Organization Name and Address Foster Associates, Inc. 1101 Seventeeth Street, N.W. Washington, D.C. 20036			10. Project/Task/Work Unit No. 11. Contract/Grant No. 68-02-0640
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15. Supplementary Notes

16. Abstracts

A study was conducted to review the current regulatory picture affecting the supply and distribution of natural gas and low sulfur fuel oil, to analyze possible changes in this regulatory picture, and to appraise alternate regulatory strategies which could bring about increased supplies of these clean-burning fuels. The results of the study are contained in two separate reports, one report for natural gas and the other for fuel oil. Also, abridged copies of the two comprehensive reports are provided.

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Law

17b. Identifiers/Open-Ended Terms

Air pollution
Natural gas

17c. COSATI Field/Group 5D

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