ALTERNATIVE REGULATORY POLICIES FOR DEALING WITH THE NATURAL GAS SHORTAGE[1]

by

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The results of this project would not have been possible without the support of our research assistants at M.I.T. We would like to extend our sincere appreciation to Robert Brooks, Krishna Challa, Ira Gershkoff, Marti Subrahmanyam and Philip Sussman for their energetic and enthusiastic help in developing a computerized data base during the summer of 1972, and estimating and simulating the model over the past few months. They worked many long hours, and often under considerable time pressure. We received considerable support from the National Bureau of Economic Research Computer Center in the use of the TROLL system for the estimation and simulation of the model, as well as the maintenance of our data base. We would like to thank Mark Eisner, Fred Ciarmaglia, Richard Hill, and Jonathan Shane for their help in using TROLL. We would also like to express our appreciation to Morris Adelman and Gordon Kaufman of M.I.T., and Robert Fullen and Wade Sewell of the Federal Power Commission for their comments and suggestions. Commissioner Nassikas of the F.P.C., Mr. Charles DiBona of the White House Staff, and staff members of the Senate Commerce Committee were of substantial assistance in formulating policy alternatives. Finally, more than six dozen readers of the Phase I version of the model provided critical comments necessary for reformulating the model along the lines presented below. We are obligated to them all, and absolve them from responsibility for the results by granting them anonymity.

ABSTRACT

Low wellhead ceiling prices over the past decade have led to the beginning of a shortage in natural gas production. If the demand for gas grows as expected during the 1970's, and if ceiling prices remain low as a result of restrictive regulatory policy, this shortage could grow significantly. This paper examines the effects of this and alternative regulatory policies on gas reserves, production supply, production demand, and prices over the remainder of this decade. An econometric model is developed to explain the gas discovery process, reserve accumulation, production out of reserves, pipeline price markup, and wholesale demand for production on a disaggregated basis. By simulating this model under alternative policy assumptions, we find that the gas shortage can be ameliorated (and after four or five years eliminated) through phased deregulation of wellhead sales, or through new regulatory rulings, either of which imply moderate increases in the wellhead price for new contracts. These results are also rather insensitive to alternative forecasts of such exogenous variables as GNP growth, population growth, and changes in the prices of alternate fuels.

1.1 Introduction

A substantial shortage of natural gas has been developing over the last few winter heating seasons. Reports of the Federal Power Commission indicate that in the winters of 1970 to 1972 gas supplies were cut off with increasing frequency, and for longer periods of time, throughout the North and Eastern portions of the United States.[1] This has been a matter not only of cutting off supplies in peak periods to industry -- as occurred in Cleveland in January 1970 when 30,000 employees of 700 companies were laid off for 10 days as a result of gas interruptions -- but of systematic curtailments of deliveries to certain classes of consumers. During 1971-1972, seven major interstate pipelines curtailed service throughout the winter season to existing customers. Service entering the Northeastern part of the country from Texas Eastern Transmission Corporation was curtailed 18 percent, from Transcontinental Gas Pipeline 9 percent, and from Trunkline Gas Company 27 percent. Service throughout the region from New Mexico to Southern California was curtailed by El Paso Natural Gas Company by 15 percent. The Federal Power Commission staff has shown deliveries falling short of the amount of gas demanded for consumption by 3.6% in 1971 and by 5.1% in 1972, and has predicted that production will fall short of demand by 12.1% by 1975.[2]

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[1] Federal Power Commission, Proceedings on Curtailment of Gas Deliveries of Interstate Pipelines (1972).

[2] Federal Power Commission, Bureau of Natural Gas, Natural Gas Supply and Demand 1971-1990 (1972), p. 123.

These estimates encompass recent and expected future production shortages. The amounts do not include anywhere near all of the unsatisfied demands for gas. The "markets" for natural gas are not spot markets for production, but rather center on sales of reserves. The pipeline buyer offers to take new gas deposits out of the ground, and pays for this production, so as to deliver gas to residential, commercial and industrial consumers throughout the United States. The transaction involves the dedication of reserves by oil and gas discovery companies to pipelines, and this is followed by a transaction in which the pipelines make commitments to deliver production to final consumers over a ten to twenty year period. The reserves markets have experienced shortages to a much greater extent than shown by recent production shortages (according to one estimate, new reserves have been more than 50 percent short since 1961[1]). Also, it has been estimated that demands for new production by both old and new potential buyers together exceeded the total supply of new production available by more than 50%.[2] These unsatisfied demands were never registered by curtailment proceedings because most of the new potential buyers did not receive new service from the pipelines. This shortage was realized

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[1]The estimate was obtained from a four-equation supply and demand model of natural gas reserves constructed on the basis of data over the 1950's and fitted to values of the exogenous variables over the 1960's. The difference between the fitted values of reserves --those that would clear the market -- and the actual valuesof reserves made available in fuel producing markets to go to the East Coast and Midwest was more than 50% of fitted reserves each year from 1961 to 1968. Cf. S. Breyer and P. MacAvoy, "The Natural Gas Shortage and the Regulation of Natural Gas Producers," Harvard Law Review, 86: 941-987 (1973), pp. 968-976.

[2]Cf. Breyer and MacAvoy, op. cit., Table 1, p. 975.

in additional demands for other fuels with less satisfactory burning and air polluting characteristics.

Production curtailments have immediate effects on the consumer, requiring him to use stand-by heating facilities or possibly to do without heating entirely. The larger shortage of new production contract commitments has more diverse effects. Some consumers are required to go to other fuels -- with the result that their consumption costs are increased, or that pollution is greater so that social costs are increased. Other consumers can work their way around the shortage by changing locations or by offering various premia to be put at the head of the queue. In general, the economic and locational effects of the shortage are likely to be significant.[1]

The political consequences are another matter. The contract sales of gas at the wellhead and at the city gate are closely regulated by the Federal Power Commission, so that the F.P.C., the Congress, and the Office of the President become focal points for complaints that regulatory policies have either caused or failed to ameliorate the shortages. With neither producers nor consumers supporting the regulatory process -- neither clearly benefiting from the shortage -- the possibility of significant political losses for legislators or regulators is substantial.

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[1]An initial attempt is made in Breyer and MacAvoy to measure the economic effects of the shortage on consumers. It is argued there that the reserve shortage is incurred by residential and commercial consumers buying from regulated interstate pipelines, while industrial consumers buying in unregulated transactions do not experience the shortage to the same extent. Because of the magnitude of the amounts short in the 1962-1968 period, final residential and commercial consumers are believed to have been made worse off as a group from a combination of lower regulated prices and large shortages. Cf. Breyer and MacAvoy, op. cit. No attempt is made here to refine these estimates with the more advanced econometric model discussed below. But additional work along these lines -- leading to an assessment of optimal levels of shortage in terms of economic effects -- will be forthcoming in a later article.

Reactions to the potential adverse political effects have been along two lines. The first has been to call for the loosening of regulation of contractual agreements at the wellhead. President Nixon in April 1973 called for deregulation of wellhead prices on new contracts; the Chairman of the Federal Power Commission at the same time argued that "gas supplies are short ... and the way to encourage more drilling and discoveries may be to let prices rise."[1] Proposals for deregulation are based on the argument that Federal Power Commission price control procedures have restricted price increases, while cost increases have reduced supplies and while there have been large demand increases. Thus, decontrol would result in higher prices in order to clear the market of excess demand; but the higher prices would be an inducement to take on the exploration and development of higher cost reserves -- so as to add to reserve supply -- and also an inducement for those with the lowest alternative costs to move over to alternative fuels -- so as to reduce total demands for new reserves.

The second reaction has been to the opposite effect. Proposals have been made to put in stronger controls over wellhead contracts. Draft bills proposed by staff of the Senate Interior and Commerce Committees extend Federal Power Commission jurisdiction to cover not only interstate sales to pipelines, but all intrastate sales now outside the jurisdiction of the Federal Power Commission. The requirement that the Federal Power Commission set "just and reasonable rates" on the basis of historical average costs of exploration and development is reaffirmed. Proposals are made to

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[1]Cf. "F.P.C. Head Urges End to Gas Curbs," The New York Times, April 11, 1973, p. 19.

further the development of artificial gas or liquefied natural gas to replace the short supplies of inground natural gas reserves within the domestic United States. In effect, prices are held constant and price controls are extended to encompass all relevant sources of supply and demand under this policy.

The rationale for strengthened regulation is that, "given the relatively large unsatisfied demand for gas, deregulation of natural gas prices would lead to massive increases in wellhead prices to abnormally high levels."[1] There would be little increase in supply -- "there is evidence that gas supplies are relatively inelastic in the short run." There is also asserted to be some basis for arguing that present regulation is not the cause for the present shortage. At least, "although cost based regulation was slow in getting started, it is an adequate method of regulation that has been developed in the 1960's. Many of the uncertainties have been worked out.... The system of regulation can meet the needs of the 1970's to elicit the necessary supply of natural gas at the lowest reasonable price."[2]

These proposals will be evaluated in this paper. After a more explicit rendition of alternative policies, the industry into which these policies are to be introduced is discussed in some detail. Then an econometric model for policy analysis is described and, finally, the model is used to evaluate the policy options. The evaluation is in terms of the extent to

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[1]Staff Memorandum to the Chief Counsel, Senate Commerce Committee on "Proposed Amendments to the Natural Gas Act," (dated April 24, 1973), p. 4.

[2]Senate Commerce Committee Staff Memorandum, op. cit., p. 5.

which the options ameliorate the shortage -- and at what "cost" in terms of higher field or wholesale prices of natural gas.

1.2 Three Policy Alternatives

Frequent changes in the size of the gas shortage, and in policies towards other fuels, bring forth even more frequent changes from Congress and the Office of the President in proposals for dealing with the gas shortage. Each of these new policies could be catalogued and evaluated -- but the results would be so specific as to be relevant only to that policy and the duration of the policy might well be rather short. Alternatively, the policies can be characterized along two or three dimensions; this is attempted here, in the expectation that the characterizations will approximate the many specific alternatives to be considered, accepted or rejected by the Government in the coming three or four years.

The first alternative policy is that of deregulation of wellhead prices of natural gas. The Federal Power Commission sets regional limits on prices for gas dedicated to interstate pipelines; these limits would be loosened or eliminated in a number of specific policy proposals. In general, the Federal Power Commission price ceilings would be eliminated only after a number of years, by taking controls off prices in all new contracts signed in each year (the time lag in price increases would be extensive, since most of the flowing gas is under old contracts signed in previous years). Even these prices would not be free to rise to a level that would clear

out all the excess demands immediately, since most proposals -- including President Nixon's Energy Message of April 1973 -- decree that there would be some national ceiling imposed on new prices in keeping with gradual elimination of the deficit and with anti-inflationary price controls. The gradual loosening of price controls is coupled with "short term" rationing schemes that may involve the extension of regulatory jurisdiction to presently unregulated companies that are bidding up prices. This "class of policies" can be evaluated in terms of (a) elimination of price controls under new contracts, (b) an overall price ceiling in keeping with a 50% increase in average field price over five years, (c) some regulatory jurisdiction over all field sales by the Federal Power Commission.

The alternative contrasting class of proposals centers on more rather than less regulation by the Federal Power Commission. Prices would be set regionally or nationally on the basis of "cost of service." The cost of service is found by Commission and Court judgment of historical records on average exploration and development costs in the region. All production in the region would come under the jurisdiction of the Commission (except perhaps for the smallest producers who would be exempt to cut down on the number of case reviews). Production under these conditions would admittedly be short of demands: holding prices to historical averages essentially limits reserves or production to amounts equal to or less than historical levels, and these historical levels were not sufficient to meet demands in the past. As a result, attention has to be centered on inducements under regulation for the development of alternative gas supplies, either through manufacture or import in liquefied form. These alternative supplies would

be regulated as well. As a result, the second "class of policies" would (a) set price ceilings close to 1972-1973 price levels, with perhaps a one cent per annum increase as historical average costs rise slowly with inflation, (b) all dedications of reserves and production of gas are under the jurisdiction of the Federal Power Commission, and (c) manufactured or liquefied gas is priced under regulation according to the specific cost of providing these products.

These alternatives are basically contradictory, and it does not seem likely that amendments could be made to one or the other so as to capture the loyalty of those supporting the alternative. If neither can be made politically effective, then the relevant alternative is the status quo which consists of regulation according to public utility principles at the Federal Power Commission. The Commission has followed policies in recent years of allowing field price increases in keeping with "changes in historical costs" where these "changes" have been defined to be as large as conceivable. Area ceilings reached by negotiated settlements between producers and consumers have been proposed to the Commission and the Commission has found them to be "reasonable ceiling prices" not outside the range of possible average costs.[1] Comparisons with costs could be made in the near future that would justify higher future prices, if the Commission so willed -- comparisons of cost on the most recent contracts for sale of intrastate (unregulated) gas, rather than of interstate (regulated) gas sold over the last few years. The Commission, in the 1971-1973 period, allowed prices on new contracts to increase on average by five cents per thousand cubic feet,

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[1]Cf. Southern Louisiana Area Rate Proceeding, 46 FPC 86 (1971). Cf. also Hugeton-Anadarko Area Rate Proceeding, 44 FPC 761 (1970).

after having held prices constant over the 1960's; the regulator can continue to find estimates of historical average costs that would allow further price increases so as to alleviate shortages. But there are limits to the extent of price increases in keeping with some estimate of costs. Thus, the third "class of policies" that can be characterized as maintaining the status quo includes (a) prices that increase from two to four cents per Mcf in each of the next five years, including one cent per annum price increases in keeping with general cost increases, (b) limited regulatory jurisdiction over intrastate sales, and (c) manufactured or liquefied gas would have regulated price ceilings in keeping with their respective costs of service.

2. Characteristics of an Economic Model of Natural Gas Reserves and Production

Our goal in building and simulating an economic model of natural gas markets with explicit policy controls is to predict and analyze the effects of alternative regulatory policies. The model is to provide a vehicle for performing simulations into the future using different policy options, so as to indicate the effects of the options on the levels of prices and the size of the shortages. Thus, its formulation stresses prices, reserve quantities, production quantities, and associated demands for production.

The model, which will be described in more detail in the next section, treats simultaneously the field market for reserves (gas producers dedicating new reserves to pipeline companies at the wellhead price) and the wholesale market for production (pipeline companies selling gas to public utilities and industrial consumers). The linking of these two markets is

an important characteristic of the natural gas industry. Delivery in the wholesale market is a determinant of pipelines' demands for gas reserves in the field market, and the price on new reserve contracts in the field market is a determinant of pipeline delivery costs and thus wholesale delivered prices.

2.1 Field Markets

These markets are the locus of transactions between oil and gas producers having volumes of newly discovered reserves and pipeline buyers seeking to obtain by contract the right to take production from these reserves. The determinants of the amount of reserves committed by the oil and gas companies include first the geophysical characteristics of inground deposits of oil and gas. Additions to reserves come about from additions in (1) gas associated with newly discovered or developed oil reserves, and (2) "dry" gas volumes found in reservoirs not containing oil; both result from (a) new discoveries, and (b) extensions of previous discoveries, or (c) revisions of earlier estimates of previous discoveries. The amounts actually in place in the producing reservoirs limit the amounts of both associated and non-associated new gas reserves that can be "supplied" or dedicated to the pipelines.

There are important economic determinants of the amount of reserves available for commitment, and these include prices of new contracts signed by producers, expected future prices under possibly forthcoming new contracts

in subsequent years, and changes in average and marginal costs of exploration and development. These factors are widely believed to have substantial effects upon reserve availability, although with considerable lag time. Commitments today to higher prices for new contract volumes might lead to immediate increased planning activities for further exploratory or developmental work; this might lead in a year or two to additional drilling activity and, with a subsequent year or two, to the offering of additional reserves for sale to pipeline buyers.

Needless to say, there is a finite amount of gas under the ground that can be discovered, and thus we might begin to observe a depletion effect over the coming years. It is not our objective to predict how much gas there actually is remaining to be discovered, or when this finite resource will be depleted. Any economic model of the gas industry should at least take this depletion effect into account; we will do this by extrapolating the decreasing returns that occurred over the past decade.

The demands for new reserves in the field market are manifest in the willingness to buy of pipeline companies and local (direct) consumers. They seek to obtain long term contracts for the extraction of these reserves. Demand determinants in the field markets include the wellhead price that pipelines and others are willing to

pay for additions to their reserve holdings, the amount of reserves available at a specific location, the location of these reserves, and the final demands for new production by the buyers repurchasing the gas from the pipelines. These demands would be "registered" in the market only so long as there is not regulatory price control which sets regional field prices below those at which total demands are equal to the supplies available of new reserves. After 1961, when ceiling prices were put into effect, the demand variable becomes the exogenous F.P.C.-determined price, since it was lower than the price that would have equilibrated markets.

Production of gas into the pipelines is limited by the amount of reserves available but, within limits, is determined by the needs of the pipeline for final consumer delivery. Production cannot take place at rates greater than 20 percent of installed reserves per annum because of the impermeability of sandstone contained in the reservoirs and because faster rates may reduce the economic value of the remaining reserves. Thus, for both technical and economic reasons, the supply of production out of reserves will be less the lower is the volume of reserves and the lower is the price in t contract commitment. But within these limits, the amount actually taken on a day by day basis can be determined by pipeline buyers seeking to meet their ultimate contract commitments to provide on draft for home consumption.

These characteristics of field markets are found in many "futures" markets in which raw materials are dedicated for production and refining. The differences between this and other markets are that (1) more will be made available for sale if the buyers offer higher prices (in rough approximation to the competitive "supply" mechanism), (2) the lag adjustment process

bringing forth additional supplies of reserves is likely to be long and possibly quite complex, (3) demands depend on prices, but are also derived from final residential, industrial and commercial consumption, and (4) production out of reserves is determined by a combination of technical and economic circumstances, but is likely to be greater the larger the volume of reserves available and the higher the contract prices pipelines are paying for the gas they are taking.

2.2 Wholesale Markets

Pipelines provide gas deliveries, usually under long term contract, to industrial consumers taking gas right off the line and to retail public utility companies for resale to industrial, residential and commercial consumers. The amounts of gas demanded by direct (mainline) industrial consumers and retail gas utilities is believed to depend upon the prices for wholesale gas contracts, the prices for alternative fuels consumed by final buyers, and economy-wide variables that determine the overall size of energy markets. If the consumers are industrial companies seeking gas as boiler fuel or process material, the "market size" variables relate to the demands for these companies' outputs and to their investment in capacity to burn fuel or utilize energy. If the final consumers are households and commercial building owners, then the "market size" variables relate to total population and income.

Wholesale markets also operate with lags. Changes in wholesale prices quoted by pipeline sellers of gas production feed through as changes in final consumer prices and then feed back as changes in final consumer demand quantities; the feedback may take some time because of consumers'

commitment to gas burning equipment and the necessity for that equipment to wear out before demands are reduced. As a result, the effects of price changes may be fekt only in reduced demands for more gas in subsequent years.

The amount of production provided to industrial and public utility buyers is not determined by a fixed "supply schedule" of quantities at various prices. The pipelines offer a specific amount of additional production at a markup over the field purchase price for the reserves backing up that production. The price markups are determined by the cost of transmission and add-on profits limited by Federal Power Commission regulation (following orthodox public utility procedures of finding cost of capital by taking a "fair return" on "fair value" of original investment outlay for pipeline equipment). This procedure is used because the wholesale market is not competitive -- there are one to four sources of transmission capacity in any wholesale buying region -- so that there is no explicit supply function at the wholesale level.

Markup pricing has been formulated to build in significant lags from changes in field contracts. The Commission has followed the policy of allowing wholesale prices to include the markup for historical average costs plus profit for the pipelines and historical average field price for gas at the wellhead. This "rolled-in" price at wholesale is thus changed by an increased field price only to the extent that the new price changes the historical average of all field prices.[1] The full impact of a 10 percent

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[1]The effects of rolling in a "one-shot" price increase on new contracts in 1973 can be spelled out in detail. In 1973, the wholesale price is just the wellhead ceiling price P_c plus the pipelines' markup MC_t. In 1974,
[continued on page 15]

field price change on wholesale prices would occur only after that change had been in effect for roughly five years (assuming 20 percent of contracts in each year are new contracts).

There is considerable simultaneity in the behavior of production, reserves and prices in field and wholesale markets. Field prices determine the availability of new reserves and the production conditions under new contracts simultaneously. Changes in field prices are reflected, albeit slowly, in changing wholesale prices and demands for quantities of production at wholesale. This two-level industry can thus be modeled by simultaneous equations estimates of production and prices as they depend upon reserves and conditions in the final markets for energy.

2.3 The Behavior of Gas Markets When There are Shortages

The behavior of this "mixed" set of markets -- some of which exhibit competitive characteristics of supply while others follow oligopolistic market patterns -- may be rather complex when there are significant excess demands for production. Structural equations, defined to delineate behavioral

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after the ceiling price on new contracts has been raised to P_c', the wholesale price to buyers of new contracts would not be P_c+MC_t, but would instead be given by:

$$PW_{1974} = P_c + MC_t + \frac{\delta Q_{1974}}{Q_{1974}}(P_c' - P_c)$$

where $\delta Q/Q$ is the proportion of "new" production to total production. In 1975, the wholesale price would be given by:

$$PW_{1975} = P_c + MC_t + \frac{\delta Q_{1975}}{Q_{1975}-\delta Q_{1974}}(P_c' - P_c) \ ,$$

and in 1976, it would be given by:

$$PW_{1976} = P_c + MC_t + \frac{\delta Q_{1976}}{Q_{1976}-\delta Q_{1975}-\delta Q_{1974}}(P_c' - P_c) \ .$$

The wholesale price would continue to rise until $\delta Q/(Q-\Sigma\delta Q)$ reached a value of 1; at that point, prices would be fully "rolled in."

patterns, are discussed in some detail later, but for now let us examine how shortages resulting from regulatory policy move through the different layers of transactions for gas reserves and production.

In the field market for natural gas, proved reserves are incremented through the discovery process and depleted through production. The amount of additions to reserves is positively related to some extent to the field price of gas contracts being signed at the locations close to where that volume of new reserves is available. The demands for new reserves by pipelines could be specified in terms of field prices, but under conditions of shortage, the regulated ceiling price P_c prevails rather than the market demand price P*. This is illustrated in Figure 1. Under conditions of shortage, the quantity data fall on the supply but not on the demand function, with the result that the demand function is not observable. At the same time, production out of reserves is affected by the reserve shortage. The supply curve for gas production consists of a marginal development cost curve which represents the cost of incrementing gas production (by running existing gas development wells at higher capacity or by drilling new development wells). The demands for gas production consist of the schedule of wholesale consumption draughts on the pipeline systems at prices equal to field prices plus the pipeline markups necessary to get the gas from the wellhead to wholesale buyers. These final demands may still be met at the beginning of the reserve shortage, as a result of the pipelines calling on existing reserves to produce at a higher rate.

Sufficient production under a condition of reserve depletion cannot be had indefinitely. Eventually, the amount of reserves available to back

production is reduced, and supply of production at ceiling prices is reduced. As the reserve backing becomes smaller, marginal development costs will increase, so that in the presence of fixed ceiling prices, production will tend to fall and a gap is opened between the demands for production and the supplies that will be made available.

The marginal cost curves, the price markup, and a wholesale demand curve for new contracts, are all shown in Figure 2. In this diagram, the ceiling price is sufficient to bring forth production Q* which clears the market at wholesale price P*, which is just the field price plus the pipeline's markup. Under these conditions, the demand curve for production is "registered in the market" or observable as a total quantity demanded with specific price level. However, if the regulated field price is reduced to a level P'_c, excess demand will result equal to (Q_1-Q_0). The supply of production is reduced by price disincentives to a level below the demands put on the pipeline system by retail gas utility companies serving final residential, industrial and commercial consumers. There are shortages both in field reserve and final production markets.

How would an increase in the ceiling price feed through these markets so as to reduce the production shortage? Consider, for example, an increase in wellhead ceiling prices under Federal Power Commission regulation. When the ceiling price is increased, the production cost curve remains fixed initially, since reserve levels would not change immediately and therefore marginal production costs would not change. The higher price, however, would eventually elicit more production out of given reserves Q'_0 and also reduce demands for production from Q_1 to Q'_1 (as shown in Figure 3). Thus,

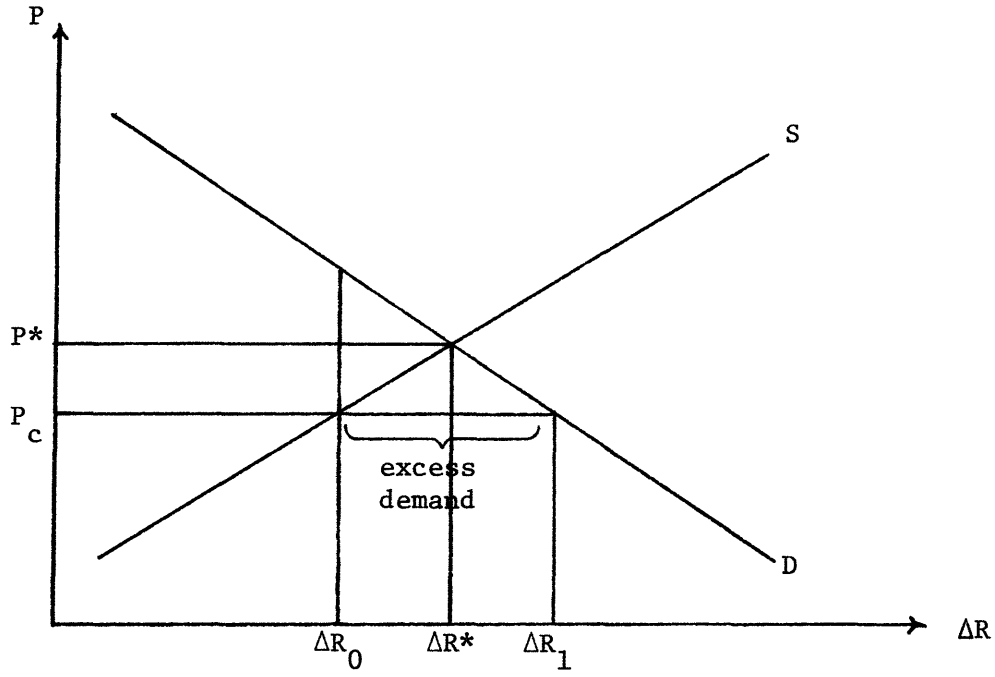

Figure 1: Supply and Demand for Additional Reserves

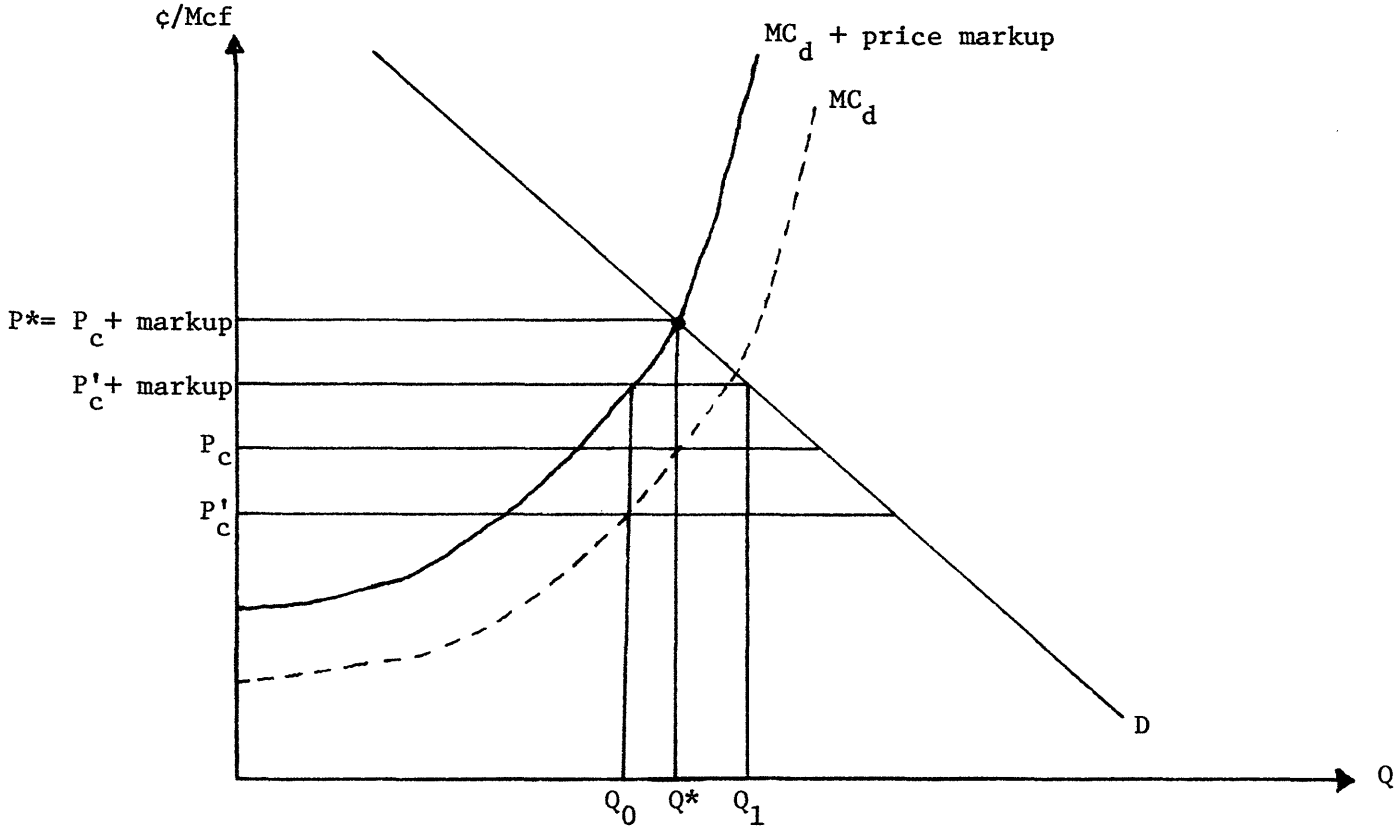

Figure 2: Supply and Demand for Production

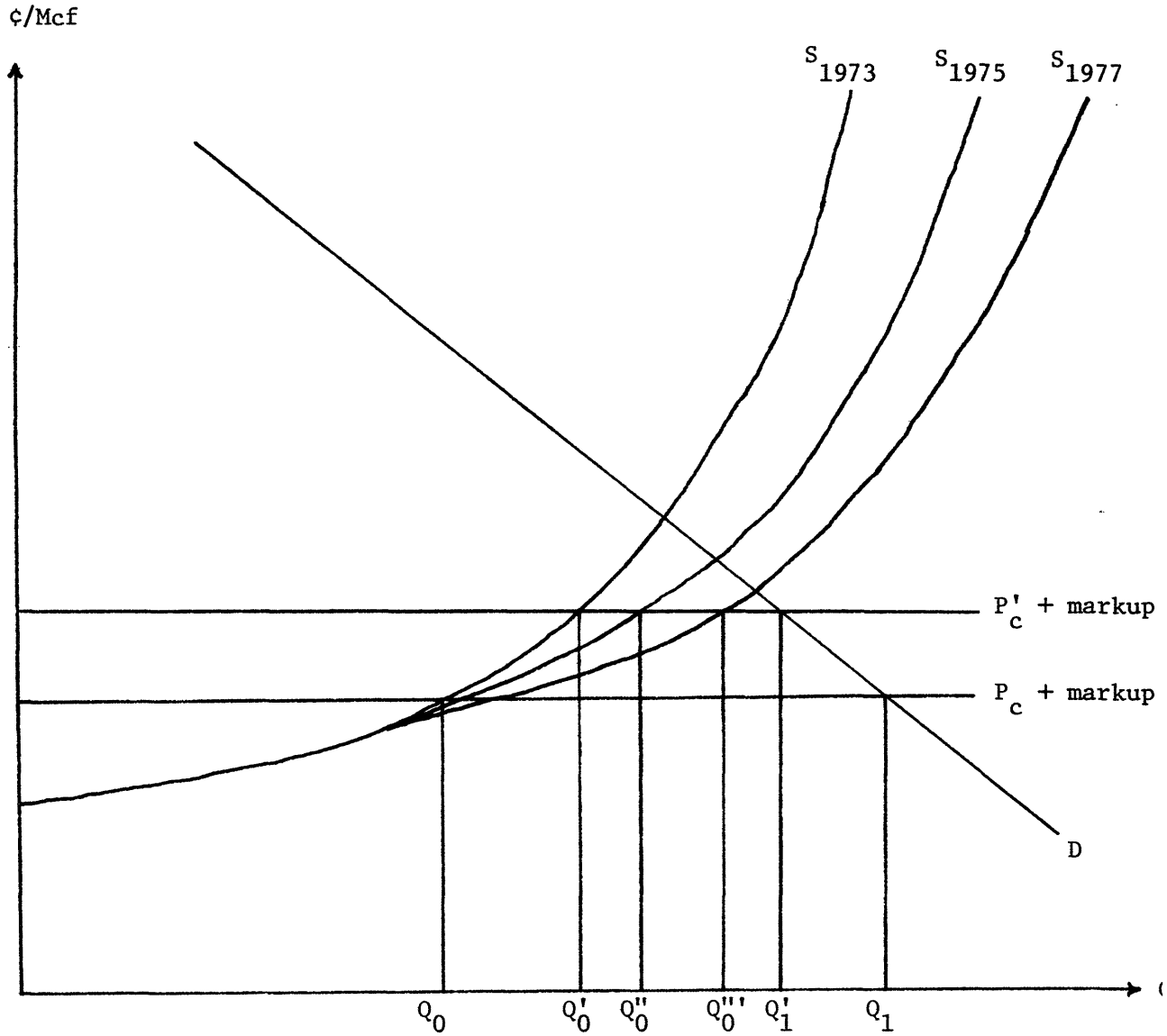

Figure 3

even within the short run, excess demand would be decreased by a price change from (Q_1-Q_0) to $(Q_1'-Q_0')$ even though the change may not be substantial because the "roll-in" pricing practices of the Commission would dampen the demand effect.

After two or three years, however, it is likely that reserve levels will have been increased as a result of the higher level of new contract prices. Higher ceiling prices would stimulate more exploratory drilling which, in turn, should result in new discoveries of gas that add to reserve levels. At that point in time, a given level of production could be induced at lower marginal development costs because of the presence of higher reserve levels. The supply of production curve would have shifted to the right. Even if demand were to remain at Q_1', an increase in supply to Q_0'' would reduce the extent of the shortage. After a few more years, the full effects of the ceiling price increase would have occurred, with the supply of production shifting further to the right so that excess demand had fallen to the even lower level of $(Q_1'-Q_0''')$.[1]

Of course, if we could increase the ceiling price just the right amount, accounting for resulting future shifts in the supply curve and independent shifts in the demand curve (resulting from increased population, national income, etc. as shown by D_{1977}), we might reach a situation where there was no excess demand in 1977. This is shown in Figure 4. Note, however, that <u>until</u> 1977, there will still be some amount of excess demand -- in the first

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[1]This analysis assumes that the pipeline markup is constant with respect to the level of production and that the difference between (P_c + price markup) and (P_c' + price markup) is equivalent to the "roll-in" price increase allowed under regulation. The econometric model discussed later deals with these matters of detail in specific price markup equations.

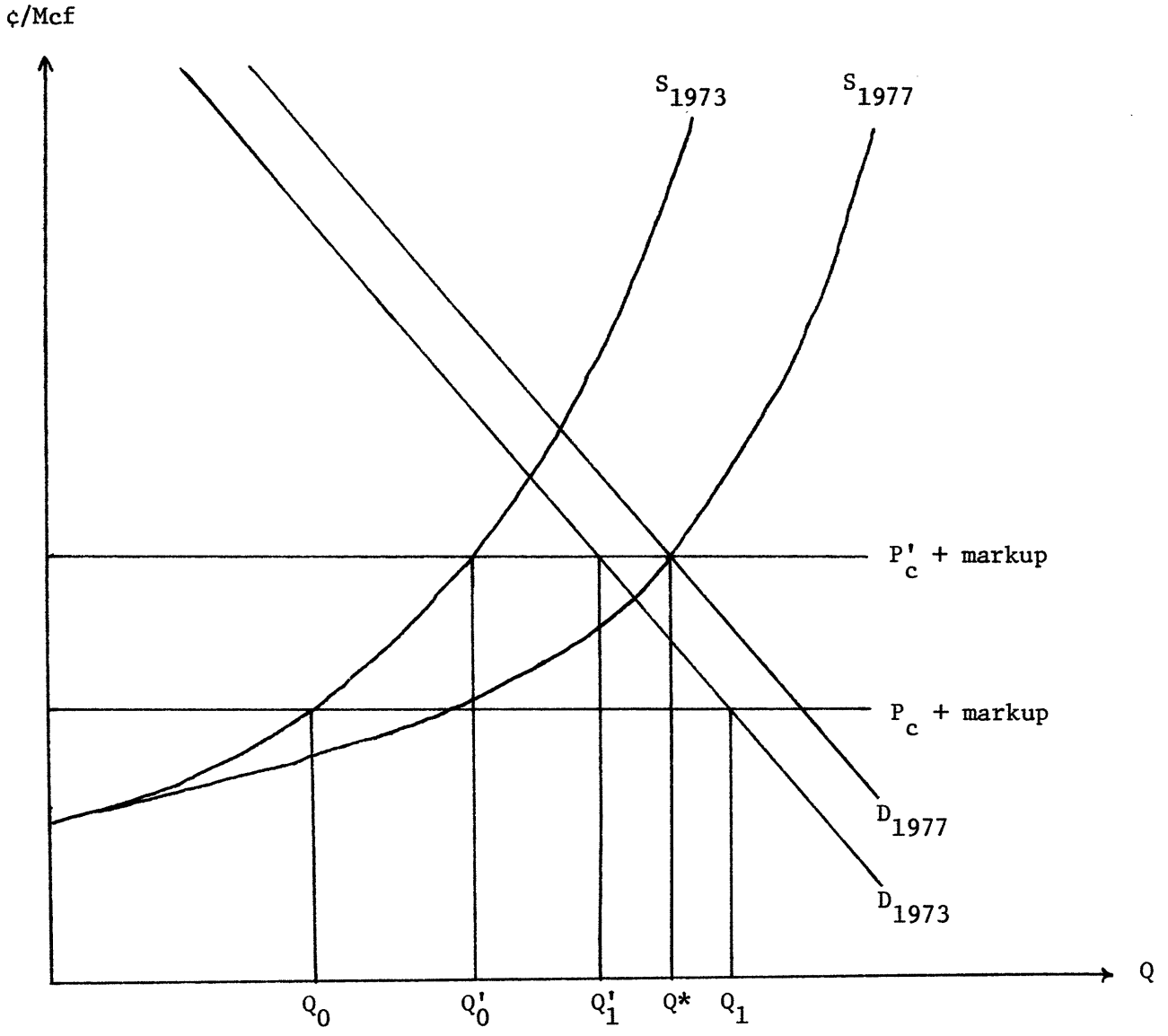

Figure 4

year after the price increase, for example, excess demand will be $(Q_1'-Q_0')$; not until 1977, when the supply curve, demand curve, and price line all intersect at the same point, would there be a level of production, Q*, that results in no excess demand.

What if the field price of all gas were immediately and completely deregulated? This would result in a wholesale price increase to the level P_f^* which, when the regulated markup is added on, would clear the production market immediately (as shown in Figure 5; the supplies and demands for production are both equal in one year to Q*). This substantial price increase would not be the end of the story, however. After three or four years, the supply curve will have shifted to the right, again because increased exploration and discoveries in response to the price increase would have added substantially to the reserve base. The demand curve would perhaps also have shifted to the right after three or four years, but the net result would probably be a decrease in price and further increase in quantity of production over the four year period. This is illustrated in Figure 5 where the 1973 equilibrium quantity Q* is increased over time to Q** as the equilibrium field price P_f^* falls to P_f^{**}.

These examples indicate that pricing policies have a three or four step effect upon the size of the shortage, and it may take several years before the full effects of a price change become apparent. The econometric model presented in the next section allows us to analyze the dynamic impact of alternative price ceiling changes quantitatively.

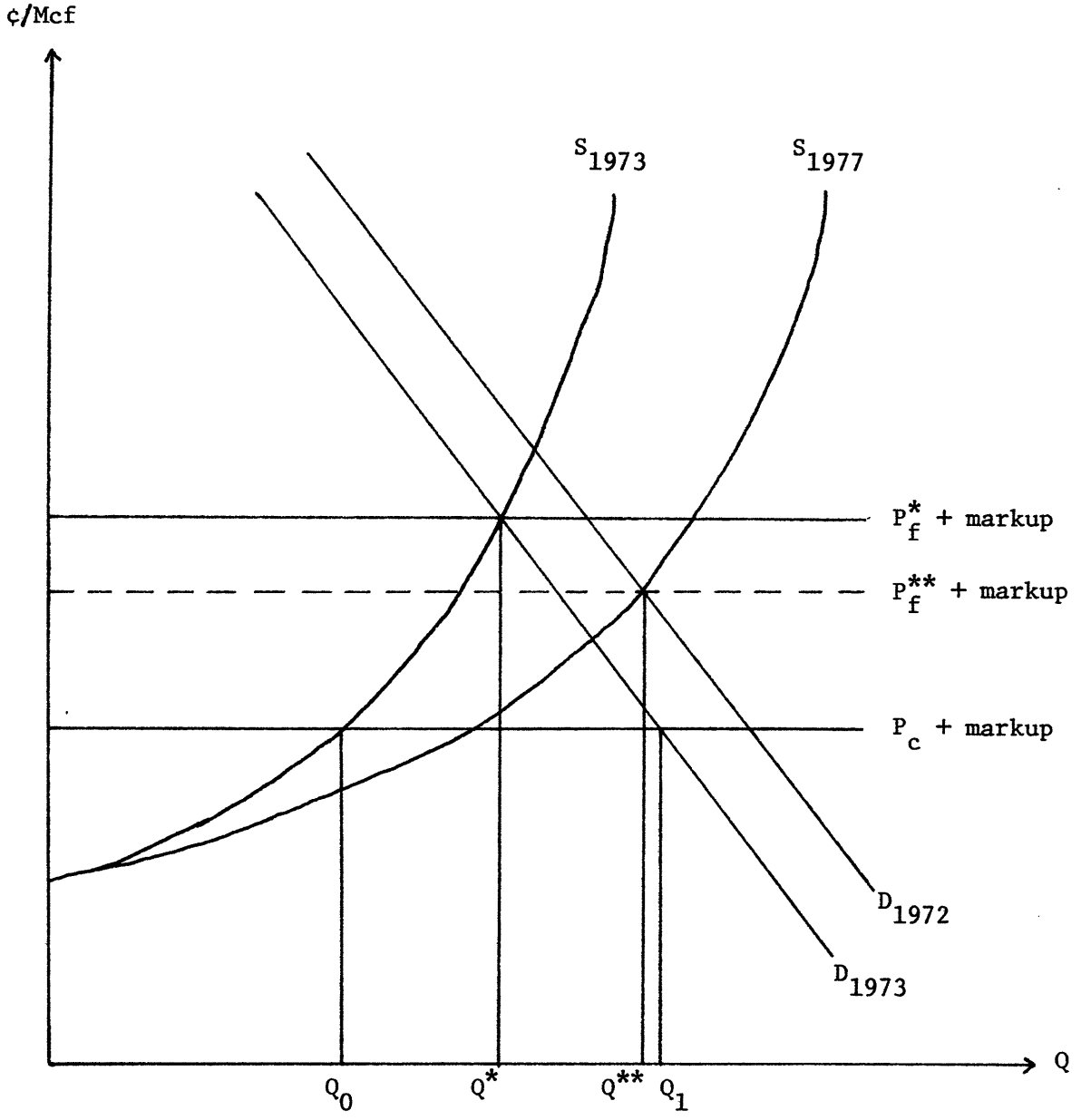
¢/Mcf
S_{1973}
S_{1977}
P_f^* + markup
P_f^{**} + markup
P_c + markup
D_{1972}
D_{1973}
Q
Q_0
Q^*
Q^{**}
Q_1

Figure 5

3. An Econometric Model for Policy Analysis

Most previous econometric studies of natural gas have investigated either demand or supply of gas, but have neglected the simultaneous interaction of these two sides of markets. Balestra, for example, in his classic study of the demand for natural gas by residential and commercial consumers, assumed a perfectly elastic supply curve for production. This assumption was probably justified during the 1950's and 1960's since production of gas for final consumers took place on an "as needed" basis from large stocks of reserves, but it would not continue to be valid during the 1970's, however, as total gas demand exceeds the constraints on production imposed by smaller reserve levels. The supply studies of Erickson and Spann, and Khazzoom, similarly, are admirable attempts at defining and testing some of the relationships that exist in the gas industry, particularly those accounting for reduced reserve levels under price controls. But, to the extent that policies are changed in the future so that markets clear, and demand is once again observed, models of only the supply side of markets will be inadequate to represent the effects of policy. If the industry is to be properly understood, then, production and reserve supply levels of the industry have to be analyzed as a simultaneous system.

The model developed as part of this study consists of a set of simultaneous econometric relationships among several policy-related variables. Variables endogenous to the field market include, on the supply side, non-associated and (oil) associated discoveries of gas reserves, extensions and revisions of associated and non-associated reserves, and wells drilled.

These variables directly or indirectly depend on the field prices paid by pipelines in new contracts for gas. Field prices would be endogenous if demands could clear, but after ceiling prices were set by the F.P.C. in the 1960's, this variable became an exogenous policy variable.

Endogenous variables in the wholesale market include demand for production of gas and wholesale prices for three wholesale delivery sectors: mainline industrial sales, sales for resale that are ultimately industrial, and sales for resale that are ultimately residential and commercial. Throughout the 1960's, wholesale production demand was completely satisfied even though there was excess demand for reserves (of course, reserve-production ratios dropped dramatically during the decade) and thus wholesale demand equations can be estimated from data generated in this period.

An equation for marginal development costs (the "supply curve" for production in field markets), when combined with pipeline wholesale price markup equations, provide the wholesale supply curves for production. This allows us to determine "production out of reserves," as well as possible excess demand by comparing estimated "production out of reserves" with estimated demands for reserves.

There is no single field market, nor is there a single wholesale market in the United States. Producers from around the country do not take their gas to the Chicago Board of Trade in order to make offers of sale to pipelines. Rather, there are several "regional" field markets and several "regional" wholesale markets, and the natural gas industry is characterized by the spatial interrelationships of these markets. This is taken into account by our econometric model. Field reserve and production equations are estimated for supply regions either separately or together with specific variables to account for the regionalization. Wholesale demand equations

are estimated for each of five parts of the country (each part roughly representing a regional market). Gas from each production district in the country is allocated to one or more wholesale consumption regions using the average allocation proportions that prevailed in the past (based on the presumption that many new pipelines will not be built during the 1970's). In this way, excess demand can be computed on a region-by-region basis, as well as for the country as a whole.

3.1 Structure of the Model

The organization of the model is illustrated in Figure 6. Note, however, that this figure leaves out (for simplicity) the spatial interconnections between production districts and regional wholesale markets. In the model as it actually runs, the wholesale prices of gas (for mainline sales and for sales for resale) are computed for each region of the country by taking the wellhead price of gas at the production source and adding a markup based on pipeline mileage and volumetric capacity. When a wholesale consumption region is supplied by more than one production district (as is usually the case), wellhead prices, mileages, and capacities are weighted according to previous actual proportions of production from each district. Let us now look at the individual parts of the model in more detail.

A. The Field Market

Probably the sector of the natural gas industry most difficult to capture in a conceptual model is the supply of new reserves. Most of the current controversy over regulatory policy centers on this sector -- whether or not reserve additions have been too low as a result of past regulatory

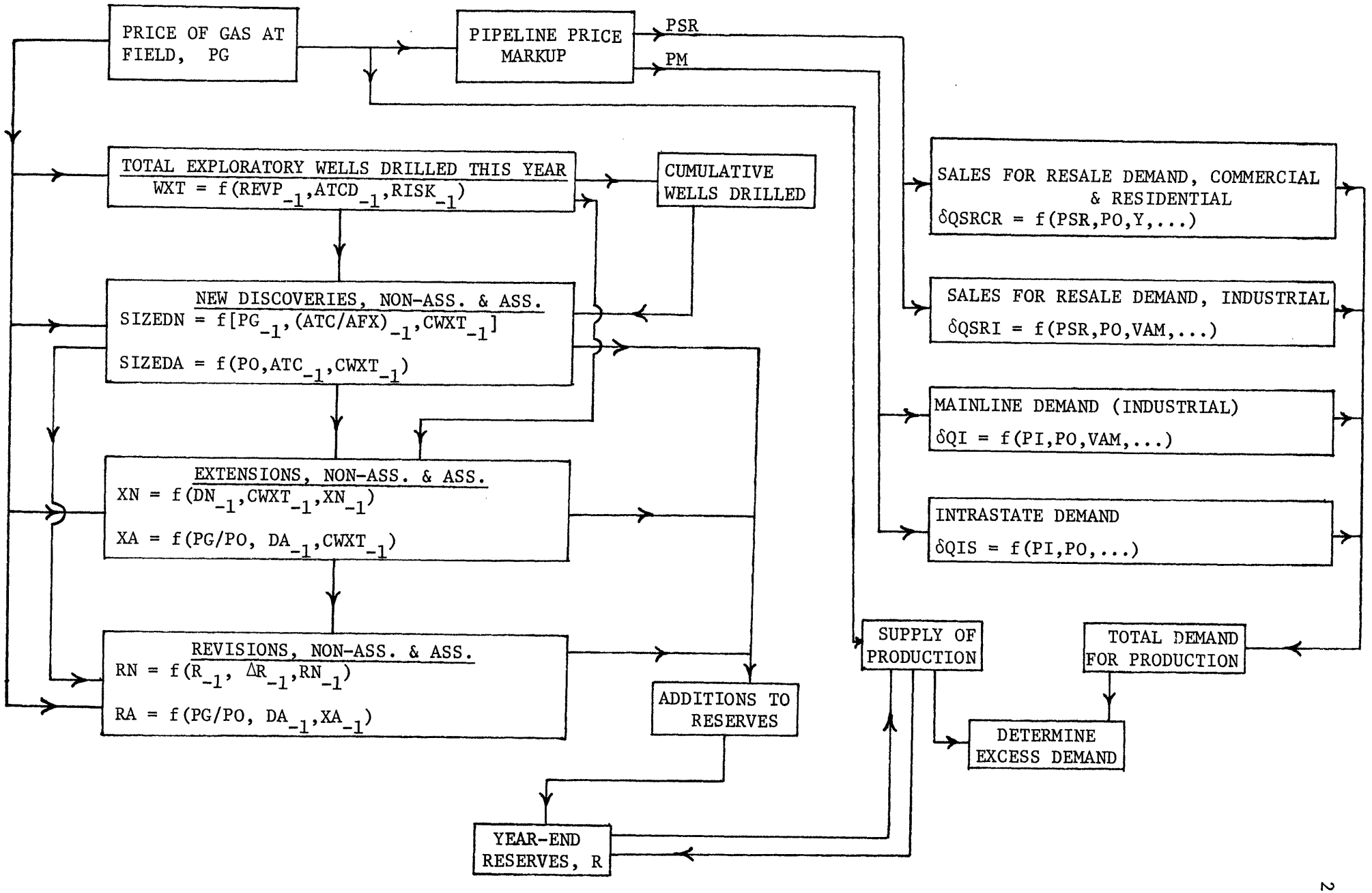

Figure 6: THE MODEL

policy. Actual additions to reserves through new discoveries are realized by a complicated process involving a large number of technological factors, and it may seem naive to try to model the process using a set of simple econometric relationships. Structural equations can be formulated, however, that do link economic and technological variables that are important in gas reserve additions and also describe most simply and directly the regulatory effects.

The major component of new reserve additions consists of new discoveries of both non-associated and associated gas (non-associated gas (N) is dry gas while associated gas (A) includes "dissolved" gas recovered from oil production, as well as "free" natural gas forming a cap in contact with crude oil). In our model, the discovery process begins with the drilling of wells, some of which will be successful in discovering gas, some will be successful in discovering oil (with associated gas), and some will be unsuccessful (i.e., dry holes). The drilling of wells depends largely on economic incentives; in our model, it is dependent upon past revenues from oil and gas production, average drilling costs, and a measure of drilling risk.

The model translates drilling activity into actual discoveries through two size-of-discovery variables, one for non-associated and one for associated gas. The size of discovery variable for non-associated gas, for example, gives for any district and any year the average number of Mcf of gas discovered per well drilled. The size of discovery variables themselves are explained partly by economic variables (e.g., oil and gas prices and drilling costs) but also by a depletion effect, in which extensive well

drilling in the past (measured by cumulative wells drilled) makes it more difficult to discover gas in the present.

Drilling may be divided into two basic modes of behavior, depending on whether it is done extensively or intensively. In extensive drilling, few wells are drilled, but those that are drilled usually go out beyond the frontier of recent discoveries to open up new geographical locations or previously neglected deeper strata at old locations. Typically, this would include drilling farther offshore, or onshore but at very great depth. Here the probability of discovering gas is rather small, but the size of discovery may be comparatively large. When drilling is done intensively, many small wells are drilled in an area that has already proven itself to be a source for gas discovery. Here the probability of discovering gas is larger, but the size of discovery is likely to be very small. In Figure 7, typical probability distributions for discovery size are shown for each mode of drilling behavior. Relative to the intensive drilling mode, discovery size for extensive drilling has a larger expected value but also a larger variance.

The producer who is engaged in exploratory activity has, at any point in time, a choice as to whether any increases in his drilling activity will be extensive or intensive, and this choice will be influenced by changes (or expected changes) in economic variables.[1] The actual influence of economic variables (field prices and drilling costs) will depend on the producer's geological portfolio (i.e., the set of regions over which he

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[1]See F.M. Fisher, Supply and Costs in the U.S. Petroleum Industry.

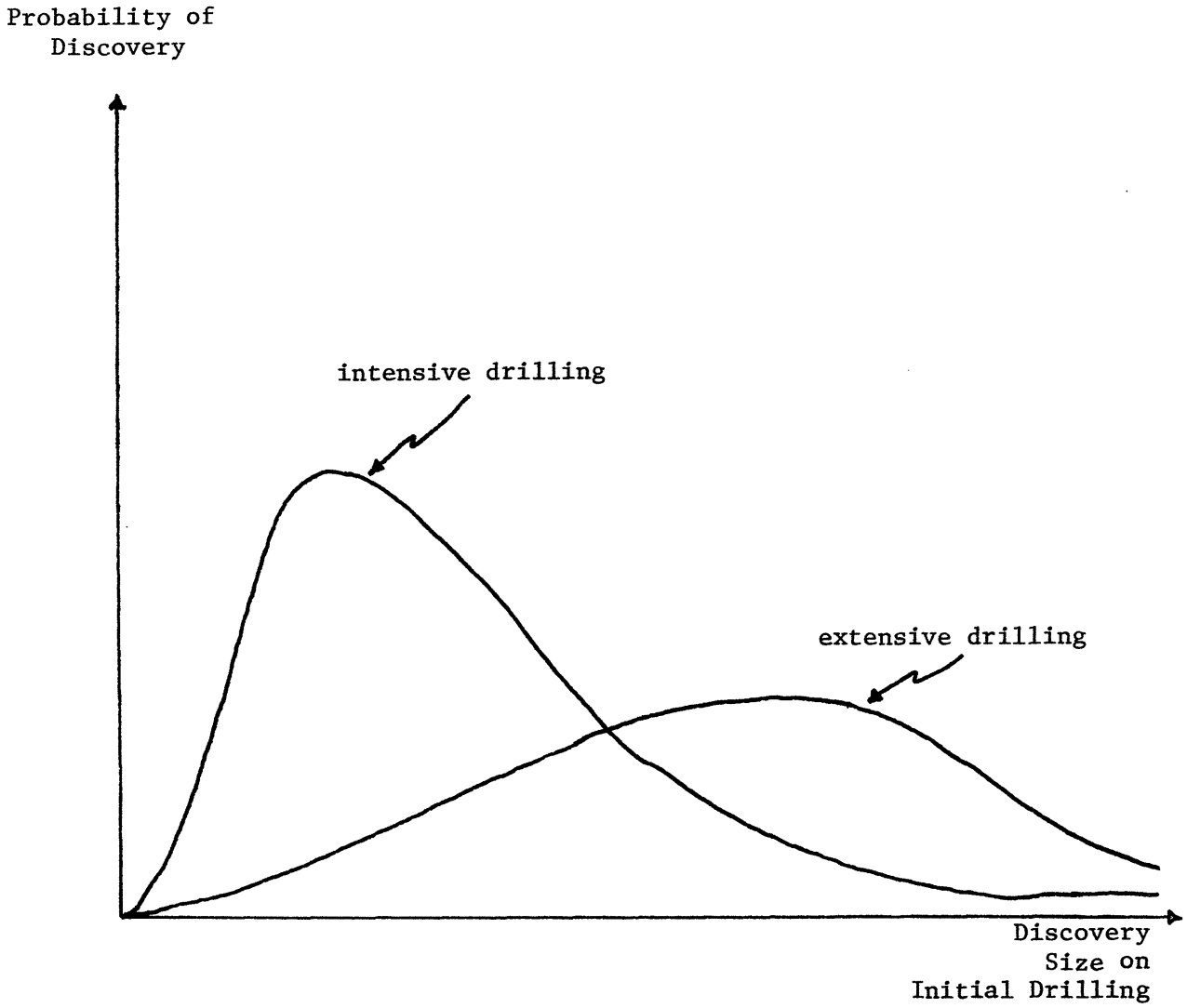

Figure 7: Discovery Distribution

has drilling rights), as well as his own translation of present and past prices and costs into expectations on future prices and costs. Suppose, for example, that drilling costs decrease. As a result, a producer might decide to accept greater risk and drill on the extensive margin, with the result that average discovery size will (ex post) increase. On the other hand, the producer may own partially drilled reservoirs that now are worth drilling out. If this is the case, he might decide to drill on the intensive margin with a resulting ex post decrease in average discovery size. Thus it is not possible a priori to determine whether the effect of a decrease in drilling costs on average discovery size will be positive or negative. The same is true for a change in the price of gas.

Higher gas prices should indeed result in more drilling, but we would expect that over the years success ratios and size of finds will decrease as our finite resource stock begins to get depleted. One may model the exploration and discovery process stochastically as sampling without replacement, so that the expected value of discovery size would decrease as the sampling process went on.[1] It is not our objective to try and predict how big the total stock of gas yet to be discovered is,[2] but we would like to embody a "depletion effect" in our model, at least to the point of being able to extrapolate the long-run decreasing returns to industry size that

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[1] See G. Kaufman, "Sampling without Replacement and Proportional to Random Size," Memorandum II, March 19, 1973.

[2] Industry spokesmen have claimed that higher gas prices result not only in more drilling activity, but also a shift to the extensive mode resulting in larger discovery size. While we would expect higher gas prices to elicit more drilling, it is not clear that the additional drilling will be more extensive. Our results do show a positive relationship between price and discovery size, but with a low elasticity.

have occurred over the past decade. We do this by including cumulative wells drilled as an explanatory variable in our "size of discovery" equations. If the level of drilling activity is the same next year as it is this year, we would expect to see the level of new discoveries drop somewhat, and this is what would indeed happen if discovery size depends negatively on cumulative wells drilled.

Additions to gas reserves can also occur as a result of extensions and revisions of existing fields and pools. Extensions and revisions should also be expected to depend on price incentives, past discoveries of gas, existing reserve levels, and the cumulative effect of past drilling. Extensions are somewhat easier to model than revisions, and actually turn out to be influenced by price incentives, prior discoveries, and the total level of drilling activity.[1] Revisions of established reserve levels are often erratic and difficult to predict. There is some effect from the price of oil relative to gas, but otherwise revisions will simply turn out to be proportional to prior discoveries and reserve levels.

New discoveries, (DN, DA), extensions (XN, XA) and revisions (RN, RA) are combined to form additions to reserves. Aside from losses (L) and changes in underground storage (ΔUS), which we model as a constant percentage of production, the only major subtraction from reserves occurs as a result of production (Q). Thus, for any time t, in a production district j, total gas reserves are given by the identity:

$$R_{t,j} = R_{t-1,j} + DN_{t,j} + XN_{t,j} + RN_{t,j} + DA_{t,j} + XA_{t,j} + RA_{t,j} - Q_{t,j} - L_{t,j} - \Delta US_{t,j} \quad . \tag{1}$$

We see that the supply of new reserves is determined by adding new discoveries, extensions and revisions together and subtracting production

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[1]Extensions can result from either exploratory or development well drilling. Our model does not explain development well drilling, and therefore only exploratory wells are used to explain extensions.

(and also, of course, adjusting for losses and changes in underground storage). If the wellhead price of gas were not regulated, or if regulation were ineffective, then the demand for new reserves could be given by an equation for pipeline offers to buy reserve commitments at specified new contract wellhead prices. Since 1962, however, there has been excess demand for new reserves and thus the demand function for new reserves has not been observable. Instead, the price has been given by the exogenous ceiling price.

B. Production Out of Reserves

The supply of production as a function of price is just the marginal cost (in the short term) of developing existing reserves (e.g., drilling development wells and then operating them) to the point of actual gas production. Clearly, marginal production costs will depend on reserve levels relative to production, and as the reserve-to-production ratio becomes small, we would expect marginal costs to rise sharply.

Let us examine what marginal costs would be corresponding to a production level q out of proved reserves R.[1] Assuming a constant decline rate, a, in percent per year,

$$a = q/R = 1/\text{Reserve-Production ratio} \quad , \tag{2}$$

we can write the proved reserve level as

$$R = q \int_0^\infty e^{-at} dt = q/a \quad . \tag{3}$$

Then for a discount rate δ the "present-Mcf-equivalent" (PME) of a constant production level q is:

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[1]Our thanks to M. Adelman and M. Baughman for their assistance on this part of the model.

$$PME = q \int_0^{\infty} e^{-(a+\delta)t}\, dt = q/(a+\delta) \quad . \tag{4}$$

Now we assume that the development investment, I, needed to obtain the production level q is given by:

$$I = A + ce^{\beta a}q \tag{5}$$

where A is a start-up cost, c is constant over the range of zero well interference, and β is a parameter with value around 10. Thus, when a is small (e.g., the reserve-production ratio is larger than 10), I will be roughly linear in q, but when a becomes larger (e.g., the reserve-production ratio approaches 5), an exponential rise in costs begins to predominate. The marginal development cost (MDC) is then given by:

$$\begin{aligned} MDC &= \frac{dI}{d(PME)} = \frac{dI}{dq} \cdot \frac{dq}{d(PME)} \\ &= \left(\frac{\partial I}{\partial a}\frac{da}{dq} + \frac{\partial I}{\partial q}\right) \cdot \frac{dq}{d(PME)} \end{aligned} \tag{6}$$

$$\begin{aligned} MDC &= \left(\frac{c\beta}{R} e^{\beta a}q + ce^{\beta a}\right) \cdot \frac{(a+\delta)^2}{\delta} \\ &= (\beta a + 1)ce^{\beta a}\frac{(a+\delta)^2}{\delta} \\ &= (\beta a + 1)c\delta e^{\beta a}\left(1+\frac{a}{\delta}\right)^2 \quad . \end{aligned} \tag{7}$$

This marginal cost curve is illustrated in Figure 8 for $\delta = 0.1$, $\beta = 10$, $c = 10$, and $R = 0.2$ trillion Mcf. For small values of a (i.e., large reserve-production ratios), the curve is predominantly quadratic, and when a becomes large, the curve begins to look more like an exponential. We estimate a marginal cost curve (which, when price is set equal to marginal cost, becomes our supply curve for production out of reserves) that is essentially exponential. Aside from the fact that this gives a

better fit to recent data, it is also in keeping with our goal of calculating excess demand for gas under conditions of declining reserve-production ratios.

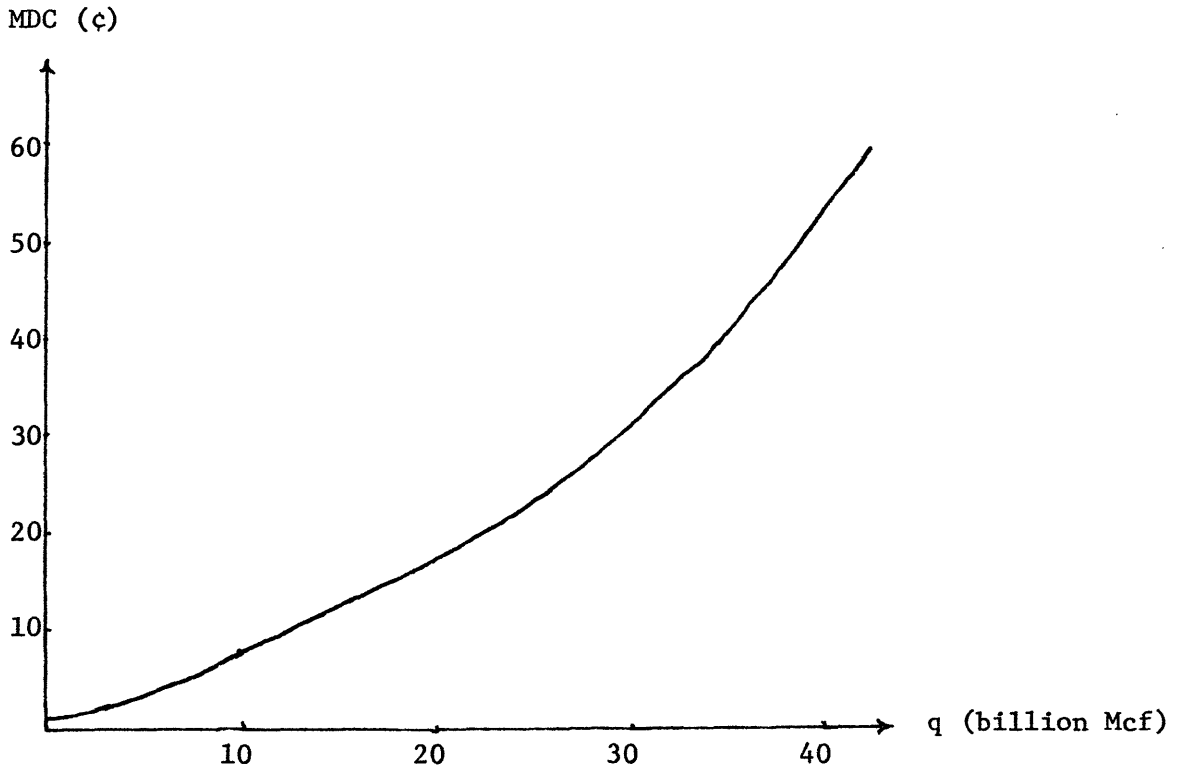

Figure 8: Hypothetical Marginal Cost Curve

C. The Wholesale Market

The supply of production -- determined by what is essentially a marginal cost curve for production out of reserves -- has to be put against demands for that production by companies providing gas to final consumers. The demands for production are approximated by curves fitted on a disaggregated basis, namely by wholesale demand equations for (1) gas sales for resale

(split into commercial-residential gas, and industrial gas on the basis of percentages distributed to these two groups for ultimate consumption), (2) gas sales directly off the pipelines for consumption, and (3) intrastate sales by producers and pipelines to final consumers. The wholesale prices of gas (disaggregated into a "sales for resale" price and a "mainline sales" price) is computed by adding a markup to the field price based on (a) the mileage between the production district and the consuming region, and (b) the volumetric capacity of the pipelines.

The demand equations follow a general formulation, in which the quantity demanded is dependent on wholesale price, the price of alternative fuels, and "market size" variables such as population, income, and investment that determine the number of potential consumers. In all of the equations, the dependent variable will be new demand, δQ, rather than the level of total demand. In the short run, as Balestra has shown for residential gas [2], the level of total demand should be relatively price inelastic and would depend on stock variables that do not change much in time (e.g., the total stock of gas burning appliances for residential gas). New demand, however, should respond to the price of gas and to the price of competing fuels (decisions to buy new appliances, for example, are affected by fuel prices). The new demand for gas, δQ, is made up of the increment in gas consumption $\Delta Q = Q_t - Q_{t-1}$, and of replacement for continuation of old consumption. To find replacement, total residential and commercial gas demand could be considered to be a function of the stock of gas burning appliances, A:

$$Q_t = \lambda \cdot A_t \tag{8}$$

where λ is the (constant) utilization rate. Then, if r is the average rate at which the stock of appliances depreciated, the replacement demand for gas includes $r\lambda A_{t-1}$, and total new demand is

$$\delta Q_t = \Delta Q + r\lambda A_{t-1} \quad . \tag{9}$$

Now substituting (8) into (9) gives:

$$\delta Q_t = \Delta Q_t + rQ_{t-1} \quad . \tag{10}$$

Thus, new demand for gas is the sum of the incremental change in total gas consumption (ΔQ_t) plus the demand resulting from the replacement of old appliances.

Our a priori assumption is that new demand depends on prices and total income (through purchases of new appliances), and that the level of total demand is itself a function of income and population. Thus, we have for residential and commercial demand:

$$\delta QSRCR_{t,k} = f(PSR_{t,k}, PF_{t,k}, Y_{t,k}, \delta Y_{t,k}, \delta N_{t,k}) \tag{11}$$

where PSR is the sales-for-resale wholesale price, PF is a price index of competing fuels, Y is disposable income, and N is population, all in region k, and

$$\delta Y_{t,k} = \Delta Y_{t,k} + rY_{t-1,k} \tag{12}$$

and

$$\delta N_{t,k} = \Delta N_{t,k} + rN_{t-1,k} \quad .^{1} \tag{13}$$

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[1] Balestra [2] distinguishes between two depreciation rates, one for gas appliances and the other for alternative fuel-burning appliances, since lifetimes for appliances using alternative fuels may be different. He then estimates the two depreciation rates by estimating an equation of the form:

$$QSRCR_t = a_0 + a_1 PSR_t + a_2 \Delta N_t + a_3 N_{t-1} + a_4 \Delta Y_{t-1} + a_5 Y_{t-1} + a_6 QSRCR_{t-1}. \tag{14}$$

[continued on next page]

The model is closed by spatially interconnecting production districts with consuming regions. A flow network is constructed which, based on relative flows over the past few years, determines where each consuming region obtains its gas. Average wholesale prices (again both for sales for resale and mainline sales) can thus be computed for each consumption region in the country, since mileages and volumetric capacities are then determined. Wholesale demand (by type) is then also computed for each region of the country. Wholesale demands can be summed to produce total demand for each region of the country, and since we know what the supply of production will be to each region of the country, we can determine excess demand.

3.2 Estimation of the Model

The model was estimated using pooled cross-section and time-series data. The time bounds of the regressions are different for different equations, partly as a result of data limitations but also because of structural change over time in the industry. Wholesale demand equations, for example, were estimated using data only from 1967 to 1971, even though data was available from as far back as 1960, because it was felt that demand elasticities have

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The depreciation rate for gas appliances is then given by $(1-a_6)$. (His results, however, gave an estimated a_6 that was always greater than 1, which cannot be justified theoretically.) The all-fuel depreciation rate comes out of equation (14) as either the ratio a_3/a_2 or a_5/a_4. Thus, the equation is over-identified, and the depreciation rate can be obtained only by estimating (14) subject to the constraint of $a_3/a_2 = a_5/a_4$. (The resulting estimation problem is non-linear, but Balestra uses an iterative method suggested by Houthakker and Taylor [12] to obtain an estimated depreciation rate equal to 0.11.) Rather than attempting to estimate one or more depreciation rates, we will use a single rate assumed to be equal to 0.1, and use this for both industrial and for residential and commercial demand.

changed considerably during the 1960's partly as a result of new air pollution standards.[1]

Cross sections were also different for different equations. Field market equations were estimated by pooling data from all of 19 F.P.C. production districts, while individual sales-for-resale wholesale demand equations were estimated over what were considered to be the proper regional wholesale markets, and thus each used data pooled from five to ten states. District breakdowns and time bounds are summarized for all equations of the model in Table 1.

A. Statistical Results

The regression results described below were obtained using two-stage least squares whenever unlagged endogenous variables appeared on the right-hand side of an equation. All of the equations are linear in form, with the exception of the equation describing production out of reserves, which is logarithmic in the price term (thus marginal production costs are an exponential function of production and reserves). t-statistics are shown in parentheses below each estimated coefficient. Also listed for each equation are the R^2, F-statistic, standard error of the equation, Durbin-Watson statistic, and the mean of the dependent variable. Note that the Durbin-Watson has limited meaning, since error terms may be autocorrelated across time and/or across cross-sections, and these effects are not separated.

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[1] A test of this hypothesis and a more detailed study of demand will appear in a future paper.

Table 1: Cross-Sections and Time-Bounds for the Model's Stochastic Equations

Equations	Districts Pooled	Time Bounds
Wells (WXT)	All 19 F.P.C. Production Districts*	1964 - 1971
Discovery Size (DIZEDN, SIZEDA)	All 19 F.P.C. Production Districts	1964 - 1971
Extensions & Revisions (XN, XA, RN, RA)	All 19 F.P.C. Production Districts	1964 - 1971
Production From Reserves (QS)	California, Colorado, Wyoming, New Mexico North, Texas 1, 2, 3, 4, 6, 9, 10, Louisiana North, New Mexico South, Mississippi, West Virginia, Kansas, Oklahoma	1962 - 1971
Production from Reserves	Louisiana South	1965 - 1971
Price Markups (PSR, PM)	40 Sales-for-Resale Regions (see below), plus 15 Mainline Sales Regions (see below)	1956 - 1969
Sales-for-Resale Demand (Residential/Commercial and Industrial)		
Northeast	New England, New Jersey, New York, Pennsylvania, Ohio, Maryland+Delaware+Wash.D.C., Virginia, West Virginia	1967 - 1970
North Central	Illinois, Indiana, Michigan, Wisconsin, Iowa, Minnesota, Missouri, Nebraska, South Dakota	1967 - 1970
West	Arizona, Colorado, Idaho, Nevada, New Mexico, Utah, Wyoming, California, Washington, Oregon	1967 - 1970
South Central	Kansas, Arkansas, Oklahoma, Texas, Mississippi, Louisiana	1967 - 1970
Southeast	Florida, Georgia, North Carolina, South Carolina, Alabama, Kentucky, Tennessee	1967 - 1970
Mainline Demand (Industrial)		
Gas-Producing States	Colorado+Wyoming, Kansas, Kentucky+Ohio+Pennsylvania+West Virginia, Louisiana, Mississippi, Oklahoma+Texas	1967 - 1970
Non-Producing States	Alabama+Georgia, Arizona, Arkansas, Florida, Illinois, Iowa+ Nebraska, Minnesota, Missouri, Tennessee	1967 - 1970
Intrastate Sales	California, New Mexico, West Virginia, Kansas, Texas, Oklahoma, Louisiana	1967 - 1970

* These include Texas 1, 2, 3, 4, 6, 9, 10, California, Colorado-Utah, Kansas, Louisiana North, Louisiana South, Montana, Mississippi, New Mexico North, Permian (= New Mexico South+Texas 7C + Texas 8+ Texas 8A), Oklahoma, Pennsylvania, West Virginia+Kentucky, Wyoming.

One of the difficulties in constructing a model of this sort is that one must work under the constraints imposed by data limitations. Data for many variables is either difficult or else impossible to obtain, particularly for years prior to 1966. In addition, much of the data is extremely noisy. As a result, a good deal of compromise was often required in estimating equations between functional forms that are theoretically pleasing and those that lend themselves to the existing data. This should be kept in mind when interpreting the estimation results.

A.1 Field Market Equations

The field market portion of the model contains seven stochastic equations that explain total exploratory well drilling (WXT), non-associated and associated average discovery size (SIZEDN, SIZEDA), extensions (XN, XA), and revisions (RN, RA). Non-associated and associated new discoveries (DN, DA) can be determined from the two identities:

$$DN_{t,j} = SIZEDN_{t,j} \cdot WXT_{t,j} \tag{15}$$

$$DA_{t,j} = SIZEDA_{t,j} \cdot WXT_{t,j} \tag{16}$$

and the supply of new reserves is then determined from the identity in equation (1).

Exploratory well drilling responds to three economic incentives, all of which are exogenous to the model. The first of these is total revenues (deflated by a GNP price index), REVD, from sales of both oil and gas at the wellhead. Exploratory drilling may result in the discovery of either gas or oil, and so total revenues is used as an explanatory variable. Note that changes in the price of gas (or the price of oil) can affect drilling activity through this revenue variable.

Average total drilling costs (also in deflated terms), ATCD, is a second explanatory variable; rising costs are expected to have a negative impact on drilling. The third explanatory variable, RISKV, provides a measure of relative risk between different regions. It is a purely cross-sectional variable that does not change in time, and is the sample variance (measured over recent years) of payoff size in each district. Finally, three dummy variables are introduced (DDA, DDB, DDC) to account for heterogeneity among four broadly defined regional field markets in the United States. The estimated equation is:

$$\begin{aligned} WXT = {} & \underset{(8.60)}{385.03} + \underset{(3.23)}{818.54}\ DDA + \underset{(1.10)}{188.22}\ DDB + \underset{(3.37)}{152.62}\ DDC + \underset{(2.30)}{2.31\text{x}10^{-4}}\ REVD_{t-1} \\ & - \underset{(-4.08)}{.00398}\ ATCD_{t-1} - \underset{(-2.75)}{2.087}\ RISKV \end{aligned} \tag{17}$$

$R^2 = .466$ F = 16.12 S.E. = 201.5 DW = 0.31 Mean(WXT) = 356.04

Here it can be seen that "cash flow" (as measured by $REVD_{t-1}$) has a positive effect on drilling, while costs and risk have negative effects. All three effects are statistically significant. Thus, drilling increases as lagged prices and finds increase and as lagged costs and risk decrease.

Economic variables influencing the size of non-associated discoveries per well include the wellhead price of gas, PG, and average drilling costs per foot, ATC/AFX. As explained earlier, the signs of these variables cannot be predicted *a priori*. A third explanatory variable is the cumulative number of wells drilled, CWXT. This is expected to have a negative impact on discovery size since it represents a depletion effect. Finally, the lagged dependent variable is added to the equation, as well as the three district dummy variables. The final equation is:

$$SIZEDN = \underset{(-1.69)}{-634.59} + \underset{(3.42)}{1370.7}\ DDA + \underset{(1.70)}{627.65}\ DDB + \underset{(3.87)}{613.08}\ DDC + \underset{(1.96)}{34.66}\ PG_{t-1}$$

$$+ \underset{(1.05)}{14.88}\ ATC_{t-1}/AFX_{t-1} - \underset{(-1.36)}{0.060}\ CWXT_{t-1} + \underset{(5.38)}{0.390}\ SIZEDN_{t-1} \qquad (18)$$

$R^2 = .633$ F = 22.9 S.E.= 580.1 DW = 1.30 Mean(SIZEDN) = 705.8.

The equation explaining the size of associated discoveries has the same form, except that the price of oil, PO, is used instead of the price of gas, and average drilling costs are not computed on a per foot basis:

$$SIZEDA = \underset{(1.40)}{38.34} + \underset{(2.99)}{115.08}\ DDA + \underset{(1.78)}{35.11}\ DDB + \underset{(3.23)}{26.30}\ DDC - \underset{(-1.21)}{9.37}\ PO +$$

$$+ \underset{(0.95)}{1.198\text{x}10^{-4}}\ ATC_{t-1} - \underset{(-1.69)}{.0041}\ CWXT_{t-1} + \underset{(2.88)}{0.2655}\ SIZEDA_{t-1} \qquad (19)$$

$R^2 = .731$ F = 36.2 S.E.= 31.87 DW = 1.83 Mean(SIZEDA) = 42.46.

These two reserves equations together show strong lag effects (in the coefficient of $SIZEDN_{t-1}$), cost effects, and depletion effects (although the coefficient of depletion is not statistically significant). The price effects are in opposite directions. The price of gas has a strong positive effect on size of non-associated discoveries while the price of oil has a negative (but insignificant) effect on the size of associated discoveries. These effects can occur in this combination because of aggregation of intensive and extensive drilling across districts; their net impact on discoveries, however, is likely to increase discoveries as prices increase.

Extensions of non-associated gas depend on the ratio of gas to oil prices (relatively higher gas prices are a stimulus to extend gas rather than oil fields and total exploratory drilling. Exploratory drilling is used as a proxy for total exploratory <u>and</u> development drilling; extensions also result from the drilling of development wells, but this variable is not explained by the model. The

equation also includes district dummy variables to account for the significant cross-sectional heterogeneity.

$$XN = \underset{(-1.43)}{-5.086\text{x}10^5} + \underset{(5.89)}{1.435\text{x}10^6}\ DDA + \underset{(10.95)}{3.142\text{x}10^6}\ DDB + \underset{(1.45)}{1.732\text{x}10^5}\ DDC +$$

$$+ \underset{(2.36)}{521.02}\ WXT_{t-1} + \underset{(1.32)}{77251.0}\ PRATIO_{t-1} \qquad (20)$$

$R^2 = .648$ $F = 44.9$ $S.E. = 5.85\text{x}10^5$ $DW = 0.62$ $Mean(XN) = 4.22\text{x}10^5$

The equation for extensions of associated gas is similar in form, except that associated discoveries replaces non-associated discoveries, and the ratio of the price of gas to the price of oil is included as an explanatory variable that results in price-responsive directionality in drilling.

$$XA = \underset{(0.71)}{36480} + \underset{(3.63)}{0.946}\ DA_{t-1} + \underset{(1.69)}{9.459}\ CWXT_{t-1} - \underset{(-0.90)}{7611}\ PRATIO + \underset{(5.07)}{0.409}\ XA_{t-1} \qquad (21)$$

$R^2 = .565$ $F = 33.13$ $S.E. = 8.89\text{x}10^4$ $DW = 2.47$ $Mean(XA) = 5.81\text{x}10^4$

Revisions of non-associated gas (RN) depend positively on the previous year's total reserves of gas (YT), and negatively on the <u>change</u> in the previous year's reserves of gas. Large short run increases in reserves usually limit revisions in the following year (which apply more to established discoveries), but in the long run a higher level of reserves results in a higher average level of revisions.

$$RN = \underset{(-0.64)}{-35903} + \underset{(2.12)}{.0062}\ YT_{t-1} - \underset{(-4.66)}{.0242}\ \Delta YT_{t-1} + \underset{(5.28)}{0.368}\ RN_{t-1} \qquad (22)$$

$R^2 = .348$ $F = 20.49$ $S.E. = 4.80\text{x}10^5$ $DW = 1.70$ $Mean(RN) = 0.69\text{x}10^5$

Note that the coefficient of the autoregressive term (RN_{t-1}) is about 0.37, and thus the <u>long run</u> impact on revisions resulting from an increase in re-reserves of 1 Mcf is approximately equal to:

$$\frac{1}{1 - .37}\ (.0062) = .01 \text{ Mcf}$$

since there is no long run effect from the ΔYT_{t-1} term. Thus, a one Mcf increase in the <u>stock</u> of reserves implies about a .01 Mcf per year increase in the <u>flow</u> of non-associated revisions.

Associated revisions (RA) are extremely erratic and difficult to explain using a simple linear regression model. There seems to be no relationship between this variable and lagged reserves of gas, mostly because associated revisions are linked more closely to oil reserves (which are not explained in this model). We modeled associated revisions by relating it to the previous year's associated discoveries and associated extensions, and the gas-to-oil price ratio, although the relationship is somewhat dubious:

$$RA = \underset{(0.95)}{2.178\text{x}10^5} + \underset{(2.67)}{3.185}\ DA_{t-1} + \underset{(1.28)}{0.450}\ XA_{t-1} - \underset{(-1.1)}{42319}\ PRATIO \qquad (23)$$

$R^2 = .186$ F= 7.85 S.E.= $4.06\text{x}10^5$ DW= 1.32 Mean(RA)= $0.70\text{x}10^5$.

A.2 Production Out of Reserves

Two equations are estimated to predict the supply of production out of reserves, one for Louisiana South, and another for the remainder of the U.S. South Louisiana is a large producing region with cost characteristics somewhat different from the rest of the country, and is therefore treated separately. Although data was available from 1955 to 1971, the nation-wide production equation was estimated using only data from 1965 to 1971, since it was only in these years that production approached full short term capacity. The South Louisiana equation, however, is estimated over the range 1962 to 1971 in order to have a sufficient number of degrees of freedom (only one production district is involved, and so there are only as many data points as there are years).

In both equations, total production Q is regressed against the log of the wellhead price PG and against total reserves YT. This yields a supply

of production equation of the form:

$$PG_{t,j} = \alpha_0 e^{\alpha_1 Q_{t,j} - \alpha_2 YT_{t,j}} \tag{24}$$

with α_0, α_1, and α_2 all positive. This approximates (for reserve-production ratios less than 10) the marginal cost curve of equation (7). The nation-wide equation also contains two regional dummy variables, one for the Permian region (DDB) and the second for the region including Oklahoma, Kansas, and Texas Railroad Commission Districts 2, 3, and 4 (DDC). These dummy variables help account for district heterogeneity that remains even after South Louisiana is excluded from the sample.

The estimated equations are shown below:

United States, excluding South Louisiana (1965-1971):

$$\begin{aligned} Q = & \underset{(-1.30)}{-5.053\text{x}10^5} + \underset{(16.10)}{1.823\text{x}10^6}\ DDB + \underset{(7.43)}{5.879\text{x}10^5}\ DDC + \underset{(1.85)}{2.4755\text{x}10^5}\ \log(PG) \\ & + \underset{(5.57)}{0.0240}\ YT \end{aligned} \tag{25}$$

$R^2 = .838$ F= 122.5 S.E.= $2.59\text{x}10^5$ Mean(Q)[1]= $8.117\text{x}10^5$

South Louisiana (1962-1971):

$$Q = \underset{(-11.25)}{-4.663\text{x}10^7} + \underset{(9.16)}{1.0465\text{x}10^7}\ \log(PG) + \underset{(8.45)}{0.2576}\ YT \tag{26}$$

$R^2 = .964$ F= 79.7 S.E.= $4.53\text{x}10^5$ Mean(Q) = $4.941\text{x}10^6$

Both of these equations show positive and significant effects of prices and total reserves. Thus, with higher prices, both short and long run production should increase (as in Figures 5 and 8).

A.3 Wholesale Price Markups

We assume that as long as pipelines are operating within their capacity, marginal transmission costs are a constant function of mileage M_k and volumetric capacity V_k of the lines transmitting to region k. The wholesale price equations thus have the simple form:

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[1]This mean pertains to an average district, since we are pooling cross-section and time series data.

$$PSR_{t,k} - \overline{PG}_{t,k} = f(M_{t,k}, V_{t,k}) \tag{27}$$

for price on "sales for resale" to retail gas utilities and

$$PM_{t,k} - \overline{PG}_{t,k} = f(M_{t,k}, V_{t,k}) \tag{28}$$

for price on "mainline" sales to industrial buyers. Here, $\overline{PG}_{t,k}$ is the "roll-in" wellhead price for wholesale region k determined by averaging the wellhead prices from flowing production in those regions which feed pipelines that transmit gas to region k. The mileage variable $M_{t,k}$ and the capacity variable $V_{t,k}$ are similarly defined, i.e., in terms of the average values of these variables from production regions to the wholesale market region k. The "markup" is the excess of the price over field costs allowed by competition and the Commission, but as shown by the size of coefficients of the independent variables in marginal transmission costs. The "determined" price is approximated by the regression equation coefficients.

Both of the explanatory variables M and V have been roughly constant in time over the past decade or two, so that we are actually running cross-section regressions resulting in constant markups. For sales for resale, the wholesale price is given by:

$$PSR = PG + \underset{(18.28)}{12.561} + \underset{(18.66)}{0.712}\, M - \underset{(-10.57)}{3.3185\times10^{-4}}V \tag{29}$$

$R^2 = .561$ $\quad F = 356.2$ $\quad S.E. = 5.823$ $\quad DW = 2.25$.

Note that the coefficient of volumetric capacity V is negative, since a larger capacity implies lower average costs. For mainline sales, our markup equation is given by:

$$PM = PG + \underset{(4.80)}{3.080} + \underset{(18.29)}{1.079}\, M \tag{30}$$

$R^2 = .739$ $\quad F = 334.6$ $\quad S.E. = 3.04$ $\quad DW = 1.90$

The capacity variable was found to be statistically insignificant, and therefore was not included in this equation.

A.4 Wholesale Demand for Gas

Wholesale demand is broken into three major categories: sales-for-resale demand, mainline sales demand, and intrastate demand. Sales-for-resale demand is further broken down into gas that ultimately is resold for residential/commercial consumption and gas for industrial consumption, and for each category separate equations are estimated for each of five regions of the country. Mainline sales (which are assumed to be mostly industrial) is determined by two equations, the first estimated by pooling data from gas-producing states, and the second estimated using data from non-producing states. The reason for this separation is that in gas-producing states interstate mainline sales compete with intrastate mainline sales, and as a result demand elasticities will differ from those in non-producing states. Intrastate sales are explained with a single equation by assuming that all intrastate sales are the same as mainline industrial sales, so that the mainline wholesale price PM is an explanatory variable.

New or additional demand $\delta Q = \Delta Q + rQ_{t-1}$ is used as the dependent variable in all equations. We have chosen a single depreciation rate r equal to 0.1, based on the assumption that gas-burning equipment has an average lifetime of ten years. Explanatory variables besides the price of gas include the wholesale price of oil (POIL), income (Y), population (N), value added in manufacturing (VAM), capital investment by industry (K), and a price index of alternate fuels (PALT).

Sales-for-resale demand equations are presented for each market region below. In the South Central and Southeast regions, residential/commercial

and industrial sales are aggregated together. Prices have been very low and demand has fluctuated considerably in these regions, making it difficult to obtain stable estimates of demand elasticities on a disaggregated basis. All equations are estimated over the time bounds 1967-1970.

Northeast - Residential/Commercial

$$\delta QSRCR = \underset{(-0.89)}{-11501.4} + \underset{(2.47)}{2.885}\ \delta Y + \underset{(1.58)}{27101.2}\ POIL + \underset{(3.29)}{0.3667}\ \delta QSRCR_{t-1} \qquad (31)$$

$R^2 = .525$ $F = 10.3$ $S.E. = 1.94 \times 10^4$ $Mean(\delta QSRCR) = 3.13 \times 10^4$

Northeast - Industrial

$$\delta QSRI = \underset{(3.27)}{56682.4} - \underset{(-3.24)}{1.3724 \times 10^5}\ PSR + \underset{(4.21)}{1.5336}\ VAM + \underset{(1.55)}{0.1852}\ \delta QSRI_{t-1} \qquad (32)$$

$R^2 = .628$ $F = 15.7$ $S.E. = 1.28 \times 10^4$ $Mean(\delta QSRI) = 2.16 \times 10^4$

North Central - Residential/Commercial

$$\delta QSRCR = \underset{(2.24)}{65927.4} - \underset{(-3.20)}{2.656 \times 10^5}\ PSR + \underset{(11.09)}{13.417}\ \delta Y + \underset{(1.19)}{41268.7}\ POIL \qquad (33)$$

$R^2 = .822$ $F = 49.3$ $S.E. = 1.60 \times 10^4$ $Mean(\delta QSRCR) = 3.52 \times 10^4$

North Central - Industrial

$$\delta QSRI = \underset{(0.96)}{29858.7} - \underset{(-1.94)}{1.752 \times 10^5}\ PSR + \underset{(1.42)}{55241.4}\ POIL + \underset{(2.74)}{1.765}\ VAM + \underset{(4.44)}{0.6450}\ \delta QSRI_{t-1}$$

$R^2 = .769$ $F = 25.8$ $S.E. = 1.70 \times 10^4$ $Mean(\delta QSRI) = 3.47 \times 10^4$ (34)

West - Residential/Commercial

$$\delta QSRCR = \underset{(0.72)}{5542.3} - \underset{(-0.99)}{2.446 \times 10^4}\ PSR + \underset{(17.41)}{37.79}\ \delta N \qquad (35)$$

$R^2 = .891$ $F = 151.3$ $S.E. = 8.65 \times 10^3$ $Mean(\delta QSRCR) = 12.18 \times 10^3$

West - Industrial

$$\delta QSRI = \underset{(0.54)}{8737.0} - \underset{(-0.78)}{4.069 \times 10^4}\ PSR + \underset{(13.95)}{87.52}\ K \qquad (36)$$

$R^2 = .840$ $F = 97.3$ $S.E. = 1.82 \times 10^4$ $Mean(\delta QSRI) = 1.93 \times 10^4$

South Central - Total

$$\delta QSRT = \underset{(1.92)}{4535.3} + \underset{(1.99)}{10.06}\ K + \underset{(2.94)}{0.461}\ \delta QSRT_{t-1} \tag{37}$$

$R^2 = .383$ F = 12.1 S.E.= 1.04×10^4 Mean(δQSRT) = 1.30×10^4

Southeast - Total

$$\delta QSRT = \underset{(2.03)}{23206.8} - \underset{(-1.46)}{4.161 \times 10^4}\ PSR + \underset{(4.53)}{0.727}\ \delta QSRT_{t-1} \tag{38}$$

$R^2 = .490$ F = 12.0 S.E.= 1.01×10^4 Mean(δQSRT) = 2.89×10^4

Mainline industrial demand equations are shown below, estimated separately for gas-producing and non-producing states.

Mainline Sales - Producing Regions

$$\delta QM = \underset{7.21)}{86703.0} - \underset{(-7.28)}{3.869 \times 10^5}\ PM + \underset{(6.32)}{1.205 \times 10^5}\ PALT \tag{39}$$

$R^2 = .754$ F = 29.2 S.E.= 1.2×10^4 Mean(δQM) = 3.0×10^4

Mainline Sales - Non-Producing Regions

$$\delta QM = \underset{(1.68)}{30050.5} - \underset{(-2.65)}{1.155 \times 10^5}\ PM + \underset{(3.07)}{7.357 \times 10^4}\ PALT \tag{40}$$

$R^2 = .438$ F = 12.9 S.E.= 8.76×10^3 Mean(δQM) = 12.13×10^3

Finally, an intrastate demand equation has been estimated as follows:

$$\delta QINTRA = \underset{(2.92)}{2.614 \times 10^5} - \underset{(-3.28)}{1.137 \times 10^6}\ PM + \underset{(1.63)}{1.822 \times 10^5}\ POIL + \underset{(3.65)}{117.85}\ K \tag{41}$$

$R^2 = .494$ F = 7.81 S.E.= 1.06×10^5 Mean(δQINTRA) = 1.02×10^5

These equations show negative price effects on demands, in all regions except the Northeast (where gas prices are probably too high) and the South Central (where gas prices are too low). Alternative fuel prices are important in determining mainline industrial sales. Size of market variables, such as consumer incomes or industrial investment or output, do not appear to be consistent causal factors in all sectors of the national gas market.

B. Interregional Flows of Gas

In order to calculate estimates of excess demand by consuming region (and under-production by production district), we must have some estimate of how gas flows from the wellhead to the point of final consumption. We do this at an aggregate level using the demand regions W, NE, NC, SE, SC and production regions, P1, P2, P3, P4, P5, P6, P7, P8, as defined below:

W: West - Arizona, California, Oregon, Washington, Idaho, Wyoming, Nevada, Utah, Colorado, New Mexico
NE: Northeast - New England, New York, New Jersey, Pennsylvania, Ohio, West Virginia, Kentucky, Maryland (and Delaware), Virginia
NC: North Central - South Dakota, Nebraska, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana
SE: Southeast - Tennessee, Alabama, North Carolina, South Carolina, Georgia, Florida
SC: South Central - Kansas, Texas, Arkansas, Oklahoma, Louisiana, Mississippi
P1: Texas Railroad District 10, Oklahoma, Kansas
P2: New Mexico San Juan, New Mexico Permian, Texas 8, Texas 8A, Texas 7C
P3: Texas 1, Texas 9, Texas 5, Texas 7C
P4: Texas 2, Texas 3, Texas 4, Texas 6, Louisiana North, Louisiana South, Mississippi
P5: Colorado, Wyoming
P6: Canada (exogenous production)
P7: California
P8: Kentucky, Ohio, Pennsylvania, West Virginia .

The flows of gas from production region to consuming region as estimated for 1970 are shown in Figure 9. In each box is an integer which represents the flow from the particular production region (row) to the consuming region (column). The decimal to the left of this number (f_{jk}) represents the fraction of the consuming region's demand which comes from that production region, while the decimal to the right (g_{jk}) represents the fraction of gas from that production district going to a particular consuming region. Then, letting Q_j

Figure 9: Gas Flows - 1970

Sales f_{jk} g_{jk}	W	NE	NC	SE	SC	Total Production
P1	235 .069 .055	82 .020 .019	1765 .413 .418	0 .000 .000	2136 .247 .506	4218 .192
P2	1675 .497 .512	0 .000 .000	646 .151 .197	0 .000 .000	955 .110 .292	3276 .149
P3	0 .000 .000	14 .003 .043	60 .014 .184	14 .009 .043	237 .027 .729	325 .014
P4	0 .000 .000	3630 .888 .296	1776 .416 .145	1530 .990 .125	5293 .607 .428	12,229 .558
P5	478 .141 .959	0 .000 .000	20 .004 .400	0 .000 .000	0 .000 .000	498 .022
P6	305 .090 1.00	0 .000 .000	0 .000 .000	0 .000 .000	0 .000 .000	305 .013
P7	676 .200 1.00	0 .000 .000	0 .000 .000	0 .000 .000	0 .000 .000	676 .030
P8	0 .000 .000	359 .087 1.00	0 .000 .000	0 .000 .000	0 .000 .000	359 .016
Total Demand	3369 .153	4085 .186	4267 .194	1544 .070	8621 .393	21,886 1.000

equal production in district j and letting D_k equal demand in region k, we can calculate:

(1) $Q_j - \sum_k [f_{jk}D_k]$ = production shortage in producing region j

and

(2) $D_k - \sum_j [Q_j g_{jk}]$ = excess demand in consumption region k .

The numbers in Figure 8 were derived from F.P.C. data as follows:

(1) The F.P.C. Sales by Producers of Natural Gas to Interstate Pipeline Companies 1970 was used to determine for each company the distribution of sales from each production region.

(2) These purchases were then distributed to the various consuming regions (if they went to more than one) by an estimation process based on the F.P.C. Form 2 Reports on Sales for Resale and Mainline Industrial Sales by interstate pipeline companies and through the use of the F.P.C. map, Principal Natural Gas Pipelines in the United States 1968. In many instances the companies purchases and sales were divided into several non-overlapping flows. These were then easy to determine. In others, it was necessary to estimate the actual flows since more than one production region might be tapped for sales to more than one consuming region along the same pipeline. In these cases, judicious use of the Form 2 data was necessary to resolve the data. It is believed that the estimates made are close enough to the correct ones to make estimates of excess demand within the accuracy desired.

(3) The third step was to determine the size of intrastate and field sales[1]

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[1]Field sales are sales to an oil producer for pressuring purposes. It also includes pipeline fuel.

to each region. This was done by determining the difference between the total interstate sales coming from each production region and the value given for total production from that region by the AGA's Reserves of Crude Oil. The difference was then added as intrastate and field sales to the demand region containing the production region. In only one case (Permian Basin) was it necessary to split the intrastate production into two demand regions. This was accomplished by using the Bureau of Mines Consumption of Natural Gas data (Bureau of Mines, Minerals Yearbook) for 1970 and previous to determine total consumption for New Mexico. The quantity of intrastate sales necessary to bring New Mexico's total consumption up to the proper level was added into the proper box. The rest was added to the South Central region.

This completed the flow table from which the fractions were easily calculated.

3.3 Simulation of the Model

The model will be used to predict the response over time of production supply and demand to a changing regulated field price. In order to help interpret (and also evaluate) these predictions, it is useful to examine a simulation of the model performed over an historic time period. If, for example, this simulation showed an increasingly upward bias in production supply over time, this could be taken into account when interpreting the model's predictions for future excess demand.

The model was simulated over the period 1965-1971,[1] using historical values for all of the exogenous variables, including regional wellhead prices.

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[1]This time period represents the intersection of time periods for which data is available for each variable in the model.

The results of this simulation are shown for production supply and demand and for the wholesale price in Table 2. In addition to listing the simulated values, actual values, and errors for each variable, the mean and root-mean-square (RMS) simulation errors are also calculated.

Note that simulated production supply is about 4 trillion cubic feet larger than the actual production levels between 1966 and 1969 (the mean error is less than 3 trillion cubic feet, but that is because the 1965 error is negative). Production demand is also overestimated, with an error that grows from about 1 trillion cubic feet in 1966 to about 2.5 trillion cubic feet in 1970. Although the mean demand error is smaller than that for supply, the demand error is growing at a rate that would make it equal to the supply error by 1972 or 1973. At least part of the reason for the overestimate of demand is the underestimate of the average wholesale price. The simulated wholesale price is about one penny too low from 1965 to 1969, and two pennies too low in 1970.

It would appear, then, that the model's forecasts of excess demand should be viewed as having a margin of error (probably negative) of at least one or two trillion cubic feet. This should be taken into account when interpreting the policy analyses that are presented in the next section. Excess demand may turn out to be somewhat larger than what we forecast, and the price increases necessary to eliminate excess demand may actually be a few cents higher than those which we present.

Table 2: Historic Simulation of Production Supply and Demand

Year	(1) Simulated Production Supply (trillions of cu.ft.)	(2) Simulated Production Demand (trillions of cu.ft.)	(3) Actual Production (trillions of cu.ft.)	(4) Supply Error [(1)-(3)]	(5) Demand Error [(2)-(3)]	(6) New Contract Field Price (cents)	(7) Simulated Average Wholesale Price (cents)	(8) Actual Average Wholesale Price (cents)	(9) Average Wholesale Price Error [(7)-(8)]
1965	1.7	1.5	1.9	-1.9	0.6	16.8	27.1	28.2	-1.1
1966	1.9	1.6	1.5	3.8	0.8	16.9	27.1	28.2	-1.1
1967	2.0	1.8	1.6	3.9	1.6	17.3	27.0	27.9	-0.9
1968	2.1	2.0	1.7	4.2	1.8	17.7	27.2	27.8	-0.6
1969	2.2	2.1	1.8	4.3	1.9	18.6	27.4	28.5	-1.1
1970	2.3	2.3	NA	NA	2.4	20.9	27.8	29.9	-2.0

Mean Supply Error = 2.87

RMS Supply Error = 3.76

Mean Actual Supply = 17.5

Mean Demand Error = 1.57

RMS Demand Error = 1.69

Mean Actual Demand[1] = 17.3

Mean Wholesale Price Error = -1.18

RMS Wholesale Price Error = 1.26

Mean Actual Wholesale Price = 28.5

[1]The small difference between actual supply and actual demand represents field sales that have been omitted from demand.

4. Simulation of Policy Alternatives with the Econometric Model

With long lags from price changes to exploration, development and production changes, it might be expected that very little additional supply would be forthcoming in the next five years from increased field prices. Given "roll in" pricing in wholesale markets, field price increases would be passed through very gradually as wholesale price increases. As a result, there might be only limited reductions in demand as a result of the price increases, as well. These possibilities can be investigated by completing several simulations with the model

using alternative policies (in so far as these policies are reflected in alternative field prices), where the model has been set up to roughly approximate the conditions likely to be prevalent in the late 1970's.

The "gas economy" of the last half of the 1970's can be described in any number of ways, varying from quite expansive (due to shifts of energy demands to natural gas) to quite restrictive (due to reduced prices for alternative fuels as new coal-using technology is developed and vastly increased supplies of oil resources become available). The expansive view, when introduced into the econometric model, would result in large increases of demands, while the more restrictive expectations would have quite the opposite effect. When these conditions are replicated in the model, by introduction of appropriate values of exogenous variables, the size of the shortage becomes either larger or smaller. The approach taken here is to not choose an extreme set of values of the exogenous variables to be inserted into the model; rather, we choose a set of values that follows from "median" conditions likely to prevail in energy markets in the near future.

The important exogenous determinants of demands for gas include state-by-state value added in manufacturing, population level, income, and capital equipment additions. It is forecast that value added, income per capita, and capital additions will grow at 4.2 percent per annum (based on the Data Resources Quarterly Econometric Model forecast for the period 1972-1980). These rates of growth are in terms of constant dollars; we have chosen a "median" expected rate of growth of prices close to 3.5 percent per annum (based on both the Thurow-Ripley Long Term Econometric Model of Data Resources and the DRI Quarterly Econometric Model). Thus, value added and capacity

grow at 7.7 percent in current dollar terms. Population growth is much more modest; it is assumed that the rate of growth will be limited to 1.1 percent per annum for the rest of the decade (in keeping with the assumptions used in the economy-wide models for generating the rates of growth of value added and capacity).

Other exogenous variables that are determinants of the share of total energy markets that will be realized by natural gas are: (1) wholesale prices of alternative fuels in residential and commercial consumption, and (2) wholesale prices of alternative fuels for industrial use. Both are expected to increase at zero percent per annum in real terms and 3.5 percent per annum in current dollar terms. These are the forecasts in the National Petroleum Council's United States Energy Outlook and are the mid-points in a wide range of alternative simulations of production and demand conditions in petroleum and other fossil fuel markets.

Exogenous determinants of supply of reserves and production include the field price for crude oil in the producing regions, and the average drilling costs for oil and gas together. It is expected that oil prices will increase at no more than the rate of change of the price level (3.5 percent per annum); this too is based on the National Petroleum Council's United States Energy Outlook (pp. 40 *et seq.*). Average drilling costs are expected to increase at 5.75 percent per annum, in keeping with the trend of cost increases over the 1960's and early 1970's.

These values of the exogenous variables, together with assumed percentage increases of gas prices on new field contracts, can be inserted into the econometric model to produce simulated values of additions to reserves

and production by field region. Also, the results of simulation include demands for new production and for total production, and average wholesale prices for different classes of consumers in each of six wholesale markets. Each of the alternative regulatory policies implies a different series of field prices; separate simulations for each price series can be described and then compared with those for other policies.

4.1 Deregulation of Wellhead Prices

A large number of alternative proposals have been made under the rubric of "deregulation of field prices." These have included complete and instantaneous deregulation on the one hand, and a slightly higher rate of increase of F.P.C.-controlled prices on the other hand. But the central proposal is probably to allow new contract prices to seek their own levels, subject to a national ceiling on all new prices that would keep average wholesale prices from increasing by more than 50 percent over the subsequent five year period. This policy has been simulated as a price increase of 10 cents per Mcf on all new contracts in 1973 over a 25.2 cent per Mcf price level on new contracts in 1972. Prices would increase an additional one cent per year after 1973, as part of the market response to rising drilling and operating costs.

The impact of the price increases on new discoveries of reserves would not occur in 1973, but rather would be spread over the period 1974-1977. It is expected that 1973 new discoveries would be slightly more than 18 trillion cubic feet -- only 1 trillion cubic feet greater than the previous year (as shown in Table 3, for the econometric model simulation for

Table 3: Econometric Model Simulation Results for Policy Alternative "Deregulation"

Year	New Discoveries (Continental US, trillions of cu.ft.)	Total Additions to Reserves (Continental US, trillions of cu.ft.)	Total Reserves (Continental US, trillions of cu.ft.)	Supply of Production (Continental US, trillions of cu.ft.)	Demands for Production (Continental US, trillions of cu.ft.)	Excess Demand for Production (Continental US, trillions of cu.ft.)	New Contract Field Price (Continental US, cents per Mcf)	Average Wholesale Price (Continental US, cents per Mcf)
1970	11.5	22.0	230.8	19.4	21.4	2.0	20.7	29.6
1971	15.1	26.0	237.2	20.2	22.8	2.6	24.0	30.1
1972	17.5	28.4	245.0	21.3	24.2	2.9	25.2	30.7
1973	18.7	31.4	253.6	23.5	25.3	1.7	35.4	32.8
1974	23.2	35.7	265.1	25.0	26.1	1.1	36.6	34.5
1975	24.9	37.6	277.2	26.3	26.9	0.6	37.6	35.9
1976	25.9	38.8	289.5	27.5	27.7	0.2	38.7	37.3
1977	26.7	39.7	301.8	28.5	28.4	-0.1	39.7	38.6
1978	27.4	40.6	314.1	29.4	29.1	-0.3	40.7	39.9
1979	28.0	41.5	326.5	30.3	29.9	-0.4	41.7	41.1
1980	28.7	42.3	338.9	31.1	30.8	-0.3	42.7	42.4

"Deregulation"). But, by 1976, new discoveries would increase to the level of 26 trillion cubic feet and by 1979 would be 28 trillion cubic feet. Total additions to reserves (including new discoveries, extensions and revisions) would track new discoveries rather closely. A major part of the impact of price increases would be felt within four years, as an increase in annual additions 10 trillion cubic feet greater than previously experienced. The full impact would not be felt, however, until 1980, when total additions had leveled off at 42 trillion cubic feet, an amount approximately 14 trillion cubic feet greater than the 28 trillion realized before the 10 cent price increase.

Production out of reserves can be expected to increase for two reasons. First, the new contract field price increases of 10 cents or more per Mcf would make it more profitable to increase the level of development of existing reserves. Second, the additions to total new reserves induced by price increases provide more "reserve base" for more production. As a result, the supply of production would be expected to increase from 21 trillion cubic feet in 1972 to 31 trillion cubic feet by 1980. The combination of the larger reserve base and more production will keep the reserve-production ratio between 10/1 and 11/1 -- price increases provide additional incentives to take out a larger proportion of reserves, while also providing additional reserves, so that the two effects cancel out in the reserve-production ratio.

The demand side of gas markets experiences attrition as a result of the pass-through as the higher new contract field prices are passed along to the wholesale level. The wholesale prices do not increase very rapidly.

Because of the large number of old contracts still outstanding at the end of the 1980's, the average wholesale price at that point in time barely reaches the new contract field price level. But these prices rise on average from the 30 cent level in the early 1970's to 42 cents by 1980, and the increases have some effect on demands. The demands for production by residential, commercial, and industrial users throughout the country rise from 22 trillion cubic feet in the early 1970's to 31 trillion cubic feet by 1980, even with price increases, because of increased investment, consumer incomes, and population. In the absence of the field and wholesale price increases, demands would have increased from 22 trillion cubic feet to 40 trillion cubic feet.[1] Therefore, as a result of approximately 50 percent increase in wholesale prices spread over a 10 year period, total demands for production are decreased by 25 percent (from 40 to slightly more than 30 trillion cubic feet by 1980), and additions to demands are decreased by 50 percent (from 20 trillion to 10 trillion cubic feet).

The results of this policy of "partial deregulation" are to raise prices and greatly reduce the magnitude of the gas shortage. Price increases, while substantial, eliminate the production shortage after five years, so that by 1977, the supply of production and the demand for production are both approximately 28 trillion cubic feet at a reserve-production ratio close to 11/1. In subsequent years, supplies again match demands rather closely, but the reserve-production ratio does not increase. The production shortage is ameliorated, but the reserves margin over production remains low throughout the 1970's.

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[1]This estimate has been made by simulating with the same values of exogenous variables but with zero field price increase after 1973.

It might be asked whether the market clearing in these simulation results is highly sensitive to the choice of particular values of the exogenous variables. This would not seem to be the case. Simulations were also carried out with "high" and "low" sets of values of the exogenous variables; the "high" values included real rates of growth of value added, income, and plant and equipment outlay of 4.4 percent per annum, of population of 1.3 percent per annum, and real price increases for alternative fuels of 1.3 percent (residential and commercial use) and 3.0 percent (industrial use). These additions were matched by oil field price increases of 4 percent per annum in real terms. The rate of inflation was maintained at 3.5 percent per year. The result would be expected to increase demands for gas substantially -- but also to increase supplies of both oil and gas (particularly associated gas reserves). The simulation with "high" values of the exogenous variables shows, in fact, additions to reserves 5 trillion cubic feet greater than the 42 trillion cubic feet for 1980 in the "median" case in Table 3. Production out of reserves is expected to exceed 32 trillion cubic feet, because of the additional volumes of new discoveries available. Demands for reserves in this "high" value case exceed 34 trillion cubic feet so that there is a shortage of approximately 1.3 trillion cubic feet in production in 1980.

"Low" values of the exogenous variables would be quite similar to the "median" values, except that value added and per capita incomes would increase one percent less per annum, and both field and wholesale prices of

alternative fuels would decline slightly.[1] In this simulation, the low values of field prices for oil dampen incentives for exploration of (associated) gas, so that annual new reserves by 1980 are approximately 0.5 trillion cubic feet less than shown in Table 3. The supply of production out of reserves is also 0.5 trillion cubic feet less, but demands for production are dampened from 31 trillion cubic feet in 1980 to 28 trillion cubic feet, so that more than enough production is supplied to meet demands over the period 1976-1980. Reserve-production ratios in this case are allowed to go up slightly from the 11/1 level. Altogether, the size of the shortage ranges from one trillion cubic feet in the "high" value case to -2 trillion cubic feet in the "low" value case.

The impression is that "deregulation" that results in field prices in the 35 to 42 cent range over the rest of the decade would clear production markets of excess demand. There is some chance that there would still be a shortage as large as 8 percent, if "high" values of exogenous variables increased demands for gas more than reserves and production. But the most likely values of exogenous variables, and even the "low" values, would clear production markets, with low reserve backing the only indicator of a gas shortage.[2]

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[1]The expected rates of decline are 4.6 percent for field prices of alternate fuels, 0.2 percent for wholesale prices of alternate fuels for residential and commercial use, and 0.3 percent for wholesale prices of alternate fuels for industrial use. These are in keeping with the National Petroleum Council's United States Energy Outlook (December 1972), pp. 40 *et seq*. It is assumed that prices would increase at 3.5 percent per annum in money terms, in the "low" value case as well as the "median" and "high" value cases for simulation.

[2]In fact, it is difficult to say whether a reserve-production ratio of 10 or 11 represents a reserve shortage. Although there may be demands for higher ratios at these prices, they cannot easily be registered (and prices allowed to rise to meet these demands).

4.2 Strict "Cost of Service" Regulation of Field Prices

One criticism of the regulatory "status quo" is that prices have been allowed to creep up at the rate of 1.5 cents per annum on new contracts, when there has been little "cost justification" for this to occur. It is argued that the Federal Power Commission should follow traditional procedures for setting prices -- that is, full reviews of the cost of providing gas should be undertaken and prices should be limited to these costs. It is expected that under this regimen, price increases under new contracts would be limited to one cent per annum. This would result in average wholesale prices limited to the 30 to 36 cent range over the 1970's (as shown in Table 4).

The effects of such limited price increases on reserve and production supply would be substantial. New discoveries would increase by less than one trillion cubic feet per year for the remainder of this decade, and total additions to reserves would be limited to 30 to 35 trillion cubic feet per year. The supply of production out of reserves would range from 23 trillion cubic feet in 1974 to slightly less than 28 trillion cubic feet in 1980. Altogether, additions to reserves are approximately 3 trillion cubic feet less per year than under the "deregulation" policy shown in Table 3.

The demand for production would be much greater when prices are held within this range. Total demand for new production increases by 1.5 to 1.8 trillion cubic feet per annum (as shown in Table 4). Total new demands by 1980 are expected to be more than 36 trillion cubic feet, 5 trillion cubic feet greater than under price increases associated with "deregulation."

Table 4: Econometric Model Simulation for Policy Alternative "Cost of Service Regulation"

Year	New Discoveries (Continental US, trillions of cu.ft.)	Total Additions to Reserves (Continental US, trillions of cu.ft.)	Total Reserves (Continental US, trillions of cu.ft.)	Supply of Production (Continental US, trillions of cu.ft.)	Demands for Production (Continental US, trillions of cu.ft.)	Excess Demand for Production (Continental US, trillions of cu.ft.)	New Contract Field Price (Continental US, cents per Mcf)	Average Wholesale Price (Continental US, cents per Mcf)
1970	11.5	22.0	230.8	19.4	21.4	1.9	20.7	29.6
1971	15.1	26.0	237.2	20.2	22.8	2.6	24.0	30.1
1972	17.5	28.4	245.0	21.3	24.2	2.9	25.2	30.7
1973	18.7	29.8	253.2	22.3	25.6	3.3	26.3	31.3
1974	19.5	30.7	261.6	23.2	27.0	3.8	27.3	31.9
1975	20.0	31.5	270.0	24.0	28.4	4.4	28.4	32.6
1976	20.6	32.2	278.4	24.8	29.9	5.1	29.4	33.3
1977	21.1	32.9	286.8	25.6	31.4	5.8	30.4	34.0
1978	21.7	33.7	295.3	26.4	33.1	6.7	31.4	34.8
1979	22.2	34.4	303.9	27.1	34.8	7.7	32.5	35.5
1980	22.8	35.2	312.6	27.9	36.6	8.8	33.5	36.4

Excess demands persist over the remainder of the decade. Indeed, the gap between supply and demand for production increases as time passes, from approximately 4 trillion cubic feet in 1974 to 9 trillion cubic feet by 1980. The impact of this "cost of service regulation" policy is to exacerbate the excess demands that already exist, so that the shortage would be more than 30 percent of the supply of production by 1980.

These conditions can be expected whether the "median" values, the "high" values, or the "low" values of the exogenous variables are used in the simulations. When "high" values are used, the size of excess demand exceeds 10 trillion cubic feet per year, because additions to demands from market growth and price incentives exceed additions to (associated) supply from oil price increases. When "low" values are used, the excess demand is limited to 6.8 trillion cubic feet per year. But, in all three cases, the shortage increases over the remainder of the decade, and is equal to 20 percent or more of the available supply of production out of reserves.

4.3 Maintenance of the Regulatory "Status Quo"

Continuation of regulation is envisioned as a maintenance of the 1970-1971 policy of allowing price increases on new contracts of 2 to 4 cents per Mcf each year. The cases on field pricing brought before the Commission for the rest of the decade would be decided on any number of cost or other bases, but the result would be a price series for new commitments of reserves as shown in Table 5 -- with annual increments of approximately 3 cents per Mcf per year leading to prices in 1980 of more than 50 cents per Mcf. Such price changes would not be easy to put into effect -- each

Table 5: Econometric Model Simulation Results for Policy Alternative "Regulatory Status Quo"

Year	New Discoveries (Continental US, trillions of cu.ft.)	Total Additions to Reserves (Continental US, trillions of cu.ft.)	Total Reserves (Continental US, trillions of cu.ft.)	Supply of Production (Continental US, trillions of cu.ft.)	Demands for Production (Continental US, trillions of cu.ft.)	Excess Demand for Production (Continental US, trillions of cu.ft.)	New Contract Field Price (Continental US, cents per Mcf)	Average Wholesale Price (Continental US, cents per Mcf)
1970	11.5	22.0	230.8	19.4	21.4	1.9	20.8	29.6
1971	15.1	26.0	237.2	20.2	22.8	2.6	24.1	30.1
1972	17.5	28.8	245.1	21.6	24.1	2.5	27.3	31.1
1973	19.5	31.2	254.0	23.0	25.3	2.3	30.5	32.2
1974	21.3	33.4	263.9	24.4	26.4	2.0	33.6	33.5
1975	23.0	35.6	274.7	25.8	27.3	1.6	36.6	35.0
1976	24.8	37.9	286.4	27.2	28.2	1.0	39.7	36.7
1977	26.7	40.2	299.0	28.6	28.8	0.3	42.8	38.5
1978	28.7	42.6	312.7	30.0	29.4	-0.6	45.8	40.5
1979	30.8	45.1	327.5	31.4	29.8	-1.6	48.9	42.7
1980	32.9	47.6	343.5	32.9	30.2	-2.7	51.9	44.9

requiring multiple applications for certification of new contracts under conditions different from the previous year's certification, each requiring some conceivable set of estimates of the (increased) cost of providing the new contract production at successively higher prices. But these increases, if allowed by a commission trying to reduce the shortage, would raise average wholesale prices from 30 cents to 45 cents by 1980, and would have a perceptible effect on both supplies of reserves and production, and demands for production.

Supplies of reserves are expected to increase at a faster rate under these conditions than under "deregulation." The increments of new discoveries and total additions to reserves are shown in Table 5; they exceed those for Table 3 by 4 to 5 trillion cubic feet at the end of the decade. The supply of production out of reserves is almost 2 trillion cubic feet greater as a consequence. The combination of successive 3 cent increments leading to a higher final price, and of near-certainty of the occurrence of these increments, lead to substantial additions to both reserves and production.

Demands for production, on the other hand, are approximately the same as under "deregulation." The successive increments of new contract field price increases pass through as average wholesale price increases only gradually. Even though the new contract field price is approximately 9 cents per Mcf higher in 1980 under the "regulatory status quo" than under "deregulation," average wholesale prices are close to 45 cents under regulation and 43 cents under deregulation. As a result, demand for production

increases from 21 trillion cubic feet in 1970 to 30 trillion cubic feet in 1980, the same levels and rates of increase as under "deregulation."

The supply-demand balance is achieved under the "status quo" in 1977. In subsequent years, the total supply of production would be from 1 to 3 trillion cubic feet greater than the demand, so that -- rather than producing excess supply -- further increments would be added to reserves so as to raise the reserve-production ratio in the early 1980's. This occurs with approximately the same timing as under "deregulation," but the increments of supply over and above the demands for production are larger under the "status quo" than under "deregulation" in 1979-1980.

The use of "high" or "low" values of exogenous variables again does not affect the outcome of this policy. Markets are cleared of the shortage under the "status quo" in 1975 using "low" values of exogenous variables, and in 1978 using "high" values of exogenous variables. The increment by which supply of production exceeds demands in 1980 equals 1.7 trillion cubic feet in the "low" simulation and 1.2 trillion cubic feet in the "high" simulation. In all of the simulations of continued regulation, policies of the Federal Power Commission that allow 3 cent per annum price increases eliminate the shortage of production two to four years after being put into effect.

4.4 Comparisons of Alternative Policies

The policy choices facing the government and the natural gas industry are numerous and complex, involving combinations of changes by the Legislature and within the independent regulatory commission. But, when policies

are "polarized" and treated as price level changes, the effects of a wide range of alternatives on the magnitude of the natural gas shortage are not remarkably different. The government can "deregulate" by legislative act and reduce the production shortage to negligible size within four to five years. The Federal Power Commission can achieve almost the same result by stretching the standards for justifying price increases so as to allow increases of 3 cents per annum. A combination of these two policies would probably have similar effects -- legislative changes that specifically allow the Federal Power Commission to depart from "cost of service" regulation with 3 cent annual price increases would reduce the gas shortage. The pipelines would not support liquid or synthetic gas investments as solutions to the shortage -- at least not if the costs of these investments were greater than 45 cents per Mcf. There is little basis to choose between the two alternatives in terms of eliminating the shortage of gas production, other than that "deregulation" achieves the shortage elimination with less wholesale price increase over the decade.

Both of these alternatives are preferable to strict "cost of service" regulation. Regulatory stringency is expected to increase the size of the shortage from approximately 2 trillion cubic feet of production per year to 9 trillion cubic feet by the end of the decade (as in Table 4). Synthetic or liquefied gas at more than 45 cents per Mcf would be justifiable as investments under regulation, because they would alemiorate the shortage. Given strong political and economic reasons for reducing the shortage, this way of doing so is the most prolonged and the most costly.

APPENDIX

List of Variables and Data Sources

The variables used to estimate the model, including sources of data, are listed below. The list is divided into field market variables and wholesale market variables. No production or price data is available for Louisiana Offshore.

Wells

WXT: Total exploratory wells, successful or otherwise.
CWXT: cumulative value of exploratory wells (WXT), from 1963 to t.
REVD: index of average deflated revenue from gas and oil for each production district.
ATCD: average drilling cost per well of exploratory and development wells, from Joint Association Survey, (AGA/API/CPA).
RISKV: index of the variance in size of discoveries over time by production district. This is a pure cross-section variable which doesn't change in time
AFX: average depth of an exploratory well (averaged over total wells)

Reserves: all data from AGA/API/CPA Reserves of Crude Oil. Only available in disaggregated (i.e., associated-dissolved, non-associated, by production district) form from 1966 except for year-end reserves (YN, YA, US) which we have from 1965. Data is given in millions of cubic feet.
SIZEDN: average size of non-associated discoveries, by production district (averaged over total wells, dry and successful).
SIZEDA: average size of associated discoveries, by production district (averaged over total wells, dry and successful).
DDA: Dummy variable for Louisiana south.
DDB: Dummy variable for the Permian producing region.
DDC: Dummy variable for Kansas, Oklahoma, TRRC Districts 1, 2, 3, 4, and 10.
DDD: Dummy variable for Louisiana north, Mississippi, New Mexico north, Pennsylvania, West Virginia-Kentucky, Wyoming, TRRC6 and TRRC9.

YN: Year end non-associated reserves. Reserves as defined by the AGA.
YA: Year end associated-dissolved reserves. See YN.
YT: Year end total gas reserves. YT = YN + YA.
YO: Year end oil reserves.
US: Year end reserves in underground storage other than in their original locations.
XN: Extensions of non-associated gas. Includes any newly proved reserves already established in pools and fields.
XA: Extensions of associated-dissolved gas. See XN.
RN: Revisions of non-associated gas. Includes any proved decreases in size of proved reserves discovered by drilling of extension or development wells or changes (+ or -) resulting from better engineering estimates of economically recoverable reserves in established pools.
RA: Revisions of associated-dissolved gas. See RN.
FN: New field discoveries of non-associated gas (discovered by new field wildcats).
FA: New field discoveries of associated-dissolved gas. See FN.
PN: New pool discoveries of non-associated gas.
PA: New pool discoveries of associated-dissolved gas.
DN: = FN + PN. Total new discoveries, non-associated.
DA: = FA + PA. Total new discoveries, associated-dissolved gas.

Production: All data is from AGA/API/CPA, Reserves of Crude Oil, and is available in disaggregated form from 1965 for gas (and 1940 for oil). In 10^6 cubic feet and 10^3 barrels.
QN: Production of non-associated gas, i.e., net production.
QA: Production of associated-dissolved gas, net production.
QO: Production of oil.
QSRI: Sales for resale which will end up as industrial sales are determined by multiplying total sales for resale (from F.P.C. Form 2 Reports) by the fraction of total industrial natural gas consumption (from U.S. Bureau of Mines, Minerals Yearbook).
QSRCR: The difference btween total sales for resale and industrial sales for resale. (See QSRI for sources.)
QINTRA: The difference between total consumption of natural gas by state and total mainline sales plus sales for resale plus field sales in that state. Figures on total consumption by state are taken from Bureau of Mines Minerals Yearbook, as are total field sales. Mainline sales and sales for resale figures are from FPC Form 2 reports.
QM: Total mainline industrial sales volume by interstate pipeline companies by state and year (1955-1970) in Mcf, from FPC Form 2 Reports.
QSR: Total sales for resale volume by class A and B interstate pipeline companies, by state and year (1956-1970) in Mcf, from FPC Form 2 report
L: Losses and waste, by states (Texas, Louisiana and New Mexico undivided). From API Petroleum Yearbook.

Prices:

PG: New contract price of interstate sales of gas at the wellhead, from Table F, FPC, Sales of Natural Gas, for 1952-1971, in ¢/Mcf. (Compiled Foster Associates, Inc.)

PO: Wellhead price of oil in $/barrel for 1954-1971, from Bureau of Mines, Minerals Yearbook.

POIL: Average price per Mcf-energy-equivalent of fuel oil paid by electric power companies by state, from Edison Electric Institute, Statistical Annual of the Electric Utility Industry.

PALT: Price index of alternate fuels. Weighted average (over kilowatt-hours generated) of prices of fuel oil and coal consumed by electric utility industry in generating electric power, by state and year from 1962-1969. (See POIL for source.)

PM: Price of mainline industrial sales made on a firm basis, by state and year from 1952-1970. Data taken from FPC Form 2 Reports, in $/Mcf.

PSR: Price of sales for resale in $/Mcf from 1956-1970, by state and year. Data taken from FPC Form 2 Reports.

PRATIO: = PG/PO.

M: The distance from the center of a producing region to the population center of the consumption region.

V: The sum of the squares of pipeline diameters entering the state, by state.

VAM: Value added in manufacturing in millions of dollars by state and year, from 1958-1969 (interpolated for 1968). Data taken from U.S. Department of Commerce, Bureau of the Census, Annual Survey of Manufacturers.

K: New capital expenditures in millions of dollars; see VAM for source.

VCC: Value of construction contracts by states in which work was done, from 1956-1970, in millions of dollars. Data taken from Statistical Abstract of the U.S. and from F.W. Dodge Corporation, Dodge Construction Contract Statistics Service.

Y: Personal income by state, from 1956-1969, in millions of dollars. Data taken from U.S. Bureau of Economic Analysis, Survey of Current Business.

N: Population by state and year, from 1955-1970, in millions. Data taken from U.S. Department of Commerce, Bureau of the Census, Current Population Reports.

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