THE ECONOMICS OF THE NATURAL GAS SHORTAGE (1960-1980)

Paul W. MacAvoy
Robert S. Pindyck

Report # MIT-EL 74-011

September, 1974

THE ECONOMICS OF THE NATURAL GAS SHORTAGE (1960-1980)

by

Paul W. MacAvoy and Robert S. Pindyck

Massachusetts Institute of Technology

Energy Laboratory Report no.
MIT-EL 74-011

September, 1974

TABLE OF CONTENTS

PREFACE

An appraisal of the natural gas shortage requires both a detailed description of political and technical institutions, and an economic analysis of the evolving performance of this industry. Not much can be said without a description of the legal controls on producing gas in the South for delivery to consumers in the North, or without an economic analysis of price and quantity relationships on both the production and demand sides of gas markets. There also has to be some indication of the present size of the shortage, of the means by which the industry would respond to policies to reduce the shortage, and how much time this response would take.

The approach here divides the institutional and analytical materials into two parts. First, the political and institutional frame of reference is described and the present-day natural gas shortage is estimated in Chapter 1; and forecasts are made of the effects on this shortage of various alternative regulatory policies in Chapter 2. Second, a large-scale econometric policy model of natural gas markets- both field markets and wholesale distribution markets---is presented in Chapters 3,4 and 5 in some detail. Thus the model is described in Chapters 3-5 after it is used for evaluating alternative policies in Chapter 2. This is done so that non-econometricians can deal, with least obfuscation and delay, with the results from the policy analyses, leaving it to the more technically oriented analyst to check these results against the model and simulation descriptions in Chapters 3-5. However, frequent references are provided in Chapter 2 to the technical description in subsequent chapters, so that documentation or analysis can be obtained where needed even by the non-econometrician.

The plan of the book, then, is as follows:(1) introduction to the natural gas shortage and the technical-regulatory frames of reference for explaining the present extent of the shortage. This is followed by (2) an analysis of alternative policies for dealing with the shortage, using the econometric policy model described in technical detail in Chapters 3, 4, and 5. For those seeking to understand the general nature of the present policy problems in the natural gas industry, Chapters 1 and 2 should suffice; for those interested in the development of an econometric model designed specifically to assess the efficiency of alternative regulatory policies in dealing with shortages, Chapter 3, 4, and 5 should be of particular interest.

Acknowledgements

This study reports on the results of a National Science Foundation project to develop an econometric policy model of natural gas, under grant no. GI-34936. The first phase of the project was described in Sloan School of Management working paper no. 635-72 (December, 1972), and the second phase was reported in "Alternative Regulatory Policies for Dealing with the Natural Gas shortage" by P.W. MacAvoy and R.S. Pindyck in the Bell Journal of Economics and Management Science, vol. 4, no. 2, Autumn, 1973. A project of the scope of the gas policy model has to be undertaken as a group effort. We received the substantive support and assistance of a number of colleagues here at M.I.T., and without this extended help this project would not have been completed. The assistance of Krishna Challa, doctoral candidate in the Sloan School, was extensive in the construction of the model of reserves; as noted in Chapter 3, the formulation of structural equations for reserves is essentially that in Krishna Challa's doctoral dissertation entitled "Investment and Returns in Exploration and the Impact on the Supply of Oil and Natural Gas Reserves". Similarly, Ira Gershkoff and Philip Sussman played substantial roles in the formulation of parts of the model--Gershkoff in the price markup equations and input-output table, Sussman in the model for offshore reserves and production. Sussman's work, now part of the model, is described in "Supply and Production of Offshore Gas Under Alternative Leasing Policies", an M.S. dissertation at the Sloan School of M.I.T. (1974). Robert Brooks and Marti Subrahmanyam, M.I.T. doctoral students, played major roles in the construction of natural gas demand equations, and Bruce Stangle, also a doctoral student, helped us in the development of the oil demand equations. Birgul Erengil, an M.S. student at Sloan, provided assistance in the documentation of our final results. Finally, Kevin Lloyd, also an M.S. student, took on the task of managing all of the computer operations involved in constructing the model, prepared and conducted most of the simulation exercises, and assisted in the estimation of most parts of the model. We are indebted to those cooperative and productive colleagues.

The computational work was performed at the Computer Research Center of the National Bureau of Economic Research in Cambridge, Massachusetts, and relied on the TROLL system for the estimation and simulation of the model. Also, the data base was constructed and maintained at the NBER Computer Research Center. The considerable assistance that we received in the use of TROLL from Mark Eisner and Walt Maling of the NBER, as well as others on the staff of the Computer Research Center, was invaluable in the construction of the model, and is extremely appreciated.

This project has been one of many undertaken at the M.I.T. Energy Laboratory. We wish to express our appreciation to our colleagues in the Energy Laboratory, particularly Morris A. Adelman, Gordon Kaufman, Jerry Hausman, Paul Joskow and Martin Baughman for comments on earlier drafts and help in reformulation of the model in the final phase. Substantial assistance was provided by Edward Erickson, Dale Jorgenson, Edward A. Hudson, Daniel Khazzoom, Edward Kitch, Robert Spann, and Lester Taylor as a result of their reviews of the preliminary draft of this manuscript. Finally, a large number of readers of the earlier version of the model--as well as users of the model--provided comments and criticisms that added to our efforts in reformulating the econometric analysis. This legion of critics, mercifully granted anonymity, made the work towards the final version worthwhile.

Cambridge, Massachusetts
September, 1974

CHAPTER 1:

GOVERNMENT REGULATION AND INDUSTRY PERFORMANCE, 1960 - 1974

1.0 Introduction

The natural gas industry in the United States has experienced substantial shortages in the last few years. Rather than hour-long queues, as at gasoline stations in early 1974, the natural gas shortage of the 1970's has resulted in partial or total elimination of service for groups of consumers, both residential and industrial, that demand gas rather than other fuels. Service has been terminated for interruptible buyers--those taking gas only part-time or off-peak--and new potential full-time consumers have not been allowed to connect to delivery systems. At many locations, industrial and commercial consumers have been told to replace gas with oil at least on a part-time basis. The sum total of these unfilled demands has been fairly extensive. The Federal Power Commission found that interstate gas distributors were 3.7 percent short of meeting consumption demands of communities and industries in 1971 and that they are expected to be 10 percent short of demands in 1974.[1]

There appears to be small prospect for amelioration of shortage conditions in the near future. Unless there are unexpected discoveries, or unless FPC regulation changes significantly, excess demand is expected to grow to more than one-quarter of total demands [2] This is not only the prediction of econometric forecasts. Indeed. the FPC staff of gas experts

---

[1] cf. National Gas Supply and Demand, 1971-1990 (FPC Bureau of Natural Gas, Washington D.C., February, 1972).

[2] This forecast is the result of use of an econometric policy model to simulate continuation of present geological and regulatory constraints over the period 1975-1980. The model is described in Chapters 3-5, and the simulations outlined in Chapter 2, below.

forecasts that, assuming continuation of present day regulatory conditions, the shortage will grow to be as large as 20 percent of demands by 1980.[3] Those that are now being told to curtail consumption or to switch to other fuels are not likely to be told anything different unless public policies change.

Consumers in some regions of the country have fared worse than those in other regions in obtaining the gas they demand. So far, buyers in the North Central, the Northeast and the West--in that order--have incurred most of the shortage. New residential buyers and new as well as some old industrial buyers in those regions continue to be kept off distribution systems. By the late 1970's, shortages in the North Central region could exceed one-half of demands. If this occurs, then industrial and commercial establishments will face 100 percent elimination of supply, in order that there would still be enough gas to meet the "old household" consumption draughts on local utilities. In other regions, industry may not be cut off entirely, but substantial industrial buyers seeking to expand their uses of gas would face curtailment at most locations. Some of these buyers should be able to obtain more supply in the South, outside of regulation and the shortage by relocating their activities.[4] If they were to relocate in significant numbers, there would be important changes in regional industrial development. Industrial growth in the energy-related industries of the upper Midwest would be reduced relative to the rest of the country.

---

[3] cf. <u>National Gas Supply and Demand</u>, <u>op. cit.</u>; this forecast calls for almost as much shortage as the gas econometric forecast; presumably it is based on continuation of present price regulation (although this is not explicit).

[4] These statements are once again predictions from the econometric model described in detail in Chapters 3-5. The forecasts for 1975-1980 shortage conditions are developed at length in the next chapter.

These conditions should elicit questions from many consumers in the next few years. As service is curtailed, they might well ask, where the shortage came from. In particular, they should know how long it will last under continuation of present conditions in gas markets and if the shortage can be reduced at an earlier date by policy changes of companies and governments.

It is important to know first where the shortage came from," so that policies specific to type of consumer, location and time period can be formulated to eliminate the shortage-creating conditions. The next section of this chapter (1.1) specifies the details of the production process in gas fields necessary for an understanding of the shortage situation. In Section 1.2, there is a lengthy description of gas field price regulation by the Federal Power Commission. Regulation has become an important precondition of production, and certain aspects of regulation can be seen to have caused the development of the shortage. The third section below (1.3) describes the behavior of field markets under present regulatory controls as compared to "no control" conditions. The conclusions here, showing the effects of controls, give credit to the regulators for the shortage. Subsequently, Chapter 2 attempts to answer the question, "how long will there be an extensive shortage" under present conditions.[5] Also, studies are presented of the effects from alternative governmental policies that show that extensive change in the present method of control, and present price levels, can have substantial ameliorative effects on the shortage.

1.1 Production and Distribution of Natural Gas

The field markets for natural gas center around transactions in which petroleum companies dedicate newly-discovered <u>reserves</u> of natural gas for <u>production</u> into pipeline transmission lines. Major petroleum

[5]The forecasts are based on simulations with the econometric policy model described in Chapters 3-5.

companies, along with smaller independents, initiate activities by using seismic logging and the drilling of wells to "discover" new gas reserves, or to complete the "extension" or the "revision" of previously known reserves. They bring gas production to the surface where liquid by-products are removed. Then the pipeline companies take the gas in the field and deliver it to wholesale industrial users or to retail distributing companies, that in turn deliver it into individual households, commercial establishments or to retail industrial users. Ultimately, more than 45 percent of the natural gas production goes to residential and commercial consumers, while the rest is consumed as boiler fuel or process material in industry.[6]

Reserves, production, and the pattern of consumption depend on certain technical and economic conditions. The most important of these relationships, in terms of an "economic model," are sketched in the flow diagram below. Each of the boxes will be dealt with later in detail (since this is a simplified version of the flow diagram for the econometric model described in Chapters 3-5); but it is posited here that prices of oil and gas are critical policy variables, such as the leasing practices on government lands that determine production. Also, oil and gas prices are policy-related determinants (along with non-policy variables such as other fuel prices and consumer incomes) of residential or industrial

---

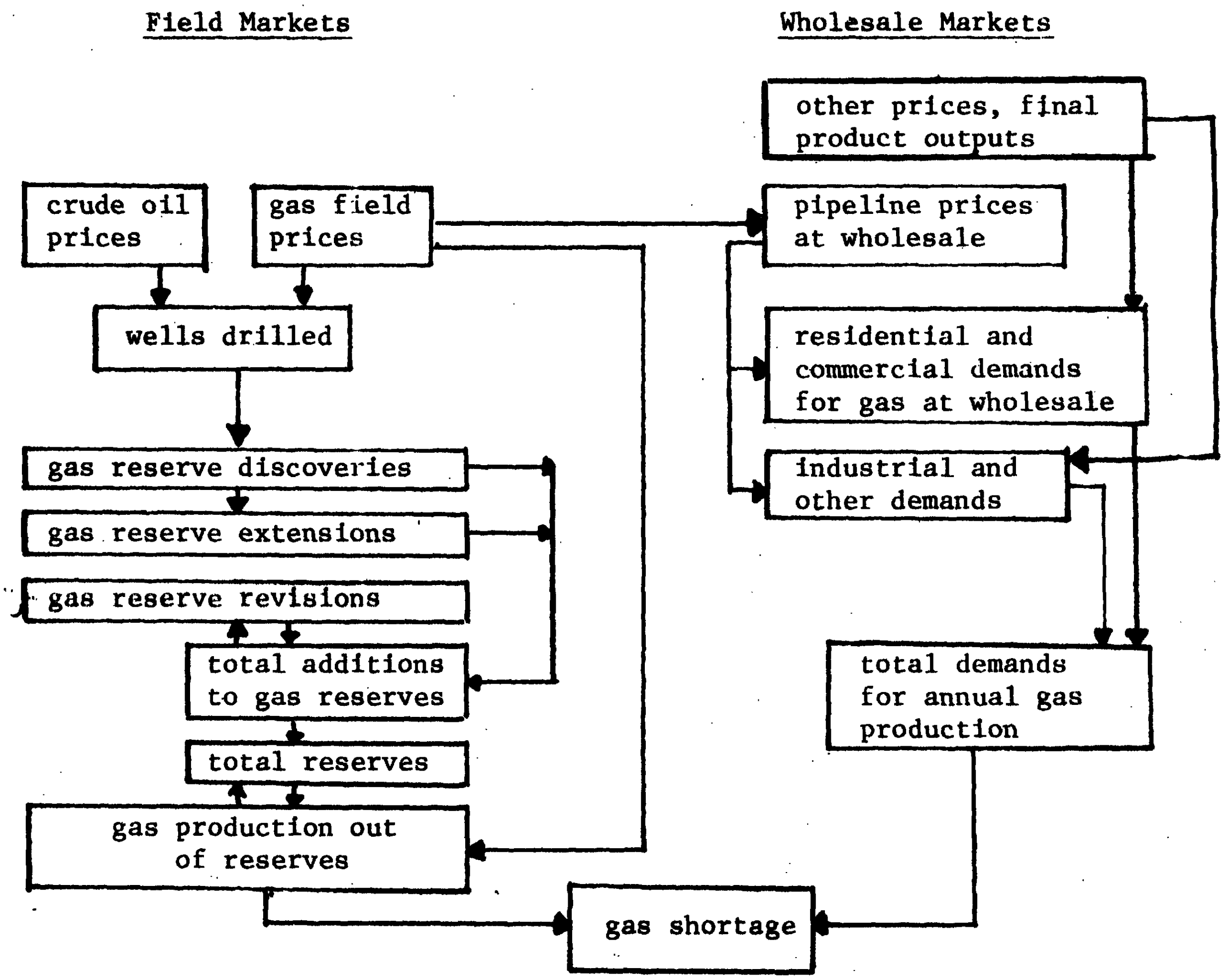
[6] The percentage of total consumption by residential and commercial buyers was 45 percent in 1962, and 43 percent in 1968: as the natural gas shortage appeared on the horizon, the amount of residential consumption declined. cf. Federal Power Commission, Statistics of Natural Gas Pipelines (annual); cf. also S. Breyer and P.W. MacAvoy, "The Natural Gas Shortage and Regulation of Natural Gas Producers," Harvard Law Review (vol. 86, no. 6, April 1973), pp. 977 et seq.).

demands for gas.[7]

1.1.1 Field Markets[8]

The gas reserves committed by the producing companies to pipelines are accumulated through a complex and time consuming process. The companies ascertain that there are inground deposits of (1) "associated" gas in newly discovered oil reservoirs and (2) "nonassociated" gas found in reservoirs not containing oil.

Figure 1.1 Simplified Diagram of the Econometric Model



[7] These are all statements of empirical relations, based on the equation relationships formulated in Chapter 3 and fitted in Chapter 4 below.

[8] This subsection, like the previous one, describes in straightforward terms the equation relationships in the econometric model of Chapters 3 to 5 below. The description is based on the direction of cause-effect relationships found below, and seeks to indicate extent by including coverage of only the important relationships with policy or with certain non-policy variables.

Companies claim such reserves as a result of new discoveries, or extensions or revisions of previous discoveries (where extensions result from stepping out beyond the limits of known field boundaries, and revisions are changes in estimates of reserves in place within known field boundaries).

After reserves are known to exist, the producers "dedicate" them in a contract calling for production over a five-to-twenty year period. In effect, the producers estimate the size of newly-found inground deposits and provide sufficient documentation to support contract commitments to pipelines for production over that period. Of course, reserves are never known for certain (as indicated by extensions and revisions each year), so that the contracts are in effect "futures" agreements or promises to deliver an uncertain volume of a commodity.

The process of adding to reserves begins long before commitments to pipelines. Years earlier, the producer undertakes geophysical exploratory work to show the existence of a potential inground hydrocarbon reservoir, after which he sinks wells into the reservoir to determine whether there is oil, gas, water, or whatever. The decision to conduct preliminary geophysical research and drill wells is essentially an investment decision under uncertainty; as the potential profitability of the investment increases, the number of wells drilled increases and total discoveries increase.[9] Profitability depends upon future prices and costs, which relate in a complicated but positive way to present prices and costs. Thus if present prices increase, there should be an increase in exploratory work; this

---

[9] In the econometric model, this process is described as being divided between decisions on "well-drilling" and "size of discovery" per successful well. Operating at the intensive margin implies increased drilling and reduced size of find per successful well. Operating at the extensive margin implies increased drilling and an increase in the size per successful well. Both together imply rising supply of reserves as prices increase.

would lead, in a year or two, to additional drilling activity and subsequently to the offering of additional reserves for sale to pipeline buyers. Of course prices are not the only determinant of reserves. There is a fixed stock of gas to be discovered in a region, and it is suspected that the larger and most profitable volumes are discovered and dedicated there first. Technical progress in drilling or production techniques could compensate for the limits in any area by pushing down costs of finding the smaller volumes; also, some areas may not yet have experienced the initial stages.[10] But over time, at fixed prices and costs, we should observe that the volume of discoveries declines per well drilled.[11]

The discovery of reserves is the first step in the production process. The second step is contractual dedication to the production of gas and its

---

[10]This again is dealt with explictly in the econometric model described in Chapters 3-5. The summary here does not take account of the relative importance of the variables (a) prices (b) technical progress (c) earlier discoveries in explaining additions to reserves. The equations in Chapter 4 provide this important detail.

[11]At the present time, the limits on total reserves do appear to be constraining. We are not "out" of discoverable reserves in the United States. The sum total of past production and of present discovered reserves, as of 1970, totaled 648 trillion cubic feet, less than 40 percent of the amount of ultimate discoverable reserves expected in most forecasts. The amount remaining to be discovered has been estimated as 851 trillion cubic feet (by the National Petroleum Council and by the Colorado School of Mines' Potential Gas Committee), and as 2,100 trillion cubic feet (by the U.S. Geological Survey). (National Petroleum Council, U.S. Energy Outlook: Oil and Gas Availability, U.S. Dept. of the Interior, Tables 291 and 292 on page 367; Potential Gas Agency, Minerals Resources Institute, Colorado School of Mines, Potential Supply of Natural Gas in the United States, October 1971 (the latest report, issued in December 1973, gives 1,146 trillion cubic feet; U.S. Geological Survey, Circular 650, "U.S. Mineral Resources," states that the range of estimates is between 1,178 and 6,600 trillion cubic feet.) Of course the amount actually found and put in the reserves category will depend on the level of exploratory activity, on costs of development, and on the prices offered by the pipeline buyers. These are the most important (technical and economic) limiting factors; the reserve estimates show enough additional reserve inventory to support at least two decades of production (at forecast rates exceeding 30 trillion cubic feet per annum).

movement in the pipelines to final consumers. The amount of production depends on a number of geological, engineering, and economic factors. Production cannot take place at rates greater than some fixed percent of reserves per annum, because of technical limits (sandstone in the reservoirs is not completely permeable so that the gas cannot move to the well faster) and because of economic costs (faster rates of depletion may reduce the economic value of any remaining reserves by "channeling" and sealing off parts of the reservoir from further production). But up to these limits, more production can take place at higher short-run costs. Thus, with a given reserve inventory, if prices are high enough to compensate for higher costs of further drilling investment, the production rate can be increased.[12]

Field markets for natural gas are, thus, similar to minerals or raw materials futures markets in which present deposits are dedicated for future production and refining. The important characteristics of these markets generally are that more reserves will be dedicated if the buyers offer higher prices, and that the lag adjustment process bringing forth additional reserves by higher prices is likely to be long. Also, production out of dedicated reserves is limited by technical or economic factors, but is likely to be greater, the larger the volume of reserves available and the higher the contract prices.

1.1.2. Wholesale Markets

The buyers of reserves at the wellhead are for the most part natural gas pipelines providing gas under long-term contract to industrial consumers and retail public utility companies. The amounts of their annual deliveries

---

[12]That is, in the econometric model below, technical and economic conditions determine production out of reserves, so that the level of production will be greater, the greater is the volume of reserves in place and the higher are prices in the contract commitment.

determine their demands for reserves to be dedicated at the wellhead. These annual deliveries in turn depend upon the prices they charge for gas at wholesale (paid by industrial consumers and retail public utilities to the pipelines), the prices for alternative fuels consumed by final buyers, and economy-wide factors such as population, incomes, industrial production, etc., that determine the overall size of energy markets.

Gas wholesale prices, in turn, depend upon field prices and delivery charges for transportation of the gas from the wellhead to the final consumer. The pipelines offer instantaneous deliveries of gas as it is burned by the final buyer: they charge a markup over their field purchase prices as part of the wholesale price for these services. Markups are determined by the historical average costs of transmission and by the transportation profit margins allowed under Federal Power Commission regulation (at least for the interstate pipelines).

Regulation of the wholesale prices, in fact, builds in significant lags of changes in final prices behind those in field prices. The Federal Power Commission has followed the policy of allowing wholesale prices equal to the markup plus the historical average field price paid for gas at the wellhead. This "rolled in" or average wellhead price changes slowly as a result of higher prices on new field contracts, because new contracts in any year make up only 5 to 15 percent of all contracts. The full impact of a change in new contract prices is realized only after it has been in effect for almost a decade (assuming 10 percent of deliveries in each year come from new contract dedications). This time lag between changes in wellhead and wholesale prices softens the impact on consumers of large increases in new prices in field markets. Also, average transmission costs change very slowly, as new construction costs or allowed returns on capital change slowly (at least as allowed by the FPC).[13] From 35 to 40 percent of the gas remains in the South Central region of the country where it is produced; approximately 19 percent moves to the Northeast, 20 percent to the North Central, and 7 percent to the western parts of the country. This was the case over much of the 1960's, with only the North Central region showing some increases over the period 1962-1968 (by three percentage points, while the North Central region was reduced by the same percentage).

The flow diagram shows how all these transactions work out in "normal" circumstances. At a given level of field prices, the additions to reserves meet the needs of the pipelines (as evidenced by their new contract demands). If not, and there is excess demand, then the prices these pipelines offer in new contracts increase above the previous level. Immediately, this brings forth more production from old contract reserves, brings forth some new contract reserves, and also cuts back on some of the marginal resale at the pipelines. After a time, the higher new prices also bring forth more new reserves and cut back on the long-term contracts sought by final buyers. Eventually at some level of new contract prices the amount of new reserve commitments by the producers is the same as the amount bought and resold by the pipelines.

1.1.3. The Effects of Shortages on Field and Wholesale Markets

Under "normal" conditions, the reserve and production markets operate to allow each pipeline buyer that "reserve backing" he desires, backing that makes secure the continuation of production to meet his commitments to residential and industrial consumers over the lifetime of their burning

---

[13] The process of setting markups on field prices is described in detail in Chapters 3 and 4, using a truncated version (in equation form) of FPC regulatory practice.

equipment. In a "shortage", the new discoveries fall short of the reserve amounts demanded by the pipelines in order to provide for the backing he seeks for his wholesale buyers. Under these conditions, the amount of actual field contract commitments are not equal to total "demands," but are equal only to "supply." At that point, the pipelines either (1) limit their commitments so as to preserve backing for old consumers or (2) draw down previously purchased reserves at a faster rate. If the second alternative is taken, production demands of final consumers could be satisfied for some period, as a result of the pipelines calling on existing reserves to produce at a higher rate,(thereby eliminating the reserve backing of old consumers). Thus reserve shortages in field markets may not be perceived by final buyers whose demands are temporarily satisfied by present production (as was the case in the late 1960's)[14]

Production to meet expanding demands from previous reserve commitments cannot be had indefinitely. Eventually, reserves from old commitments are reduced sufficiently so that the amount remaining limits the amount of production. As the reserve backing becomes smaller, production tends to fall, and a gap is opened between the demands for production and the amounts available. Many years may pass, however, before decline in additions to reserves is followed by a shortage of production.

Can the process be reversed? As indicated above, if prices were to increase in new contracts by a substantial amount, then more production could be gotten out of the previously committed reserves (because the price increase can compensate for additional costs from secondary recovery programs). This effect may be rather small, however, given that reserves have already been greatly depleted. But there would be a longer-term effect caused by

---

[14]This is surmised from the simulations with the econometric model, as shown for the 1960's and 1970's in Chapter 5.

price stimulation of the discovery process. Higher prices would add to incentives for exploratory drilling, and the drilling would increase new discoveries, extensions or revisions of reserves. After these additional reserves have been committed, the amount of production would then again be increased.[15] At the same time, over this extended period, demands for production would be curtailed by the higher price. Total demands would have increased because of increases in the size of energy markets (and increases in the prices of alternative fuels). But high gas prices should slow down the accumulation of new customers, so as to have a dampening effect on the size of the increased gas demands.

The combination of both reserve and demand incentives should be to reduce the excess demands. But it may take several years before the full effects of a price change are felt in field and wholesale markets. The period should be much longer than that required to complete the process of market clearing in grain or metals commodity markets. Under some conditions, however--with large price increases and new government policies on reserve discovery--it is expected that most of the shortages expected to occur in each region of the country can be reduced or even eliminated before 1980.

1.2. Gas Field Price Regulation by the Federal Power Commission

The history of regulation bearing on the gas shortage began 1954, with the Supreme Court's decision requiring the Federal Power Commission to regulate the wellhead prices on production into the interstate pipelines. This was an appeal in a case brought by the Attorney General of Wisconsin against Phillips Petroleum Company; Phillips' prices to the pipelines had been increasing, and higher prices were alleged to be contrary

[15] As shown by simulation with the econometric model, the results are given in detail in Chapters 2 and 5.

to the best interests of consumers in Wisconsin. In lower court testimony and briefs, arguments were made that the gas industry, while regulated at the pipeline level by the Federal Power Commission and at the retail level by the state regulatory commissions, was unregulated by government and even worse was controlled by the large field producers at the wellhead. Therefore field price increases, determined by a few large petroleum companies, could be passed through as "costs" in wholesale prices to result in final price increases to the consumer. Such pass throughs, it was argued, should be curtailed by the introduction of FPC regulation at the wellhead. The Supreme Court, without explicitly affirming that there was monopoly power in the hands of the producers, found that the Federal Power Commission did have the mandate to regulate the wellhead price.[16]

For the next five years, the Commission attempted to respond to the mandate. Price control at the wellhead covered first those contracts in the Phillips case itself, since that case had been remanded by the court for a finding of "just and reasonable " prices. The FPC first controlled price levels in the same way that state public utility commissions set limits on electric power or gas retail prices. The procedure begins by estimating (a) operating costs, (b) the allowed rate of return times the undepreciated original investment, and (c) depreciation of investment per unit of gas produced under a contract. These unit "accounting costs "

---

[16] Phillips Petroleum Company vs. Wisconsin, 347 U.S. 622 (1954). cf. E.W. Kitch, "Regulation of the Field Market for Natural Gas by the Federal Power Commission," Journal of Law and Economics (XI, Oct. 1968), pp. 243-281; Kitch notes on page 255 that "the court gave no reason for the regulation...considering the expertise of the Federal Power Commission... the court gave no indication of how the regulation was to be carried out."

are defined as equal to $\{[(a) + (b) + (c)]/q\}$ for q annual production. The permissible maximum level for average prices is set equal to these unit costs, or to "costs of service." The "cost finding" approach to price control was not readily applicable to Phillips, because part of the gas was produced with oil, which was not being regulated, and some was produced only after a number of dry wells had been drilled. Attributing previous "dry hole" costs to particular gas contracts, and attributing joint costs to gas or to oil, resulted in arbitrary limits on prices. Also, the usual standards for finding the proper rate of return--the average rate of return for public utilities--scarcely applied to an exploration and development company. In fact, higher returns were allowed to compensate for exploratory risk, but these were simply stated as being appropriate. It turned out that the prices proposed by the Commission were higher in some cases than the original prices objected to by the state of Wisconsin.

During this time the Commission, dealing in infinite detail with Phillips, was falling behind. The case had produced more than 10,000 pages of briefs and records; in the meantime, by 1962, more than 2,900 applications for price reviews had been filed by other companies. Management failure--the Commission itself forecast that it would not finish its 1960 caseload until the year 2043[17]--and the arbitrary nature of regulation together required the FPC to try other ways of controlling

[17] cf. Phillips Petroleum Company, 24 FPC 537 (1960), at 545.

field prices.[18]

The FPC turned to setting the same ceiling price for all transactions within a widely-defined geographical region. Temporary ceilings were set at market levels established a year or two previously (in the fashion of economy-wide "price freezes" common in the later 1960's). This way of regulating resulted in a freeze on prices at the 1958-59 level, so that new gas committed to interstate pipelines after 1961 had to be priced at a level not higher than the 1958-59 level. The freeze was to be temporary and was to be followed by "area rate" decisions which set permanent prices. The permanent prices were to be based on the average historical costs of gas within the region; and, in fact, considerable attention in the area rate proceedings was given over to calculating regional production costs, investment outlays, and rate-of-return averages.

---

[18] James M. Landis was particularly critical of the FPC's performance in the field of natural gas regulation, charging it with delays as well as with disregard of the consumer interest. He wrote:

"The FPC without question represents the outstanding example in the field of government of the breakdown of the administrative process. The complexity of its problems is no answer to its more than patent failures. These failures relate primarily to the natural gas field . . . These defects stem from attitudes of the unwillingness of the Commission to assume its responsibilities under the Natural Gas Act and its attitudes . . . of refusing in substance to obey the mandates of the Supreme Court of the United States and other federal courts. The Commission has exhibited no inclination to use powers that it possesses to get abreast of its docket . . . The recent action of the Commission on September 28, 1960 in promulgating area rates . . . has come far too late to protect the consumer . . . The Commission's past inaction and past disregard of the consumer interest has led the States to seek to force it it discharge its responsibilities . . . Delay after delay in certifications and the prescription of rates has cost the public millions of dollars . . . The Commission has literally done nothing to reduce the delays which have constantly increased . . . The dissatisfaction with the work of the Commisssion has gone so far that there is a large measure of agreement on separating from the Commission its entire jurisdiction over natural gas and creating a new commission to handle these problems exclusively . . . Primarily leadership and power must be given to its Chairman and qualified and dedicated members with the consumer interest at heart must be called into service to correct what has developed into the most dismal failure in our time of the administrative process."

See James M. Landis, Report on Regulatory Agencies to the President-Elect, December 1960.

The FPC, faced both with an enormous backlog of individual cases and with great difficulties in using orthodox procedures of price regulation in this industry, cut through the procedures to set regional maximum prices on the basis of regional average accounting costs. The new approach turned out to be as fraught with logical difficulties as the old approach. The Commission used estimates of regional costs from a period when temporary ceilings were in effect to set permanent ceilings. Since producing companies took on drilling projects with prospective costs less than forecast prices, and on average probably realized the expected level of costs, then the companies probably experienced costs up to the level of temporary ceiling prices. Thus, the FPC, noting that average costs were close to the temporary ceiling prices, found that the temporary ceilings were appropriate for permanent ceilings. Temporary ceilings set costs which set permanent ceilings.

Arbitrary or not, these prices did serve the Commission's interest, which seemed to be in preserving the price level of the late 1950's. No specific reason was given by the agency for preferring the early prices. Neither case materials nor Commission decisions showed they thought that prices should not be increased because such was dedicated by non-competitive producers.[19] Price increases seem to have been undesirable in and of themselves because they were subject to controversy (or could have been objected to by the pipelines) and because they could have run into difficulties in court review.[20]

---

[19] The "competitiveness of conditions" itself was never faced by the Commission. cf. S. Breyer and P.W. MacAvoy, Energy Regulation by the Federal Power Commission, Chapter 3 (Brookings Institution, Washington D.C., July 1974).

[20] cf. Breyer and MacAvoy, *op. cit.*, Chapter 3.

The courts added to the freeze by arguing that price increases were to be denied simply because they were increases. This is exemplified by the 1959 case in Atlantic Refining Company vs. Public Service Commission (360 U.S. 378) where it was stated that price increases were to be denied because "this price is greatly in excess of that which Tennessee pays from any lease in Southern Louisiana."[21]

The Commission's determination to "hold the line against increases in natural gas prices"[22] was sufficient to result in a constant price level on new contracts for gas going to the interstate pipelines during the 1960's. The weighted average new contract price was 18.2¢ in 1961, and 19.8¢ per thousand cubic feet in 1969 (in the intervening years the average price fell by approximately .6¢ per Mcf to a low of 17.6¢ in 1966).[23] The average wellhead prices on old and new contracts increased from 16.4¢ to 17.5¢ per Mcf from 1961 to 1969, primarily as a result of the replacement of very old contracts at low prices with new contracts at the ceiling levels close to 16¢ per Mcf.[24] These prices resulted in the consumer (at wholesale) paying approximately 33¢ per million Btu for natural gas

---

[21] This case is discussed in detail by Edmund Kitch in the article "Regulation of the Field Market for Natural Gas by the Federal Power Commission", Journal of Law and Economics, op.cit. p. 261. Kitch argues that "the court reasoned from the premise that prices higher than prevailing prices were questionable simply because they were higher." He shows that an examination of the increases that were occurring at the time does not support an argument that this was in response to demonstrated manipulation of the market by the producers.

[22] cf. Federal Power Commission, Annual Report for 1964 (vol.43), p. 15.

[23] These and data series described in the next few sentences are from the data bank used in compiling the econometric gas policy model. Appropriate references are provided in Chapters 3, 4, and 5.

[24] At the same time, average industrial drilling costs did not increase -- otherwise, they alone would have been the justification for regional price increases given the process of regulation. But the combined efforts of cumulative discoveries and faster rates of production must have increased marginal production costs. This is indicated by simulations with the econometric model described below, showing declining reserves additions at constant prices.

throughout the decade, with a range from 32.0¢ per million Btu in 1962 to 33.4¢ per million Btu in 1970). (At the same time prices for oil at wholesale increased from 34.5¢ to 39.8¢ and coal from 25.6¢ to 31.2¢ per million Btu.)[25] The Commission succeeded in holding gas prices down, while prices of other fuels were going up from 10 to 25 percent over the same time period.

Regulatory policy was reversed in 1971, with a series of FPC rate reviews and decisions that substantially increased the level of field prices. Based on "recognizing the urgent need for increased gas exploration and much larger annual reserve additions to maintain adequate service," the Federal Power Commission "offered producers several price incentives."[26] For those producing areas in the country containing more than 85 percent of reserves, the Commission increased prices by 3¢ per thousand cubic feet (in Kansas) to 5.2¢ per thousand cubic feet (in South Louisiana). These increases applied to new contracts signed that year. The FPC also began a proceeding (Docket R-389A) to set national ceiling prices on all new contracts, and showed some intention of providing substantial increases

---

[25] An example shows even greater disparities. Wholesale prices charged by Columbia Gas Transmission Company to the Baltimore retail gas company (Baltimore Gas and Electric) were 43.5¢ per mcf (or per million Btu) in 1970 as a result of frozen field prices, while wholesale terminal prices for #2 fuel oil were 86.3¢ per million Btu at the same location that year. Although retail delivery charges could explain part of the difference, it could not explain it all. The size of the difference increased by 30$ per million Btu per annum in the succeeding three years.

The oil and coal price series are from Edison Electric Institute, Statistical Annual of the Electric Utility Industry, for these fuels consumed in electric power stations; this is as close to a wholesale price series as can be obtained for comparability with gas sales by pipelines to either retail gas utilities, electric utilities, or other industrial users.

[26] cf. Federal Power Commission Annual Report, 1971 (U.S. Government Printing Office, Washington, D.C., 1972) p. 36.

by this route by new preliminary prices at the same time in the Rocky Mountain area 7¢ higher than those previously in effect.[27] Further increases were also promised as a result of the Commission establishing a procedure for certifying new producer sales above the prevailing area price ceilings. This procedure would allow higher prices when they were "shown to be in the public interest."[28] Although no explicit schedule of higher prices was forthcoming from the new exceptions, the setting out of an explicit path for avoiding the ceilings pointed to price increases.

In fact, the results of these policy changes have included a substantial increase in new contract prices in the last few years. The weighted average new contract price increased from 19.8¢ per thousand cubic feet in 1969 to 33.6¢ per Mcf in 1972. During 1973, the average new contract price probably rose to 36¢ per thousand cubic feet (although this is a preliminary estimate). The price freeze of the 1960's was in effect abrogated in the early 1970's with new contract prices increasing by 70 percent in four years. The question is whether this was "too little" and "too late" to clear excess demands for reserves and production over the rest of the decade.

1.3. The Behavior of Field and Wholesale Markets under Price Controls[29]

Institutional and political conditions together produced the shortage. The technical conditions of production resulted in long lags between new

---

[27] cf. Federal Power Commission 1971 Annual Report, op. cit., p. 42, "Initial Rates for Future Gas Sales from All Areas", Docket no. R-389A.

[28] cf. Federal Power Commission Annual Report for 1972 (U.S. Government Printing Office, 1973), p. 49.

[29] Much more detail could be provided on the operating practices, and regulation, of the pipelines before going on the describe the actual development of the shortage. The pipelines are regulated by the FPC on the basis of the procedures described above as"orthodox" public utility price controls, except on charges to direct industrial consumers or interstate consumers. Suffice it to say at this point that equities stressing "cost averaging" capture much of the results from this regulation in the econometric model in Chapters 3-5. The simulations from the model as a whole are stressed at this point.

TABLE 1.1: ADDITIONS TO RESERVES UNDER ALTERNATIVE CEILING PRICES, 1967-1972

Year	(1) New Contract Field Prices, (¢/Mcf)	(2) Total Additions to Reserves[1] (trillions of cu.ft.)	(3) Hypothetical "Unregulated" New Contract Field Prices (¢/Mcf)	(4) Hypothetical "Unregulated" Total Additions to Reserves[2] (trillions of cu.ft.)
1968	19.5	19.2	30.2	19.6
1969	19.8	17.8	36.6	18.7
1970	22.1	15.1	43.0	16.3
1971	25.6	14.4	49.7	15.9
1972	33.6	15.3	56.2	16.8

[1] Simulated using the econometric model with actual new contract field prices (cf. Chapter 5)

[2] Simulations with the econometric model using prices in column (3)

discoveries of gas and final production of that gas for the consumer. At the same time, however, regulation, by preventing price increase over most of the decade of the 1960's, was the critical precondition for emergence of excess demand.

The fixity of prices contributed to the winding down of exploratory activity and the resulting reduction in new reserves over the last half of the 1960's. This is shown by simulations of actual prices, with the econometric model, as reported in Table 1.1. Total additions to reserves, at prices on new contracts ranging from 18¢ to 33¢ per Mcf, declined over the period from 17 trillion cubic feet in 1967 to 15 trillion cubic feet in 1972 (with a low of 14 in 1971).

The reserves decline would not have been the case if new contract field prices had been higher. This is indicated by considering any of a number of alternative sets of prices in the econometric model--where each set is a possible replication of what unregulated prices would have been. There is no way of telling which set is more appropriate. But one likely hypothetical "unregulated" price, shown in Table 1.1, would probably have added more than a trillion cubic feet of additional reserves each year in 1969-1972 sufficient to prevent a drawing down of the total reserve stock.[30]

At the same time that new reserves were being added at a lower rate, gas pipelines were realizing increases in final demands at a higher rate.

---

[30]This price level was inserted into the econometric model in order to simulate, over the 1967-71 period, the behavior of additions to reserves. Reserves are estimated with the equation relationships for discoveries, extensions and revisions as a function of prices, costs, and potential reserve discoveries. This simulation is described in detail in Chapter 5. The basis for choice of the prices shown in Table 1.1 for "unregulated" was that they maintained a reserve to production ratio of 15/1 -- the lowest ratio actually experienced in the early and middle 1960's. Given that demands for reserve backing by final consumers was constant throughout the decade, this ratio is the lowest in keeping with equilibrium of demand and supplies of <u>reserves</u> as well as <u>production</u> throughout the period.

The pipelines then had the choice of either refusing buyers or of meeting expanded additional demands for production by taking from their inventories of old committed reserves. The companies in fact continued to meet new demands for production out of old reserves. There was no production shortage in the late 1960's or early 1970's; this is indicated, as shown in Table 1.2, by simulated "production" and "demands" in the econometric model being approximately equal each of these years.

Instead of drawing down reserves, the pipelines could have denied new customers access to the reserves. The interstate pipelines, acknowledging that there would be a reduction in the reserve backing then committed to established customers, could have refused to take on new customers unless they could be provided the reserve-production ratio available in the early 1960's. The level of production from this policy would have been less, as indicated by the model simulations reported in Table 1.3. The estimates for production at the constant R/P for the early 1960's, in Column (1), are approximately 4 trillion cubic feet less than actual production in Column (5) of Table 1.2. This difference is the amount "diverted" from the inventory reserved for old customers to provide immediate increased production.

This "reserve saving" alternative would have required cutting back production to less than would have occurred without price controls. The amounts expected without controls are shown as Column (2) of Table 1.2. These are from simulations with the econometric model at the hypothetical "unregulated" prices shown in Column (3) of Table 1.1 Both "reserve saving" and "no regulation" would have had less production than the actual amount because actual production was extended to meet extra consumption demands of new buyers induced into the gas market by the low frozen prices.

TABLE 1.2: FIELD MARKETS IN THE PERIOD 1967 to 1972

Year	(1) Average New Contract Field Price (¢/Mcf)	(2) Average Wholesale Price[1] (¢/Mcf)	(3) Simulated Production[1] (trillions of cu.ft.)	(4) Simulated Production Demand[1] (trillions of cu.ft.)	(5) Actual Production (trillions of cu.ft.)
1967	18.7	30.69	18.9	18.6	18.9
1968	19.5	31.30	20.1	19.6	19.9
1969	19.8	31.85	20.9	20.4	21.3
1970	22.1	33.23	21.8	21.2	22.6
1971	25.6	35.35	22.8	22.0	22.8
1972	33.6	38.43	23.6	22.7	23.3

[1] Simulated using the econometric model with actual new contract field prices (cf. Chapter 5)

TABLE 1.3: PRODUCTION UNDER ALTERNATIVE MARKETING PRACTICES OF THE PIPELINES, 1967-1972

Year	(1) Production at Constant R/P Ratio[1] (trillions of cu.ft.)	(2) Production at Hypothetical "Unregulated" Field Prices[2] (trillions of cu.ft.)
1967	16.8	18.6
1968	16.9	19.3
1969	17.0	19.5
1970	17.1	19.4
1971	16.9	19.0
1972	16.8	18.3

[1] Calculated by multiplying actual reserves each year by a 1/17 production reserve ratio.

[2] Simulated with the econometric model using the prices in Column (3) of Table 1.1.

The conclusion is that price ceilings imposed by the Federal Power Commission, in conjunction with long lags from prices increases to production, had a two-stage effect upon gas field and wholesale markets. First, the frozen prices reduced the amounts of reserves found over the last half of the 1960's. Second, the attrition in reserve additions was not matched by reductions in the growth of production. Rather, additional demands from both new and old customers were met by taking more production out of the existing reserve stock.[31] The established consumers with 15 to 17 years of reserve backing on annual production lost some of that backing, to the advantage of consumers receiving the expanded service, at least up to 1972. After 1972, there was not enough reserve backing to allow production to meet all of the increased wholesale demands, so that the "production shortage" then set in.[32]

The lags among reserves, production, and consumption makes it difficult to say who benefitted and who lost up to 1972. But customers in the Northeast, the North Central, and the West received a proportionately smaller share of the increased production out of old reserves, as compared to consumers in the Southeast and the South Central. This is indicated

---

[31]The demands in turn were increased by the relatively low prices at wholesale following from the frozen field prices. The additions to demands as a result of frozen prices can be seen from comparing "production demand" at actual average wholesale prices (shown in Column (4) of Table 1.2) with the demands that would have been realized at the hypothetical "unregulated" prices (shown in Column (2) of Table 1.3, which shows both production and demands at prices sufficiently higher to hold the 1965 reserve-production ratio through the rest of the decade). These "artificially induced" additions to demand from the lower frozen prices were of the order of 3 to 4 trillion cubic feet per annum by 1971-1972, and were realized mostly in the South Central and Southeast portions of the country as demands for boiler fuel that would have been met by residual fuel oil in the absence of the low gas field prices.

[32]The 1973-1974 production shortages are shown in the Federal Power Commission staff study of the supply and demand of natural gas (op. cit.) and in the econometric model simulations shown for those years in Chapter 2 below.

in Table 1.4, where demands at actual prices are compared with demands at hypothetical higher "unregulated" prices for each region and for each year. The differences, as derived from the econometric model simulations, indicate that demands were increased by relatively low frozen prices more in the South Central and Southeast (almost 45 percent of the increased consumption occurred in the South Central region alone). Since the increased demands were satisfied in large part by production out of old reserves, then, in effect, the backing for old customers was being used to cover additional demands induced by low prices in the South. This reallocation of consumption must be considered to be perverse, since those losing the reserve backing were customers under the protection of regulation, while those gaining the additional consumption were mostly intra-state or industrial consumers in the South not covered by Federal Power Commission regulation.

Can anything be said about the size of the dollar gains and losses from this pattern of regulation? Money estimates of benefits are exceptionally difficult to make. The gainers were customers not having to pay the higher "unregulated" prices for that amount of service actually received without any reduction in reserve backing. At least, on this consumption the service was still secure and the price had been held down. The losers were customers unable to increase their consumption without taking a reduction in reserve backing (or without undertaking additional risk of running out of gas before the end of the lifetime of their gas-using equipment).

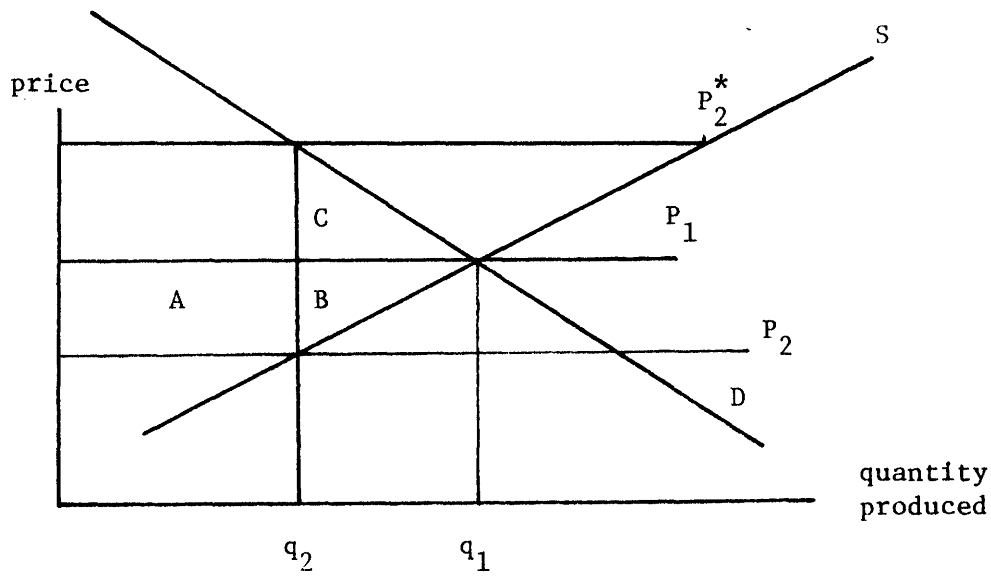
An approach to such measurement would begin with the first class of consumers. Their dollar gains should equal their consumption at constant R/P ratios times the difference between regulated and "unregulated" prices. The dollar loss of the second class roughly should equal one half of (a) the difference between their actual consumption and their

TABLE 1.4: REGIONAL PATTERNS OF DEMAND FOR GAS, 1967-1972

Year	Region	(1) Northeast			(2) North Central			(3) West			(4) Southeast			(5) South Central		
	Demands	(a)	(b)	$\frac{a-b}{\Sigma(a-b)}$	(a)	(b)	$\frac{a-b}{\Sigma(a-b)}$	(a)	(b)	$\frac{a-b}{\Sigma(a-b)}$	(a)	(b)	$\frac{a-b}{\Sigma(a-b)}$	(a)	(b)	$\frac{a-b}{\Sigma(a-b)}$
	$\Sigma(a-b)$															
1967	0	3.3	3.3		3.5	3.5		3.2	3.2		1.3	1.3		7.2	7.2	
1968	0.5	3.5	3.4	.20	3.8	3.7	.20	3.4	3.3	.20	1.4	1.3	.20	7.6	7.5	.20
1969	0.8	3.6	3.5	.13	4.0	3.8	.25	3.4	3.4	0	1.5	1.3	.25	7.9	7.6	.38
1970	1.7	3.7	3.6	.06	4.2	3.8	.24	3.6	3.4	.12	1.6	1.3	.18	8.1	7.4	.41
1971	3.0	3.9	3.6	.10	4.4	3.8	.20	3.6	3.4	.07	1.7	1.1	.20	8.4	7.1	.43
1972	4.2	4.0	3.6	.10	4.6	3.7	.21	3.7	3.4	.07	1.7	1.0	.17	8.6	6.7	.45

(a) Simulated from econometric model using actual prices.
(b) Simulated from econometric model using hypothetical "unregulated" prices.
$\Sigma(a-b)$ is the total difference across all margins.

Figure 1.2 Gains and Losses from Field Price Controls



hypothetical unregulated comsumption at constant reserve backing multiplied by (b) the difference between the unregulated and the "shadow" price (that would clear the market of regulated demand at constant reserve backing).[33]

Field producers experience losses from price ceilings as a matter of course. They lose by price ceilings those amounts gained by consumers on established service, and also lose roughly an amount equal to one-half the difference between regulated and unregulated prices times the difference between regulated and unregulated production.[34]

Any estimates of these price and quantity differences is most inexact, particularly because they depend on "unregulated" prices, when regulation throughout the decade has prevented observations of any such prices. Also, any overall assessment depends upon whether the gains to established con-

---

[33]This can be seen by inspection of the rudimentary supply-demand diagram, in Figure 1.1, as follows: the gains of established consumers are represented by Area A and the losses of consumers with reduced backing is shown by Area C.

The statement on prices in the text can be understood by inspection of the diagram. Here q_1 and q_2 are at the old reserve production ratio (since otherwise measurements of gains and losses would be made while "quality of service" in reserve backing was also being allowed to vary). The measures used here are the levels of production implied by constant R/p ratios shown in Table 1.3 The estimates for q_1 are given by production at hypothetical "unregulated" field prices (Column 2) and for q_2 by production at regulated prices at constant R/P ratio (Column 1). The price appropriate for regulated q_2 is P^*_2 which clears the market of the reduced quantity q_2 (resulting from the freeze at P_2). This price P^*_2 has been estimated by simulation with the econometric model.

There is also a loss by producers equal to Areas A and B. Again, these are measured at the mid-1960's constant R/P ratio, and thus are the same q_1 and q_2 as in the last paragraph. The net losses to all groups combined are equal to Areas B plus C, unless specific weightings are assigned to the "worth" of a dollar taken away from producers and a dollar given to consumers. Such a specific weighting of, say, 0.0 on the first and 1.0 on the second would attribute Area A to net economy-wide gains. No such attribution is made here.

[34]This is the number of dollars equivalent to Area B in the diagram in the preceding footnote.

sumers are treated as worth more than the losses of producers. Nevertheless, as an indication of the orders of magnitude of gains from the price controls, estimates of prices and quantities have been made from simulations with the econometric model. Field prices are as under regulation or, alternatively, at the simulated "unregulated" levels shown as being necessary to preserve the reserve backing. Alternative levels of production are as simulated at actual prices at a constant R/P ratio, or as simulated at hypothetical unregulated prices.[35] From these prices and quantities, the gains and losses have been estimated as follows:

Year	(1) Gains to Consumers (Area A) billions of dollars	(2) Losses to Consumers from a Reduction in Reserve Backing (Area C) billions of dollars	Losses to Producers (3) (Area A) billions of dollars	Losses to Producers (4) (Area B) billions of dollars
1967	0.3	0.0	0.3	0.0
1968	0.7	0.1	0.7	0.1
1969	1.2	0.1	1.2	0.1
1970	1.7	0.1	1.7	0.1
1971	2.2	0.1	2.2	0.1
1972	2.5	0.1	2.5	0.1

[34] This is the number of dollars equivalent to Area B in the diagram in the preceding footnote.

[35] The two simulation series for quantities are as shown in Table 1.3 as Columns (1) and (2) respectively. The Column (1) series is correct for regulated prices because it shows the amount of production at the "same" or constant R/P ratio. This amount is the proper level on which to assess gains of established consumers, since no reserve backing has been lost to that point. This takes account of net benefits after adjustment has been made for the losses to consumers from the elimination of reserve backing. The calculations of Areas A, B, and C are based on the assumption that the loss of reserve backing was equivalent to the reduction of present consumption at constant reserve backing, and that that reduction of present consumption is equivalent to the lowest level of production q_2 in the diagram above.

These are "static" gains and losses, since they include only one year's production results.[36] As limited as they are, they show that consumers as a group gained. What they gained, producers lost. The losses which would have gone into dividends to stockholders of gas companies, or into new investment in exploration and development, cannot be ignored entirely even if they were recognized by the regulatory commission. All that can be said is that the price freeze did more good <u>for buyers</u> in holding down their monthly payments of gas bills than the losses <u>to them</u> from reductions in reserves, and that the freeze did slightly more harm to producers in income and production losses.[37]

Whether this array of benefits and costs from field price controls will continue in the 1970's is the concern of the next chapter. During the later 1970's, the shortage of production consequent upon the reduced reserve backing should by itself lead to greater losses to established customers. An attempt is made in the next chapter to show whether there will still be net gains from regulation to customers then--particularly to interstate customers (since they are being protected by the Federal Power Commission from price increases).

1.4. Summary

The Federal Power Commission, having been given the task of regulating gas field prices by the Supreme Court, tried any number of ways of adapting old regulatory techniques to new contracts for producing gas reserves. The rationale for regulation provided by the courts centered on keeping prices

---

[36]Because of the extreme imprecision of the basis for estimates, a more complex dynamic analysis was ruled out at this point. Nor would the general results be further illuminated by discounting these numbers to present value at the time of the temporary area rates.

[37]That is, the sum of consumer gains (Areas A-C) falls slightly short of producer losses (Areas A+B).

at the levels experienced in the late 1950's; prices were to be stabilized for stability's sake. The Commission's resolve to hold the price level was strengthened by court decisions stressing that the FPC could set prices using whatever review process seemed most appropriate. Eventually, in the area rate proceedings, the FPC found the means for invoking freezes on prices over wide regions.

There is little question but that price stability was achieved. Stability probably led to deficiencies in supplies of reserves and, ultimately, deficiencies in production of gas in the early 1970's (as shown by simulations with the MIT econometric model described below. In the absence of controls, prices probably would have gone up enough to have maintained at least a fifteen-to-one reserve production ratio, and to have held back demands so as to have cleared field markets of all new reserve demands. Model simulations based on these conditions show that higher "unregulated" prices (sufficient to have cleared reserve markets)would have dampened demands and would have been at best 60 percent higher on new contracts, and when such prices were rolled in to wholesale changes, residential and commercial customers would have paid 20 percent more for the amounts they actually consumed.

To some extent, given these conclusions, the rationale for regulation can be judged in retrospect. Even though the courts and Commission are not explicit on who should receive the benefits from regulation, it might be assumed that those who actually <u>did</u> benefit were meant to be blessed by the regulatory process. Assuming such does not lead to a very clear and consistent view of regulation. Consumers, particularly in the South outside of FPC controls benefited from low prices on the production they received. But they and others lost their reserve backing, since old reserves were used to provide for expanded production for new consumers--indeed into the market by relatively low frozen prices. The model simulations of benefits and losses for particular groups indicate that consumers as a whole received benefits from lower regulated prices, even after accounting for losses for some from reduced reserve backing, and producers as a whole experienced losses to a somewhat greater extent than the consumers gained. Thus up to the beginning of the production shortage consumers at least may have benefited from controls. The rationale for regulation may have been no more than that of income redistribution to gas customers up to the point of production shortage. The rationale for the production shortage then remains to be found.

CHAPTER 2:

ALTERNATIVE REGULATORY POLICIES AND THE GAS SHORTAGE, 1974 - 1980

The development of production shortages in the last few years has had a strong effect on the conduct of regulation. Soon after the appearance of such shortages--manifest in the inability of pipelines to meet commitments to consumers--the Federal Power Commission, through the introduction of new regulatory procedures, brought about extremely rapid increases in new contract field prices. This was partly in response to widely-expressed opinions--from both producers and pipelines--that higher prices were needed to bring about more discovery activity and from that more production. However the lags in the system from price changes to more production which resulted were so extensive that, by 1974, there has been little production change from large price increases. The continued shortage has placed new pressures on the Commission for further changes in policy as well as in price levels.

At the same time Congress and the Office of the President have become focal points for complaints that FPC policies have failed to ameliorate gas production shortages. Many of these complaints have come from buyers--the pipelines and retail gas utilities--in the northern and western parts of the country feeling the production shortfalls. With neither producers nor consumers supporting gas regulation, there has been substantial pressure for change. The changes most often proposed have been in the realm of new legislation reforming the controls allowed the Federal Power Commission.

The proposals for legislative reform have been in two contradictory directions. The first is towards more regulation, while the second calls for elimination of Federal Power Commission controls over field markets.

The justification for moving in either direction is that the shortage would be reduced and consumption expanded for those users of gas needing it the most if the legislation is passed. However both justifications cannot be correct--either more of less regulation could be expected to reduce the shortage. but not both.

This chapter considers these alternative directions for policy, and evaluates each in terms of its ability to reduce the gas production shortage. No one specific bill before Congress, or specific rate schedule proposed to the FPC, is evaluated in detail, because legislation and cases change rapidly enough to render any such detailed evaluation quickly obsolete. Rather, attempts have been made to characterize policy and then to evaluate for each type its general effects on the gas shortage. Two classes of policies--(1) a reaffirmation of regulation and (2) deregulation of field prices--are described, and then evaluated in terms of the shortage by simulating with the econometric model to obtain predicted prices and quantities for 1975 to 1980.

2.1. Strengthened Regulation

Stronger controls over wellhead prices have been proposed before Congress and the Federal Power Commission. Many reasons have been given for this position, but most pervasive is the argument that producers have been holding back reserves in anticipation of relaxed controls. Because of the long lag structure from discovery to production, many years have to pass before there is any effect from higher new contract prices. It is argued that this period can be extended by producers if they think that future prices are going to be higher after regulation has been relaxed. The argument for tighter controls is that strict ceilings will cause producers to see the futility of holding back supplies and, as a consequence, more gas will be forthcoming at present prices.[1] The blame for the shortage lies with the FPC and its price increase policies: "[The FPC], with the best motives, has so tittilated the speculative expectations and ambitions of the producer industry with a promise of imminent deregulation and ever-higher prices, that it has become perfectly rational profit-maximizing behavior on their part to move slowly on development and production of reserves."[2]

The case for stronger regulation has been made with a different argument as well, that higher prices in fact will have little effect on the size of the shortage. This is asserted, for example, by Peter Schuck of Consumers Union when, after reviewing data on past increases in the price of natural gas and on the resulting quantity responses, he concluded that "deregulation would not significantly increase natural gas supplies.[3] This is asserted to be because the response of production to price is limited by the lack of competition in field markets. As concluded by Dr. David Schwartz of the Office of Economics of the FPC, "a review of the evidence indicates a lack of workable competition in the producer market (and) due to structural imperfections, deregulation would result in extensive prices, windfall profits to the producers, consumer exploitation

---

[1] cf. Testimony of Mr. Lee White, Chairman, Energy Policy Task Force, Consumer Federation of America, Hearings on Gas and Oil Regulatory Bills (U.S. Commerce Committee, 1973-1974) pages 457 et sic. White's argument is compromised by an attempt on his part to separate "increased demand" and "reduced supply" from "price" as factors contributing to the present natural gas shortage. (cf. page 478).

[2] Testimony of Peter Schuck, Director, Consumers Union, in Hearings on Gas and Oil Regulatory Bills (U.S. Commerce Committe, op. cit.) page 737.

[3] Testimony of Peter Schuck, op. cit.

and little assurance of adequate supplies of natural gas."[4] Although none are necessary for the case, the three arguments that are presented--(1) speculative non-response (2) low supply elasticity and (3) lack of competition--alleged together or separately, cause price increases to have no effect.

With no supply response, there is no need, in any way, for weakening price controls. In Schwartz' terms, "If administered fairly and firmly, regulation can assure an equitable framework for producers and consumers. . . . There is strong evidence that the present unavailability of gas supply is related to the speculative anticipations of significantly higher prices."[5] The thrust of any new policy would be to affirm ceiling price regulation as a price freeze process, with any frozen price level to hold for a considerable period of time in the future.

Many proposals have been made for determining the level of frozen prices and for deciding which producers should be subject to the freeze. Some have called for extending regulation to include intrastate sales, so that the "speculative outlet" of higher intrastate prices would be foreclosed. Others have proposed limiting the freeze to only the large producers. Proposals along the lines of the Consumer Energy Act of 1974

---

[4] Cf. testimony of David Schwartz, Hearings on Gas and Oil Regulatory Bills, op. cit., page 220. Others, particularly Professor Alfred Kahn, have argued that supply is inelastic (thus assuming that markets are competitive enough for there to be a supply function). Cf. testimony of A.E. Kahn, The Permian Basin Area Rate Proceeding FPC Docket ARG1-1(1960). This assertion was not supported by evidence on supply elasticities. The econometric policy model used below deals with the extent of market imperfection directly, by fitting equations for production out of reserves that contain terms for degree of market imperfection. These terms then are used in equations for prediction of future production in the econometric model (as described in Chapters 3 and 4).

[5] Testimony of David Schwartz, op. cit., page 221 and page 223.

proposed in the Senate (S.2506) called for abolishing the FPC alternative pricing procedures and establishing a national ceiling on prices of both gas and crude oil. The nation-wide rates would be based on historical costs plus a "fair rate of return" determined by an orthodox public utility rate review.[6] The goal of all those proposed stricter controls is to slow down the rate of increase of prices experienced in the 1970-1973 period, while adding to reserves and production.

If this goal is not achieved, so that no new legislation is passed, the FPC could continue its recent policies of increasing prices on new contracts by as much as 5¢ per Mcf each year. In doing so, the Commission is not likely to be hindered by the Courts of Appeal. The Supreme Court has continually affirmed the Commission's right to proceed; in the most recent case, the Court once again quoted the words of FPC Versus Natural Gas Pipeline Company whereby rate-making agencies "are permitted to make the pragmatic adjustments which may be called for by particular circumstances."[7] The courts "have consistently held that there is a presumption of validity that attaches to each exercise of the Commission's expertise. Those who would overturn the Commission's judgement undertake the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences.."[8] Within this context, the Commission

---

[6] But there would be more latitude within proposals to allow the Commission to consider in finding the rate of return "factors which are relevant to assuring that the nation has adequate supplies of oil and gas at reasonable prices to the consumer." Cf. "Congress Near Showdown on Proposal to Decontrol Gas Prices," National Journal Reports (May 25, 1974), page 772. The quotation is from a market-up version of the Consumer Energy Act, still in committee as of July 1, 1974. Although "supply and demand factors" could allow the Commission to set any price ceilings it wished, without reference to a Congressional mandate for stronger control, the goal of a price freeze is still predominant in this legislation.

[7] FTC v. Texas Inc. et al. 42 United States Law Week 4867 (June 11, 1974).

[8] Cf. Mobil Oil Corporation v. Federal Power Commission, 42 United States Law Week 4842 at 4855 (June 11, 1974). The words are quoted from the decision in Permian Basin Area Rates 390 U.S. 747 (1968).

has followed the practice of increasing prices on new contracts each year of the last few years, based in part upon historical cost considerations and in part upon price increases as the means for reducing shortages. This judgmental procedure, continued into the future, would be the "least vigorous" reaffirmation of regulation.

Thus there are two distinct alternative types of policies that could be characterized as "strong regulation." The first would be the product of new legislation, and would result in the installation of price freezes along the lines of the area rates of the early and middle 1960's. The general level of prices on new contracts would change only if the (extremely slow moving) historical average costs of production warranted changes. The second would, from default of Congress, be no new legislation, but would allow the Commission to exercise its "pragmatic" judgment that further changes in price levels were warranted. In such cirsumstances the Federal Power Commission, in keeping with decisions in the 1970's, to this point would likely allow changes in new contract price levels of up to 5¢ per Mcf per year.

2.2. Elimination of Regulation of Field Prices

The more widespread reaction to increasing production shortages has been the call for the removal of wellhead price regulation. Since prices were frozen over much of the 1960's, and shortages developed first in reserves in the middle 1960's and then in production in the early 1970's, it has been argued that controls were the cause. Furthermore, eliminating controls altogether should hasten the process of eliminating the shortage. The call for dereg ulation of wellhead prices on new contracts is asserted to be a first step in that direction. Calling natural gas "America's premium fuel," the President in April 1973 proposed legislation to exempt gas newly dedicated to the interstate pipelines from ceilings so as to "stimulate new exploration and development.[9] The same case was made by the Chairman of the Federal Power Commission by noting that "gas supplies are short and the way to encourage more drilling and discoveries may be to let prices rise."[10]

Deregulation as a policy is based on the argument that there is substantial responsiveness of both production and demands to price increases. Decontrol is the quickest way to take advantage of this responsiveness and thus to eliminate shortages. Although lag structures are not assumed away, most proponents of deregulation expect it to result in the elimination of the shortage in at least the near future. Decontrol should allow higher prices to clear markets of excess demand by increasing both reserves and production, and by decreasing demands at wholesale. Also, it would be expected that gas now being channeled away from controls into intrastate markets would go back to the interstate pipelines as the prices offered interstate either matched or exceeded those offered by local industry.

There is less than perfect agreement among proponents of deregulation as to how and over what time period decontrol should occur. The Republican Administration has proposed gradual or "phased" deregulation of new contract prices. Price ceilings would still be in effect on old contracts now delivering production, and the prices of new contracts would be allowed to increase only by steps over the next few years, until presumably by 1980 any further increases would be determined by market conditions alone. The step ceilings would be administered by the Federal Energy Administration, and would

---

[9] Cf. "Congress Nears Shutdown on Proposal to Decontrol Gas Prices " <u>National Journal Reports</u>, op. cit., page 764.

[10] Cf. "Federal Power Commission Head Urges End to Gas Curbs," <u>The New York Times</u>, April 11, 1973, page 19.

be based on forecasts of future production and economy-wide demand conditions rather than on backward-looking accounting costs. But total deregulation of all contracts has been proposed as well (Senate Bill 371, sponsored by Senator John Tower in 1973). Also, immediate deregulation of new contract prices has been proposed, and came close to passage as an amendment to other energy-related legislation (the Buckley amendment to the Energy Emergency Act of 1973).

There have been many reasons advanced for elimination of regulation other than that there would be a quick market-clearing response. Most basically, it is argued that the regulatory process itself produces systematic shortages, so that there is no way of even avoiding a shortage. This is because price changes lag behind costs under historical average cost rate-setting procedures. With rising resource costs there is no way that regulated prices can ever "catch up."[11]

Without going into the validity of these arguments justifying price decontrol, the question here is whether decontrolled prices would "do better" in the late 1970's. Would higher prices of the sort proposed for FEA significantly reduce the size of production shortages? This is an empirical question. The answer supports either the case for strengthened regulation ("low elasticity") or deregulation ("high elasticity").

2.3. Assessing the Effects of These Policy Alternatives

With long lags from price increases to more reserves and production, it might be expected that any policy would be effective only after a number of years had passed. Also, there would be only gradual changes in demands

---

[11]This point leads to questioning whether a process designed for public utility controls applies to a natural resource industry. Cf. Stephen Breyer and P.W. MacAvoy, "The Natural Gas Shortage and the Regulation of Natural Gas Producers," The Harvard Law Review (Vol.86, no.6, April 1973), page 941 et sic.

as a result of new contract price policies, since "rolled in" procedures pass field price increases through to wholesale price increases only after a number of years; after that, the wholesale prices affect industrial or final consumer demands. But even so it is expected that there would be some change in the first few years and a significant change by 1980. No political process taking a decade to show results is relevant in this system. Thus advocates of either (1) stronger controls or (2) decontrol expect their policies to eliminate the gas shortage and improve gas markets for consumers by 1980.

These possibilities are investigated by introducing the proposed policy changes into the econometric model of gas field and wholesale markets. Assuming certain rates of growth of production costs, of economy-wide determinants of demand, and of oil prices, the econometric framework leads to predictions of additions to reserves and production from each of twenty-nine production districts. There are also predictions from the model for residential and industrial demands in five regions of the country. By inserting new contract field prices consistent with each alternative policy into the modules for production, and by marking up field prices through roll-in pricing procedures in the modules for demand, predictions are made of reserves, production, and demands for each policy. Thus a policy can be examined in terms of the implications of its pricing schedule for levels of the production shortage.[12]

2.3.1. Strong Regulatory Controls of Field Prices.

Regulation could bring either a strict price ceiling for the rest of

---

[12]The last half of the 1970's, assuming a rather expansive economy, would have inflation rates of 6.5 percent, real growth of incomes and investment of 3.5 percent, and substantial oil prices (close to $7.00 per barrel in 1979 dollars).

the decade or, at the other extreme, price increases on new contracts by as much as 5¢ per Mcf per annum. The strict price ceiling would be in keeping with legislation calling for a return to public utility controls, as that offered by the Senate Commerce Committee in 1974. On the other hand, price increases by as much as 5¢ per annum would be in keeping with the Commission continuing its 1971-1974 price-increasing practices. Both of these pricing policies will be simulated with the econometric model, in order to determine their effects on production and demands. Also, an intermediate policy proposed recently will be evaluated in terms of its effects on production and demands.

The most restrictive of these strong controls would require a price freeze at the 1974 level, with adjustments allowed only for changes in historical average drilling costs thereafter. Given that average drilling costs in the last four years have increased close to the rate of 3¢ per Mcf per year, it can be expected that new contracts would be limited to the 1974 level of 39¢ per Mcf, with 3 cent increases thereafter (as shown in Table 2.1).

Such limited price changes would hold additions to reserves and production close to pre-1970 levels. The simulations indicate that new discoveries should increase somewhat, from the ten trillion cubic foot level in the early 1970's to 14 or 15 trillion cubic feet, but primarily as a result of the incentives to exploration which follow from the assumed high level of oil prices (close to $7 per barrel in real terms). Total additions to reserves would be less than 25 trillion cubic feet each year, while production would rise to as much as 30 trillion cubic feet. As a result, the reserve base would decline from 230 to 217 trillion cubic feet by 1980.

TABLE 2.1: ECONOMETRIC SIMULATIONS OF "STRENGTHENED REGULATION"

Year	New Discoveries (Continental U.S., trillions of cu.ft.)	Total Additions to Reserves (Continental U.S., trillion of cu.ft.)	Total Reserves (Continental U.S. trillions of cu.ft.)	Supply of Production (Continental U.S. trillions of cu.ft.)	Demands for Production (Continental U.S. trillions of cu.ft.)	Excess Demand for Production (Continental U.S. trillions of cu.ft.)	New Contract Field Price (Continental U.S. cents per Mcf)	Average Wholesale Price (Continental U.S., cents per Mcf)
1972	4.7	8.8	233.4	23.3	23.4	0.1	31.6	39.9
1973	10.1	17.5	228.3	23.7	24.2	0.5	34.6	41.6
1974	10.0	19.0	224.0	24.5	26.2	1.6	39.7	44.8
1975	12.8	21.6	221.7	25.3	28.7	3.4	42.7	48.5
1976	14.2	23.6	220.7	26.1	31.2	5.1	45.8	52.0
1977	15.6	25.3	220.8	26.9	33.7	6.7	48.9	55.7
1978	16.4	26.5	221.3	27.9	36.1	8.1	52.0	59.5
1979	15.7	26.1	220.5	29.0	38.5	9.5	55.1	63.4
1980	14.3	24.5	217.2	30.2	41.0	10.8	58.2	67.4

The model simulations show demands much greater than production with ceiling prices held at these levels. Total demands for new production are forecast to increase from 24 trillion cubic feet in 1973 to approximately 41 trillion cubic feet, as a result of the rapid increases in oil prices combined with the ceiling on gas prices (which prevents new contract prices from rising even as much as general price increases due to inflation.)

As a result, excess demands are expected to increase for the remainder of the decade. The gap between production and demand is forecast to increase as time passes, from approximately 3 trillion cubic feet in 1975 to 10 trillion cubic feet by 1980. The <u>ceiling price would appear to exacerbate excess demands</u> so that the shortage will be close to 25 percent of total demands for production by 1980.[13]

The Federal Power Commission itself has recently proposed a new form of regulation that inadvertently may have about the same effects. In its decision in Docket R389A case (considered "promising of future price increases" (as noted in Chapter 1), the FPC on June 26, 1974 allowed all gas produced from wells drilled after January 1, 1973 to sell at prices of 42¢ per thousand cubic feet. This uniform national rate would increase by 1¢ per annum thereafter. The ceilings were arrived at from review of

---

[13]These results from strict controls can be expected whether values of exogenous variables assumed here are used, or whether reasonable "higher" or "lower" values are used. As shown in the simulations in Chapter 5, when "high" values are used the size of the excess demand in 1980 is larger, and when lower values are used the excess demand is somewhat smaller. The results are approximately as sensitive to changes in oil prices as they are to changes in the values of economy-wide variables. Simulations based upon high versus low values of exogenous variables differ by approximately 7 trillion cubic feet in forecast excess demand for 1980. But this amount of difference, while substantial, does not affect the conclusion that strict regulation <u>cannot</u> eliminate the present natural gas shortage, and is <u>likely</u> to make it worse.

both costs and market conditions. The Commission did not expect these prices to be sufficient to clear excess demands immediately; the Commission said the demand for gas "is much higher than the supply and will remain so for the immediate future."[14] But the Commission in its judgment concluded that "these rates for natural gas sold in interstate commerce are adequate to bring forth the requisite supplies to fill reasonable demand" but "not so high that natural gas consumers are exploited during times of shortage."[15] These proposed prices are not different in kind from "strengthened regulation," because they require a low national ceiling and a small increase each year. By setting this national ceiling, the Commission has in effect frozen prices on some contracts already at the 42 cent level. These contracts are those with the most advantageous reserves and production (large in quantity and close to final delivery points); because these are frozen, the effect may be the same as a general price freeze, although the FPC did not intend it to be so. Also, the overall allowed increase of 1¢ per annum is significantly less than sufficient to compensate for expected inflation. Thus the effect over time as well as over space may be similar to a general price ceiling.

The forecast results are shown in Table 2.2. New discoveries are expected to be 30 percent less than under "cost of service" regulation in Table 2.1, and, given production close to 29 trillion cubic feet, the reserve stock in the United States is expected to fall below 200 trillion cubic feet by 1980. At the same time, demands are expected to be

---

[14] Cf. J.L. Rowe, "Price Boost Approved for Natural Gas," The Washington Post, June 26, 1974, quoting from the Commission decision in Dockets R389a, National Area Rates.

[15] J.L. Rowe, op. cit.

TABLE 2.2: ECONOMETRIC FORECAST FOR FPC "NATIONAL AREA RATE" REGULATION

Year	New Discoveries (Continental U.S., trillions of cu.ft.)	Total Additions to Reserves (Continental U.S., trillion of cu.ft.)	Total Reserves (Continental U.S. trillions of cu.ft.)	Supply of Production (Continental U.S. trillions of cu.ft.)	Demands for Production (Continental U.S. trillions of cu.ft.)	Excess Demand for Production (Continental U.S. trillions of cu.ft.)	New Contract Field Price (Continental U.S. cents per Mcf)	Average Wholesale Price (Continental U.S., cents per Mcf)
1972	4.7	8.8	233.5	23.3	23.5	.2	31.7	39.9
1973	10.2	17.5	228.4	23.7	24.3	.6	34.7	41.6
1974	9.9	18.8	223.6	24.9	26.3	1.4	42.0	45.2
1975	12.0	21.0	220.4	25.6	28.7	3.1	43.0	48.7
1976	12.6	22.0	217.5	26.3	31.3	5.0	44.0	51.4
1977	13.1	22.6	214.9	26.9	33.8	6.9	45.0	54.0
1978	12.7	22.5	211.7	27.7	36.5	8.8	46.0	56.5
1979	11.4	21.2	206.6	28.4	39.3	10.9	47.0	58.9
1980	10.2	19.6	199.5	29.1	42.4	13.3	48.0	61.1

enhanced by the low field prices and to grow to 42 trillion cubic feet by 1980. Excess demands are forecast to exceed 13 trillion cubic feet, or 30 percent of total demands. The forecast results imply that the Commission not only will be unable to reduce the shortage, but will create even greater excess demand than would occur by invoking old "cost of service" procedures on a regular basis through the rest of the decade.

A more promising alternative is the FPC form of regulation. The Commission, in the absence of new legislation, would continue its 1970-1973 policy of allowing average price increases each year on new contracts. Area rate reviews, along with individual case reviews, could result in five cent annual increases on new contracts. The basis would be the pragmatic judgment of the Commission as to what was necessary to ease a growing production shortage. As shown in Table 2.3, additions to reserves would be expected to increase by 1980 to approximately 30 trillion cubic feet per annum, as a result of substantial increments in discoveries, extensions and revisions. Production would be expected to fall slightly short of the total additions to reserves each year. As a result, the total stock of reserves would be expected to decline somewhat by 1976, but to return to the level of 230 trillion cubic feet by 1980.

Unfortunately, neither the additions to reserves nor the level of production would appear to be sufficient to eliminate the shortage. Simulated demands increase at a slightly lower rate than under the two alternative regulatory policies discussed above, principally as a result of the average wholesale price increasing from 48¢ to 72¢ over the period from 1975 to 1980. Even so, the demands of 39.9 trillion cubic feet by 1980 exceed production by 8.3 trillion cubic feet. Worse still, because of smaller additions to production than to demand, the shortage is expected to increase. Excess demand is a smaller percentage of total demand than under strict "cost of service" regulation, but still exceeds 20 percent of total demands. In this case, as with the previous simulations of "strengthened regulation," policies that result in small annual price increases do not of themselves eliminate the shortage of production. Price ceilings would appear to make the shortage worse.

2.3.2.. Phased Deregulation of Field Prices

Given the large number of alternative proposals under the rubric of "deregulation" of field prices, no single price schedule can be proposed for an exact depiction of market conditions under decontrol. Most proposals, however, would allow new contract prices to seek their own levels after 1980, with increasingly higher ceilings on new contract prices in the intervening period.[16] The ceilings in fact would not eliminate excess demand in the middle 1970's, because they would be set to prevent substantial price increases in the immediate future. Many rules of thumb have been proposed for setting the interim prices; among the most frequent is that of keeping average wholesale prices from increasing by more than 100

---

[16]It should be stressed that "phased deregulation" is in no way a synonym for complete deregulation within a few months' time. Although complete and instantaneous deregulation is an alternative being considered, it has not been examined here for political and economic reasons. The chances of its acceptance by Congress seemed so small that it did not merit space in this short chapter. Also, there is no analytically acceptable procedure for simulating complete deregulation, since the equation relationships in the model were constructed on the basis of data for two decades in which regulation was predominant. Extrapolation of relationships during regulation, to indicate other relationships in unregulated markets, seems unacceptable; the chances in patterns of price expectations alone would be so great as to eliminate any similarities of producer performance under the two regimes of control. Simulations of "phased deregulation" over the next five years seem to be legitimate, since they involve the continued use of price controls of the nature of those in the 1960's and 1970's when the data for equation estimation were generated.

TABLE 2.3: ECONOMETRIC FORECAST FOR FPC REGULATION

Year	New Discoveries (Continental U.S., trillions of cu.ft.)	Total Additions to Reserves (Continental U.S., trillion of cu.ft.)	Total Reserves (Continental U.S. trillions of cu.ft.)	Supply of Pro-Duction (Continental U.S. trillions of cu.ft.)	Demands for Production (Continental U.S. trillions of cu.ft.)	Excess Demand for Production (Continental U.S. trillions of cu.ft.)	New Contract Field Price (Continental U.S. cents per Mcf)	Average Wholesale Price (Continental U.S., cents per Mcf)
1972	4.7	8.8	233.4	23.3	23.4	0.1	31.6	39.9
1973	10.1	17.5	228.3	23.7	24.3	0.6	34.6	41.5
1974	10.0	19.0	224.0	24.5	26.2	1.7	39.7	44.6
1975	13.2	22.1	222.0	25.4	28.8	3.3	44.7	48.6
1976	15.3	24.7	221.9	26.4	31.2	4.8	49.8	52.7
1977	17.6	27.4	223.6	27.3	33.5	6.1	54.9	57.2
1978	19.4	29.8	226.7	28.6	35.7	7.1	60.0	62.1
1979	19.9	30.7	229.5	30.0	37.8	7.8	65.1	67.2
1980	18.8	29.7	230.2	31.5	39.9	8.3	70.2	72.4

percent over the 1975-1980 period.[17] Using wellhead prices in keeping with such interim ceilings, a representative sequence would include a 25 cent increase in 1975, with 5¢ per annum increases thereafter. Simulations with this price sequence have been completed as representative of price and production behavior under "phased deregulation."

The simulations indicate increased discoveries each year, up to 29 trillion cubic feet by 1980, and total reserves to the level of 270 trillion cubic feet by that year (as shown in Table 2.4). The impact of the price increases on new discoveries would not occur immediately, but rather would begin to appear in the second and third year after the 25 cent price increase. Production out of reserves would increase somewhat faster than reserve accumulations themselves since production depends on price as well as the reserve level. As a result, simulated production rises from 23 to 35 trillion cubic feet, at the rate of more than 1 trillion cubic feet per annum.

At the same time, simulated demands for gas are reduced as a result of the pass-through of the higher new contract field prices to the wholesale level. In fact, wholesale prices are not expected to increase very rapidly.

---

[17] These price equivalents were presented to members of the House of Representatives in individual briefings in the Spring of 1974 by the Columbia Gas System, 20 Mountchanin Road, Wilmington, Delaware as a basis for legislative proposals allowing higher gas prices. As a matter of fact, they would allow price increases that would still not place natural gas prices at the same level as oil prices forecast for New Jersey in 1980. The sequence of such "equitable" prices would be as follows. Gas wholesale prices start at approximately 44¢ per Mcf in 1974 and increase to 88¢ per Mcf in 1980. The final price is equivalent to crude oil prices close to $5 per barrel. But the addition of further delivery charges to places as far North along the eastern coast of the United States as New Jersey would add at least 30¢ to these average nation-wide wholesale prices. The resulting East Coast oil and gas prices would be $7 per barrel in 1980 dollars--the level of oil prices in 1974 dollars used in the econometric forecasts.

TABLE 2.4: ECONOMETRIC FORECAST FOR PHASED DEREGULATION POLICY

Year	New Dis-coveries (Conti-nental U.S., trillions of cu.ft.)	Total Addi-tions to Reserves (Conti-nental U.S., trillion of cu.ft.)	Total Reserves (Conti-nental U.S. trillions of cu.ft.)	Supply of Pro-Duction (Conti-nental U.S. trillions of cu.ft.)	Demands for Pro-duction (Conti-nental U.S. trillions of cu.ft.)	Excess Demand for Pro-duction (Conti-nental U.S. trillions of cu.ft.)	New Contract Field Price (Conti-nental U.S. cents per Mcf)	Average Wholesale Price (Conti-nental U.S., cents per Mcf)
1972	4.7	8.8	233.4	23.3	23.5	0.1	31.6	39.7
1973	10.1	17.5	228.3	23.7	24.3	0.6	34.6	41.3
1974	10.0	19.0	224.0	24.5	26.3	1.7	39.7	44.3
1975	16.7	25.5	224.1	26.8	28.6	1.8	64.6	52.8
1976	21.6	31.2	228.8	28.1	30.5	2.3	69.7	59.2
1977	25.3	35.8	237.1	29.2	31.9	2.7	74.8	65.3
1978	29.8	41.4	249.5	30.9	33.2	2.2	79.9	71.8
1979	29.8	42.8	261.5	32.9	34.2	1.2	85.1	78.1
1980	28.9	41.8	270.7	35.0	35.1	0.1	90.3	84.1

(The average wholesale price up to that point in time rises only to 84¢ per Mcf, while the new contract field price in 1980 is 90¢ per Mcf.) Even so, the price increases are sufficient to hold demands down to the level of 35 trillion cubic feet per annum by 1980. "Phased" increases in gas prices curtail the growth in demands for production by almost 36 percent (as compared to FPC regulation with 3 cent per annum price increases).

The results of this policy would seem to include a substantial reduction in the gas shortage within a reasonable time span. By 1979 the levels of production and demands for production are both expected to be approximately 35 trillion cubic feet. Of course there is some chance that there would still be some shortage, given that these forecasts, based upon the "probable" values of economy-wide determinants of costs and demands, are not going to be perfectly accurate. But the most likely general price increases, oil price increases, and gas increases (in keeping with phased deregulation) should clear production markets of excess demand.[18] In comparing this with "strict regulation" policies, it would appear that this is the policy more appropriate for eliminating the gas shortage. The process would be extended over many years, and would

---

[18] As in keeping with the simulations for "strict control," attempts have been made to assess the precision of the forecasts. The approach consists of inserting different values of exogenous variables into the econometric model to determine how the size of forecast excess demand changes. The different values of exogenous variables are discussed below, in Chapter 5. But, even with a wider range of values than likely would occur, the size of the shortage as a result of this phased deregulation policy does not vary greatly. There would be a shortage as large as 2 trillion cubic feet if either "high" oil prices or "high" economic factors prevailed; but if low values of both exogenous oil prices and economic variables were in effect, the shortage would be a surplus as large as 6 trillion cubic feet at prevailing phased deregulation prices. Under these last circumstances, it would be expected that the price ceilings would not "operate." Prices would be below ceiling levels, or reserves would be put back into the reserve inventory rather than produced (so as to raise the reserve-production ratio).

involve large field price increases. But "phased deregulation" should reduce the shortage to negligible levels by 1980, while more regulation would likely increase the shortage so that the excess demand would range from 8 to 13 trillion cubic feet out of 40 trillion cubic feet of total demands per year. If the goal is to eliminate the shortage, as those proposing policy changes all espouse, the proper direction would seem to be that of "phased" deregulation.

TABLE 2.5:

TAXES ON CONSUMPTION

TO ELIMINATE THE GAS SHORTAGE

Year	Field Price on New Contracts ¢/Mcf	Taxes on New Contracts ¢/Mcf	Production Supply trillion cu. ft.	Production Demand with Taxes trillion cu. ft.
1974	39.7	0	24.6	26.3
1975	44.8	10.9	25.4	28.7
1976	49.8	21.9	26.4	30.6
1977	54.9	32.9	27.4	31.9
1978	60.0	43.9	28.7	32.5
1979	65.1	55.0	30.1	32.3
1980	70.2	66.0	31.5	31.2

Of course there are other ways of eliminating the shortage, but they are more expensive for the consumer and/or the taxpayer than "phased deregulation." Consider two alternative policies deliberately designed to eliminate the gas shortage. The first is to tax consumption so as to reduce demands to the level of 31 trillion cubic feet--that level of production forecast to occur under continuation of regulatory "status quo." As simulated by the econometric model, the taxes levied on pipeline buyers in new contracts would have to begin at 10¢ per Mcf in 1975 and rise to 66¢ per Mcf in 1980 (as in Table 2.5). These taxes would be added onto new contract field prices, so that the pipeline pays 136¢ per Mcf for new gas at the wellhead in 1980. When these prices are "rolled-in", they would be sufficient to cut back on wholsale and final demands so as to eliminate excess demands.

The shortage could be eliminated by increasing gas supply an additional 10 trillion cubic feet. This could conceivably be done by subsidies on new contracts added to the controlled prices paid--subsidies that would provide income to the producer, but would not add to the field or wholesale prices paid by the buyers. Table 2.6 shows the subsidies required to bring forth the additional supply necessary to match the demands, given a regulatory price freeze, of 39.9 trillion cubic feet . The simulations from the econometric model suggest that this could be achieved by 1980 with subsidies of more than $1 per Mcf on new contracts, so that the field producers would receive $1.78 per Mcf that year on new commitments to interstate pipelines. In this case, the "price" of $1.78 per Mcf on new contracts would be "split" between buyers and taxpayers.

Both of these policies would seem more costly than phased deregulation, simply because each uses only one-half of the market at any time. The tax policy uses the "demand dampening" mechanism of increasing prices to consumers, while the subsidy policy uses the "supply expansion" mechanism of increasing profits to producers. But "phased deregulation" uses both supply and demand incentives, so that the amount of price increases or profit per unit of "excess demand reduction" is less than with either of the fiscal policies.

TABLE 2.6

SUBSIDIES TO ELIMINATE

THE GAS SHORTAGE

Year	Field Price on New Contracts ¢/Mcf	Production Demand trillion cu. ft.	Subsidy on New Contracts ¢/Mcf	Production Supply with Subsidy trillion cu. ft.
1974	39.7	26.3	0	24.6
1975	44.8	28.8	17.9	26.6
1976	49.8	31.3	35.9	28.9
1977	54.9	33.6	53.8	30.7
1978	60.0	35.8	71.8	33.3
1979	65.1	37.9	89.9	36.2
1980	70.2	39.9	108.1	40.0

2.4. The Effects of Gas Policy Changes on Producers, Consumers, and Others

The superiority of the "phased deregulation" policy, at least insofar as reducing the shortage is concerned, is so great that there would seem to be little basis for support of the alternatives. But there is substantial concern over the income effects from policies centered on working only on the shortage. Consumers are subject to substantial price increases from deregulation, which recur to producers as higher profits.

The effects involve more than simple income gains or losses. The shortage itself affects incomes. Curtailments this last winter in the use of gas in the North in residential and commercial consumption left consumers with lower *real* incomes.

In fact, there may be important groups of consumers that would gain from phased deregulation. Residential consumers already not attached to a retail gas utility company would gain from phased deregulation if they were allowed to join the system because there was increased production available. Industrial consumers would gain because they would receive gas that otherwise would not be available to them. Northern consumers would benefit most from decontrol at the expense of consumers in the South Central part of the country.

These patterns are indicated in Table 2.7. Under "status quo" regulation, excess demand would be greatest in the North Central and second greatest in the Southeast region of the country.[19] If all residential demands in the North Central and Southeast are met, as a result of allocation requirements by the FPC that residential consumers be served first, then the excess demand there has to be realized by industrial buyers. Thus from 90 to 100 percent of industrial demands in those regions would have to be cut off, with buyers going to alternative fuels and/or curtailing production of final products and services. Thus, given the most likely pattern of control over who gets the shortage, the industrial consumers in the North Central part of the country would receive "real income" or benefit from "phased deregulation" more than anyone else.

Price decontrol would have an impact on other industries--particularly other energy industries--so that they would be important "gainers" and "losers" as well. In the presence of excess demand for domestic natural gas, a new industry could develop in the early 1980's to provide gas from other

---

[19] There would be less excess demand in the Northeast and West, because of access to pipelines going into the more likely productive new field areas, particularly offshore and in the Permian Basin. There is expected to be no excess demand in the South Central region, because higher intra-state prices in that region allocate additions to reserves to buyers there first.

TABLE 2.7

SHORTAGES BY REGION, 1978 - 1980

Year	Northeast: Excess Demand (a)	Total Residential Demand (b)	Total Industrial Demand (c)
1978	0.7	2.9	2.4
1979	0.7	3.0	2.4
1980	0.7	3.0	2.5
	North Central: Excess Demand (a)	**Total Residential Demands (b)**	**Total Industrial Demand (c)**
1978	4.3	3.9	4.6
1979	5.0	4.1	5.1
1980	5.6	4.3	5.6
	West: Excess Demand (a)	**Total Residential Demand (b)**	**Total Industrial Demand (c)**
1978	0.2	1.8	3.0
1979	0.3	1.9	3.1
1980	0.4	2.0	3.3
	Southeast: Excess Demand (a)	**Total Residential Demand (b)**	**Total Industrial Demand (c)**
1978	1.7	1.1	2.1
1979	1.8	1.3	2.3
1980	1.9	1.4	2.3

Source: Simulations with the Econometric Model derived from regulatory "status quo" conditions. All estimates in trillions of cubic feet.

parts of the world. Liquified Natural Gas would take the place of domestic natural gas not developed under price controls. This Liquified Natural Gas, presumably from North Africa or the Soviet Union, could eliminate excess demands; at FPC regulated prices, it is forecast that LNG prices could exceed $1.00 per Mcf delivered into the North Central region for demands greater than 4 trillion cubic feet (if the LNG prices were "rolled in" to wholesale prices before being passed on to wholesale and retail consumers). LNG prices could exceed $2 per Mcf and demands would still be greater than 2.5 trillion cubic feet that year. But under phased deregulation, there would be negligible excess demands by 1980; in effect, the market for LNG is "made" by strong regulatory controls. Phased deregulation would make LNG producers and transporters losers."[19]

Of course there are always specific groups of potential gainers or losers from industry-wide changes in regulatory policies. The losers from phased deregulation like LNG companies are "special interests" not likely to be mistaken for the general consumer, when the rationale of consumers' interests is invoked for or against regulatory policy changes. The substitution of LNG at $2 per Mcf for domestic natural gas at 80¢ per Mcf must be considered a special interest proposal for solving the natural gas shortage in the period 1975-1985.[20]

---

[19] No attempt is made here to describe the full market for LNG, and LNG as a "solution" to the gas shortage. This would require an analysis and forecasts of foreign reserves, production out of reserves, and of demands in other countries than the United States. These would call for a world gas econometric model. However, these demand forecasts for LNG are described in detail in Chapter 5.

[20] But it should be noted that these special interests are economically substantial. The licencing of LNG contracts by the Federal Power Commission would create large-scale new construction of storage facilities and of LNG tankers in domestic United States ship years. These facilities add considerably to the rate base for profit regulation of wholesale pipelines or retail gas utility companies, and this rate base is welcomed in a period when the capital base from construction of pipelines in the 1950's has been in a good part eliminated. Thus important parts of the pipeline industry constitute a group of beneficiaries from the shortage or of losers from phased deregulation.

Another group affected by changes in regulatory policies are producers and distributors of crude oil in the United States. If the FPC price controls were to be continued, and the resulting shortage given to industrial users, then the demands for distillate and residual fuel oil would be substantially increased (in the absence of a Liquified Natural Gas industry). The econometric model has been used to simulate the changes likely to occur in fuel oil markets, by assuming that alternatives are either "phased deregulation" prices or FPC prices.[21] Forecasts are then made of fuel oil demands in the Northeast under these two sets of gas controls. They indicate that residual demands will increase by 1.0 million barrels and distillate demands by .3 million barrels per day as a result of the gas shortage. Similar results in sections of the country with even larger shortages indicate a substantial increase in fuel oil consumption from regulation.[22] The loss of these markets from "phased deregulation" would constitute another "interest group" which loses from decontrol.

This is not to deny that some consumers are favored by regulation and that they would lose if it were discontinued. Being able to get all the gas demanded in 1970 prices for the rest of the decade is a favorable position, wherever created by strict regulation. It would be expected that the income transfers away from these consumers resulting from "phased deregulation" would exceed 1 billion dollars per annum by 1975 and 3.7 billion dollars by 1980 (where the alternative to "phased deregulation" would be a continuation of FPC regulation). This income transfer would go

---

[21] The procedure consists of finding that price P^*_2 in Figure 1.1 that clears excess demands for gas (since the model does not recognize excess demands for one fuel as the determinants of demands for another fuel). Then oil demands at P^*_2 are compared with oil demands at P_2.

[22] Forecasts cannot be made of increased fuel oil demands in the North Central portion of the country, because of inability to construct a demand equation for fuel oil in which gas prices were a significant variable. This vagary of the data of the 1960's prevents use of the approach in this paragraph for evaluating the impact of the shortage where it is greatest on fuel oil demands in that region.

from consumers with uninterrupted service to oil and gas.[23]

But accompanying this loss from "phased" deregulation, there are gains to those other consumers who otherwise would do without. The gas not forthcoming at controlled prices is available for industrial and commercial use in the northern parts of the country. The dollar gains from deregulation, measured by the prices these consumers would be willing to pay for this gas rather than do without in the period 1978-1980, is forecast to exceed 2.5 billion dollars (in 1978) and 5.6 billion dollars in 1980.[24] Thus this group is expected to incur greater gains from deregulation than those who lose from no longer receiving the gas at lower prices. Since these are all consumers--there would seem to be <u>general gains from deregulation</u> for consumers as a group through phased decontrol at this time. Only if the appropriate horizon for political decision-making were less than two years would support for more regulation seem to make sense from the point of large groups of consumers.

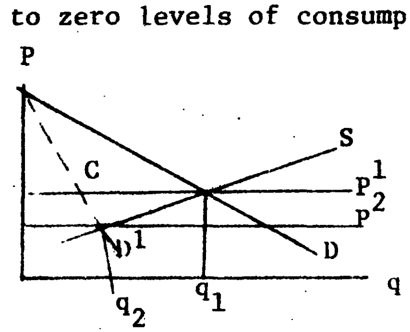
2.5. The Rationale for the Shortage and Regulation

Naming the "gainers" from phased deregulation is not to assert that certain groups resisting deregulation benefit from the shortage, and that they have influenced policy out of self-interest. The "demands" for regulation

---

[23] The amount of "gain", estimated from the simulation results described below, is equivalent to Area A in the diagram in Chapter 1.

[24] This is equivalent to Area "C" in the diagram in Chapter 1, except that, because consumers are doing without <u>entirely</u>, this area extends from the level of consumption to zero levels of consumption as follows:



Thus these losses are particular to the regulatory procedures used by the Federal Power Commission and the state commissions of allocating the shortage <u>entirely</u> to new consumers and to industrial consumers in the regions experiencing excess demand.

from special groups would not seem to have controlled the "supply" of strict regulation to date--at least not in an obvious way, since losers from deregulation compose a very motly group which seems to change rapidly.[25]

Rather than purposeful regulation, there would seem to have been a classic failure of process in natural gas fuel price controls. The regulatory mechanisms were mandated by court decisions, calling for price stability without reference to market conditions of production or demand. These court decisions imposed a task on the Federal Power Commission that it was not able to perform; eventually the consumer was in fact made worse off by their ceilings on prices, arrived at in the same way that more appropriate ceilings are found for electricity prices. The failure of controls as a means to benefit the consumer would seem to have been a failure of logic and perspective.

The failure of logic comes from reasoning by analogy. The process of regulation used by the Commission followed time-honored procedures. The FPC dealt in calculations of historical costs, and in finding a fair rate of return by comparing profit rates with those in other industries. These methods of control had been an accepted part of public utility regulation for decades. But these methods had not been applied systematically

---

[25] In the late 1960's and early 1970's, residential consumers in most parts of the country, and all consumers in the South Central part of the country, gained from price regulation. Certain of the pipelines that had very large reserves were gainers from price controls, because their field purchase prices didn't go up with new contract prices frozen under regulation. These groups no longer benefit from regulation. Certain of the pipelines would gain in the future from continued regulation from the sales of liquified natural gas; and certain oil producers experiencing large increases in fuel oil sales in industrial regions consequent from the gas shortage would continue to benefit from regulation. Some residential consumers, under firm delivery in the South, probably could expect a few more years of consumption at low prices under regulation. Naming these categories of producers and consumers as "losers" from the phase decontrol and designating them as a coalition for continued regulation would not appear to be credible at this time.

to the gas industry, where costs of new reserves- even more expensive to find--could not be determined from historical accounting data on old reserves. New prices based on old costs guaranteed that increments to production would in the long-run fall short of increments to demands. By asserting that controls developed in one setting would work in the other, the regulatory agency made logical errors that undermined the efficiency of the results.

To this was added the failure of perspective. Taking a two-to-three year view of price ceilings, when industry reserve accumulation and production took place over much longer periods, was incorrect. Since this view still predominates in legislative proposals for reform--where results are expected from new price policies immediately--this part of the mistake could well be repeated. The only question that remains is how long it will take to understand these mistakes and to learn from them in revising regulatory policy.

CHAPTER 3:

THE STRUCTURE OF THE ECONOMETRIC MODEL OF NATURAL GAS

3.1. Overview of the Econometric Model

The econometric model developed for the natural gas industry has the important characteristics of (a) simultaneously describing the behavior of both reserves and production markets (b) describing the regional organization of the industry at a disaggregated level and (c) accounting for the time-dynamics inherent in the various activities of the industry. There are good reasons for including this level of detail in the model.

In order to analyze the effects of alternative regulatory policies, it is necessary that the industry be viewed as a complete system. Most previous econometric studies of natural gas have investigated either supply or demand, but have neglected the simultaneous interactions of the two. Balestra,[8] for example, in his classic study of the demand for natural gas by residential and commercial consumers, assumed perfectly elastic supply (as was probably justified for the 1950's and 1960's, since deliveries to final consumers were then made on an "as needed" basis. However, this would not be valid for a model of the 1970's where total demands for gas exceed production. Given that prices and other variables now affect both production and demands, our model accounts for the simultaneous interaction of output and demand at both field and wholesale levels of the industry.

Regulation has been in effect for both field sales and tranportation of gas. Consequently two distinct sets of markets must be accounted for in modeling the gas industry. Production and demand must be described in both the market for reserve additions (gas producers dedicating new reserves to pipeline companies at the wellhead price) and the market for wholesale deliveries (pipeline companies selling gas on long-term contracts to retail utilities and industrial consumers). Furthermore, the spatial relationship of these two markets must be modeled properly.

These markets are regional in nature; reserve additions are contracted for in regional field markets, and gas production is delivered by pipelines to regional wholesale markets. These regional markets are interconnected through the network of natural gas pipelines across the country. Individual wholesale markets receive gas from different combinations of producing markets, so that it would be possible for a shortage of natural gas production to exist in another wholesale region. In analyzing regulatory policy and its impact on natural gas shortages, it is thus necessary to account for this spatial organization of field and wholesale markets.

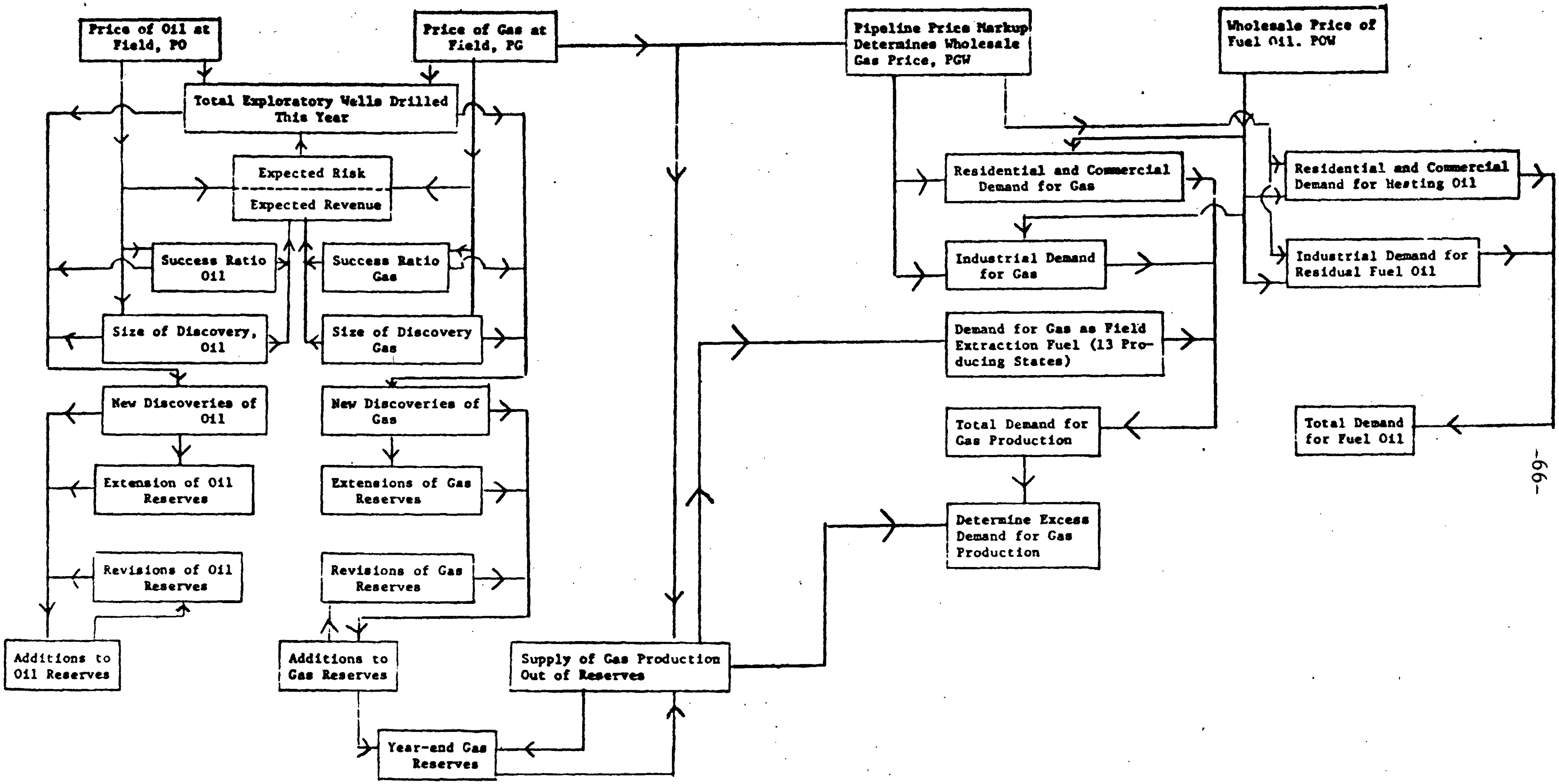
The time-dynamics of the different stages of reserve accumulation, of production, and of demand are an important aspect of the model. Policy questions center on not only how much production or demand will be forthcoming at higher regulated prices, but also on how long it will take for the effects of a new pricing policy to occur. Attempts are therefore made to include appropriate time lags in all of the relationships of the model.

A block diagram of the model is shown in Figure 3.1, and should provide an overview of both the model's organization and the relationships between field and wholesale markets. This diagram ignores (for simplicity) the spatial interconnections between production districts and regional wholesale markets, but it nonetheless provides a good starting point for understanding the model's structure. We will therefore broadly survey each part of the model with reference to the diagram and then discuss the individual modules in more detail later.

3.1.1. Gas and Oil Reserves

Reserve additions are made up of new discoveries, and extensions and revisions of previous discoveries. New discoveries include both associated and nonassociated gas (associated gas includes both gas "dissolved" in produced

Figure 3.1 Block Diagram of the Econometric Model



oil and gas forming a cap in contact with crude oil). New discoveries also provide the major component of reserve additions for oil.

The discovery process begins with the drilling of wells, of which some will be successful in discovering gas, some will be successful in discovering oil(with or without associated gas), and some will be unsuccessful (i.e., dry holes). Although wells are drilled in regions which offer some probability of gas or oil discovery, many are drilled without an a priori expectation of one specific hydrocarbon. As a result, the exploration and discovery process for both gas and oil are considered simultaneously.

Drilling takes place under two modes of behavior, depending on whether it is done extensively or intensively. On the extensive margin, few wells are drilled, but those that are drilled usually go out beyond the geographical frontiers of recent discoveries to open up new locations or previously neglected deeper strata at old locations. There the probability of discovering gas is relatively small, but the size of any discovery may be large because it would be the first in the region. On the intensive margin many wells are drilled in an area already the source of gas production. Under these conditions the probability of discovering gas is larger, but the size of discovery is likely to be smaller.

The producer who is engaged in exploratory activity has, at any point in time, a portfolio of drilling options available on both margins. In deciding where to drill, producers make a trade-off between expected risk and expected return, and thereby decide whether additional drilling will be extensive or intensive. This choice between extensive and intensive drilling will be influenced by changes (or expected changes) in economic variables such as field prices of oil and gas and drilling costs.[1] The model developed here has an

---

[1]See Fisher [28].

equation for wells drilled which is based on a rational pattern of producers' responses to economic incentives in forming their portfolios of intensive and extensive drilling.[2]

Drilling alone does not establish discoveries in the model. Equations are specified to determine the fraction of wells drilled that will be successful in finding gas, and the fraction successful in finding oil. These "success ratios" depend on whether economic incentives (e.g., price increases) result in drilling on the extensive or intensive margin (and this must be determined empirically). For example, suppose that the choice is on the extensive margin. In that case the gas success ratio depends positively on the size of gas reserve found per successful well (the larger reservoir is easier to find), negatively on changes in the gas price (higher gas prices mean more extensive drilling for gas), and positively on the oil price (higher oil prices relative to gas prices result in more intensive drilling for gas since oil becomes relatively more profitable).

Two equations determine, for gas and oil respectively, the size of discovery per successful well. Discovery size is related to the number of successful wells drilled previously, to the volume of previous discoveries in that region (or to the "age" of fields there), as well as to gas and oil prices. A larger number of previous successful wells means that discovery sizes will be smaller, since the larger reservoirs are found earlier. The "age" of fields itself is a function of how much previous drilling has been done, so that size decreases with age. If economic incentives result in

[2]Economic incentives affect the number of exploratory wells drilled through the determination of expected risk and expected return. This is done by calculating returns as functions of current gas and oil prices, and also through average drilling costs and the interest rate (reflecting captial costs). Expected revenue per well is the sum of expected gas revenue and expected oil revenue, where each expected revenue is the product of current price, the estimated success ratio and the estimated size per successful well. Expected risk is an estimate of the variance of expected revenue.

extensive drilling, then higher gas prices (or lower oil prices) result in larger discovery size as a shift is made to the extensive margin.

Finally, the model generates forecasts of new discoveries from this set of equations. Total new discoveries (calculated for gas and oil separately) is the product of number of wells, success ratio, and size of find per successful well. This level of detail allows us to give explicit consideration to the process of long term geological depletion as well as the role of risk in determining the amount of exploratory activity. We account for the fact that, from the viewpoint of exploration, oil and natural gas are in fact joint products, and must be treated symmetrically. Also, this framework allows for shifts in the relative proportions of intensive and extensive drilling in response to changes in economic incentives.

Additions to reserves also occur as a result of extensions and revisions of existing reserves. These extensions and revisions for both gas and oil depend theoretically on 1) price incentives 2) past discoveries of gas and oil 3) existing reserve levels for both gas and oil and 4) the cumulative effect of past drilling. In fact, extensions seem to be influenced most by past discoveries and total drilling activity.[3] Revisions of established reserve levels, on the other hand, seem to be essentially proportional to prior discoveries and reserve levels.

As can be seen in the block diagram, additions to gas reserves are the sum of new discoveries, extensions, and revisions. Aside from changes in underground storage, subtraction from gas reserves occurs as a result of production. Similarly, additions to oil reserves are the sum of new discoveries of oil, extensions, and revisions. Since our model does not explain the production of oil from reserves, we do not determine

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

year end oil reserves.[4]

These partly engineering, partly economic equations determine additions to reserves made by petroleum companies. If the natural gas industry were not regulated, or if regulation of the wellhead price were ineffective (i.e., if the ceiling price of gas were the equilibrium wellhead price), this model would also contain demand equations for reserves. In particular, the demand for new reserves would be given by a wellhead price 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 wellhead ceiling price.[5]

3.1.2. Natural Gas Wholesale Markets

The level of natural gas production out of reserves depends not only on the size of the reserve base, but also on prices that buyers are willing to pay for larger deliveries. The formulation of production supply in this model has the marginal cost of developing existing reserves determine a particular level of annual flow (e.g., by drilling development wells and then operating them). Marginal production costs are dependent on reserve levels relative to production, so that as the reserve-to-production ratio becomes smaller, marginal costs rise sharply. The exogenous regulated price is assumed in turn to set the upper bounds on marginal costs. Thus, as can be seen in

---

[4] A separate "sub-model" for reserve additions (as well as production out of reserves) was constructed for offshore Louisiana, but is not shown in the block diagram. Certain onshore data used for the exploration and discovery equations described above were not available for offshore (e.g., detailed success ratio data), and furthermore offshore exploration as well as production depend to some extent on different variables than is the case onshore (e.g., the number of acres leased). The offshore submodel permits us to examine additional policy alternatives relating, for example, to acreage leasing.

[5] Note that it is possible to have at the same time excess demand for new reserves but clearing in production markets by running down the existing reserve-production ratio. This was in fact the case in the late 1960's.

the block diagram, the level of gas production out of reserves is a function of both the field price of gas and the quantity of year end reserves in any one production district.

The level of production out of reserves must be assessed relative to the demands for that production after it has been transported to wholesale markets by pipelines. The wholesale demand for natural gas production is a function not of the wellhead price of gas but rather the wholesale price. Average wholesale prices for gas are computed in the model for each consumption region in the country through a series of pipeline price markup equations. The price markups are based on operating costs, capital costs, and regulated rates of profit for the pipeline companies.

Of course wholesale gas prices are not the only determinants of wholesale gas demand. Residential and commercial demand, and industrial demand, depend as well on the prices of alternative fuels (including the wholesale prices of oil), and "market size" variables such as population, income, and investment which help determine the number of potential consumers. Separate residential/commercial and industrial equations are formulated for each of five regions of the country. There is a third category of natural gas demand which is formulated within the model, and that is the demand for gas as field extraction fuel. A certain quantity of gas is used as fuel for operating pumps to extract gas from the ground in the thirteen major producing states, and although this quantity is small it should be modeled to determine properly the total gas demand.

Natural gas is competitive with fuel oil both in industrial and residential/commercial markets. When analyzing the impact of alternative regulatory policies, it is desirable to determine not only the changes in the demand for gas, but also how changes in gas demand are related to changes in oil demand. We would like to know, for example, whether a decrease in the demand for gas resulting from a higher price of gas results in an increase in the demand for fuel oil, as well as how changes in the price of fuel oil affect the demand for natural gas. The model therefore contains a set of wholesale demand equations for fuel oil. Fuel oil demand is disaggregated into residential/commerical demand (for numbers 2 and 4 oil) and industrial demand(for number 6 residual oil). Separate equations are estimated for each of three consuming regions: the North East, the North Central, and a "South" region which includes the South East, South Central, and West regions of the country. The fuel oil demand equations have the same structural form as do the natural gas demand equations, thus making it possible to compare changes in oil and gas demand in a consistent manner. As can be seen from the block diagram, these demands for oil depend on the wholesale prices for both oil and natural gas, and also on the same "market size" variables as gas demand.

The determination of natural gas production at the wellhead and, concurrently, the volumes delivered to buyers in wholesale markets, is accomplished in the model by an input-output table connecting production districts with consuming regions. A flow network is constructed which, based on the relative flows calculated from 1971 data, determines where each consuming region obtains its gas. This flow network also determines the pipeline price markups for gas, since those markups are functions of the volumetric capacities of the pipelines as well as the mileages that gas must be transported across the country.

Once the model has been spatially closed, wholesale deliveries can be determined and summed to produce total deliveries for each region of the country. Then, given the forecasted demands from the wholesale demand equations, we can forecast excess demand on a regional basis.

3.2. Structural Equations for Gas and Oil Reserves [6]

The process of exploration and discovery, and the resulting accumulation of new reserves, are probably the parts of the oil and gas industry that are the most difficult to capture in a conceptual model. The exploration and discovery process is complicated, and has not been studied (or modeled) in detail by engineers. Thus structural econometric relationships formulated to link economic, geological and technological variables that govern reserve additions are likely to be rather crude at this time. Attempts are made here to formulate those relationships that show clearly the effects of regulatory policy, and that can be said to be based on maximization assumptions.[7]

The model for reserve additions describes the process of generating new discoveries of oil and natural gas in two stages. The first stage describes investment in exploration under conditions of geological uncertainty and a continuing process of depletion of the hydrocarbon resource base. Exploratory companies are assumed to choose a level of investment that maximizes the firm's value after balancing expected returns against the expected risks and corresponding costs involved in exploration. Combined with a characterization of costs of exploration and development, this analysis leads to an expression for the number of exploratory wells drilled in each production district. In the second stage, the model predicts the parameters of the size distribution of drilling prospects, and updates them from period to period

---

[6] This section and section 4.3 are based on Krishna Challa's Ph.D. dissertation "Investment and Returns in Exploration and the Impact on the Supply of Oil and Natural Gas Reserves," M.I.T. Sloan School of Management, 1974.

[7] Thus an attempt is made to go beyond simply connecting independent and dependent variables in a "black box" formulation. At a number of places in the model particular relationships are posited from maximization of producer or consumer utility. At other places, however, where theory failed us, "black box" formulations are involved.

to reflect the continuing process of reduction in prospects as well as new information on geological and economic variables. Equations for the ratio of successful to total wells, and for the size of discovery (conditional on a success), are formulated so as to depend on these parameters. Discovery volumes are then the product of wells drilled, success ratio, and discovery size per successful well.

Additions to proved reserves also occur as a result of extensions and revisions of existing fields and pools. Extensions and revisions are modeled as functions of previous discoveries, exploratory wells drilled, existing levels of accumulated reserves and production, and an index of geological depletion.

3.2.1 The Number of Exploratory Wells Drilled

The aggregate industry function for exploratory wells drilled is, of course, the composite of the individual drilling decisions of several explorers operating simultaneously. The individual driller makes his decisions after taking into account the currently available information that can help him ascertain expected return and risk in exploratory drilling, as well as the relevant costs. Individual firms have a range of drilling options available, each with its own expected risk and expected return, and a set of options is chosen that maximizes the present value of the certainty equivalent net cash flow resulting from exploration. To obtain a "certainty equivalent" there must be a measure of the risk in any chosen set of drilling options; we assume that risk can be represented by the variance of the cash flow, so that the present value in certainty equivalent terms of the net cash flow to the j^{th} firm is given by

$$V_j = (1/r)(\overline{\pi}_j - \lambda\sigma_j) \tag{1}$$

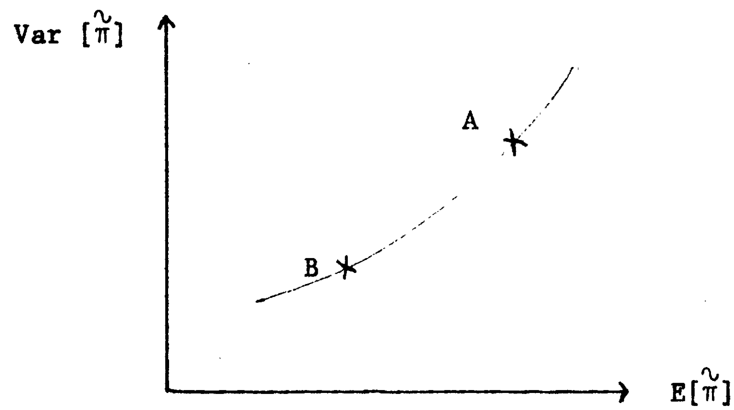
where $\tilde{\pi}_j$ is the total end-of-period cash flow to firm j, $\bar{\pi}_j = E(\tilde{\pi}_j)$ is the expected value of $\tilde{\pi}_j$, σ_j is the variance of $\tilde{\pi}_j$, λ is an index of risk aversion, and r is a long-term market interest rate.[8]

Now let us examine how each firm can choose drilling options that will maximize V_j. At any point in time there is an inventory of undrilled prospects about which some information is available. Maximizing behavior on the part of the risk-averse explorer leads to the choice of prospects that yield the highest expected return for a given level of risk, or, conversely, prospects that have the lowest level of risk for a specified mean return. These prospects are on an <u>efficient frontier</u> which may be represented as an upward sloping curve in the risk-return plane, as shown in Figure 3.2. The frontier includes small and relatively certain prospects (which correspond to <u>intensive</u> drilling) such as point B, as well as large but less certain prospects (corresponding to <u>extensive</u> drilling) such as point A. The particular prospect chosen would depend on the individual driller's preference for risk. The more risk-averse he is the more likely it is that he will choose prospects

---

[8] This is based on the single-period mean-variance model for pricing of capital assets under uncertainty developed by Sharpe [80], Lintner [50] and Mossin[62]. Consider a single-period world in which all investors are expected utility maximizers whose investment decisions can be characterized by the maximization of a preference function $U_i(W_i, e_i, V_i)$ where W_i is the individual's wealth at the beginning of the period, e_i is the expected value of the cash flow to be generated one period hence by the investor's portfolio, and V_i is the variance of this cash flow. If one assumes that $\partial U_i/\partial W_i > 0$, $\partial U_i/\partial e_i > 0$ and $\partial U_i/\partial V_i < 0$, and that all investors have homogeneous expectations and that transactions costs and taxes are zero, then the certainty equivalent of the random cash flow $\bar{\pi}_i$ has a risk discount equal to the product of the price per unit risk λ and the risk itself. The risk of the cash flow is given by the sum of its variance and covariances with cash flows from other investment opportunities. We assume that (a) the alternative to drilling is an investment at return r, and (b) drilling risks are independent across firms (so that the probability of success at a site owned by firm A is independent of whether or not firm B drilled successfully at another site). Under these assumptions the covariances are zero and the risk of a cash flow is given by its variance.

Figure 3.2 Efficient Frontier



yielding small but relatively certain returns - i.e., that he will drill intensively.

Once a well is drilled, oil and/or natural gas might be discovered. Suppose that in a given period the j^{th} explorer is considering drilling a set of independent prospects which are expected to yield mean dollar receipts $\overline{RW}_j$ per exploratory well from oil and gas discoveries. Let $(RW)_j^v$ represent the corresponding variance of dollar receipts per exploratory well. The expected net return $E(\tilde{\pi}_j)$ from drilling W_j wells may then be expressed in terms of $\overline{RW}_j$ and $C^e(W_j)$, the expected total costs of exploration and development if W_j wells are drilled:

$$E(\tilde{\pi}_j) = W_j\overline{RW}_j - C^e(W_j) \quad . \tag{2}$$

If $\overline{RWG}_j$ and $\overline{RWO}_j$ are the mean sizes of discoveries respectively of natural gas and oil per exploratory well, $(RWG)_j^v$, $(RWO)_j^v$ the corresponding variances, and PG^e and PO^e the expected prices of natural gas and oil respectively, then we may write

$$\overline{RW}_j = k(\overline{RWG}_j PG^e + \overline{RWO}_j PO^e) \tag{3}$$

and

$$E(\tilde{\pi}_j) = k(W_j\overline{RWG}_j PG^e + W_j\overline{RWO}_j PO^e) - C^e(W_j) \tag{4}$$

where k is a multiplicative factor that accounts for the fact that discoveries may be extended or revised later in the development process.

Probably the largest source of uncertainty in returns from exploration is geological unpredictability, i.e. the randomness of discovery size. For simplicity the economic parameters will therefore be assumed to be known with certainty so that

$$\text{Var}\ (\tilde{\pi}_j) = W_j (RW)_j^v \tag{5}$$

or

$$\text{Var}\ (\tilde{\pi}_j) = k^2[W_j(RWG_j)^v (PG^e)^2 + W_j(RWO_j)^v (PO^e)^2] \tag{6}$$

if no significant correlations exist between oil and gas discoveries.

Before we can determine the number of wells to be drilled we must examine the components of total expected costs, $C^e(W_j)$. These include the costs of exploration C_E and the costs of subsequent development activity C_D. Although there is little theory establishing a functional relationship between exploration costs and wells drilled, we can observe that (a) costs vary in total and at the margin from one production district to another, depending on average well depth, rock permeability and other geological conditions, and (b) costs per well in a given drilling district seem to rise with the total number of wells drilled in that district within a specific period, i.e., average costs are increasing. Based on these empirical regularities, exploration costs can be characterized by a quadratic function, so that the costs of drilling W_j wells are:

$$C_E(W_j) = \alpha + \beta W_j + \gamma (W_j)^2 \quad . \tag{7}$$

The historical average drilling costs per well $(\overline{ATC})$ vary from district to district because of the geological conditions of depth, permeability and porosity. Using the historical values of $\overline{ATC}$, we posit that

$$\beta = \beta_o + \beta_1 \overline{ATC}$$

which gives us

$$C_E(W_j) = a_o + a_1 W_j + a_2 \overline{ATC} + a_3 (W_j)^2 \tag{8}$$

where a_o, a_1, a_2 and a_3 are constant parameters.

The cost of subsequent development activity is governed partly by the same geological factors that affect exploratory costs (e.g., depth, rock permeability, shape of the decline curve, type of drive, etc.) and also by the amount of reserves withdrawn from the ground. This leads us to assume

$$C_D(W_j) = k_o + k_1 W_j \overline{RW}_j + k_2 \overline{ATC} \quad . \tag{9}$$

Substituting expressions (8) and (9) into (2), we obtain an expression for expected net return of the form.

$$E(\tilde{\pi}_j) = b_o + b_1 W_j + b_2(W_j \overline{RW}_j) + b_3(W_j \overline{ATC}) + b_4(W_j)^2 \quad . \tag{10}$$

We now substitute equation (5) for σ_j and equation (10) for $\overline{\pi}_j$ in equation (1), and then differentiate the resulting expression with respect to the number of exploratory wells drilled (so as to maximize V_j). This gives us the following expression for WXT_j, the total number of exploratory wells drilled by firm j:

$$WXT_j = c_0 + c_1 \overline{RW}_j + c_2 (RW_j)^V + c_3 \overline{ATC} \quad .$$

Aggregating over all firms in the district, we expect the same relationship to hold:

$$WXT = c_0 + c_1\overline{RW} + c_2(RW)^V + c_3(\overline{ATC}) \quad . \tag{11}$$

Here $\overline{RW}$ and $(RW)^V$ stand for the values of the mean and variance of dollar receipts over all of the exploratory wells drilled in the district.

Because of the "one-period" nature of this formulation, the riskless interest rate r cancels out and does not appear in the final expression for total exploratory wells drilled. This would be correct only if costs and corresponding revenues occurred in the same period; but since there are in fact considerable lags between investment outlays for exploration and the accrual of revenues from discovered and produced reserves, we include an interest rate term INTA as an additional explanatory variable in equation (11). Adding this term, and substituting the aggregate average values of the parameters RWG, RWO, $(RWG)^v$ and $(RWO)^v$, we obtain the estimating equation for exploratory wells to be:

$$WXT = c_0 + c_1\ (\overline{RWG}\cdot PG^e + \overline{RWO}\cdot PO^e) + c_2\ [(RWG)^v(PG^e)^2 + (RWO)^v(PO^e)^2] + (\overline{ATC}) + c_4\ (INTA)\quad . \tag{12}$$

3.2.2. The Geological Environment as It Affects Size of Discovery

A single production district will in general contain reservoirs of distinctly different geological types. Following Kaufman *et al*. [41] we assume that reservoirs can be classified into a finite number of geologically homogenous "*sub-populations*". A *play* begins when an exploratory well leads to the discovery of the first reservoir in a particular sub-population. Drilling then continues in the sub-population until the economic returns from drilling no longer compensate for the associated costs and risks.

This description of the physical evolution of a play relies on three postulates suggested by Kaufman et al. [41], and supported by earlier empirical studies including Arps and Roberts [6], Kaufman [40], and Uhler and Bradley [85]:

I. The size distribution of reservoirs within a sub-population is lognormal.

II. Conditional on a discovery being made within a sub-population, the probability that the discovery will be of a given size is proportional to the ratio of that size to the sum of sizes of as yet undiscovered reservoirs within that sub-population.

III. Conditional on a play beginning within a sub-population, the probability that an exploratory well will be successful in finding a new deposit is proportional to the ratio of the sum of volumes of the as yet undiscovered deposits to the total unexplored volume of potentially hydrocarbon bearing sediment.

Postulates I and II together can be used to determine the probabilistic behavior of the amounts of oil or gas discovered by each successful well in the order of discovery. Postulate II implies that on the average the larger reservoirs will be found first, and that as the discovery process continues, sizes of discovery tend to decline. Postulate I, II and III together imply that within a given sub-population, as the play unfolds, the probability of success tends to decrease, as does the average size of discovery. The result, then, is to shift the efficient frontier of Figure 3.2 towards the left. This may in part be compensated for by addition of some new, hitherto unknown, prospects to the <u>efficient</u> set, but these additions are the result of new geological information acquired during the activity of exploratory drilling in the previous period, and are relatively unpredictable.

3.2.3. The Size of Discovery

We can now develop the dynamics of the size distribution of reservoirs as drilling continues. Let δ_k represent the mean rate of decline in the size of new reservoirs discovered in the k^{th} sub-population, expressed in volumes of hydrocarbons per successful exploratory well drilled. Let $\mu_k(t)$ be the mean size of the discovery at time t in the k^{th} sub-population, and $\tilde{s}_k(t)$ a random variable representing the anticipated size of the next reservoir discovered in this sub-population. Based on the postulates cited above, $\tilde{s}_k(t)$ may be assumed to be <u>lognormally distributed</u>, at least to a reasonable approximation. Then if $WXS[t_1, t_2]$ denotes the total number of successful exploratory wells (gas or oil) drilled into the k^{th} sub-population during the time interval $[t_1, t_2]$ the anticipated size of the next reservoir discovered at time $(t + h)$ would be lognormally distributed with

$$E[\tilde{s}_k(t + h)] = \mu_k(t) - \delta_k\mu_k(t)WXS_k[t, t + h]$$
$$= \mu_k(t + h) \tag{13}$$

and

$$Var[\tilde{s}_k(t + h)] = \mu_k^2(t + h)\,\sigma_k^2 \tag{14}$$
$$= \mu_k^2(t)\sigma_k^2 \qquad \text{for small } h$$

where σ_k^2 is the variance parameter associated with the lognormal density governing $\tilde{s}_k$. The parameters δ_k and σ_k are characteristics of the k^{th} subpopulation and are assumed to remain constant over the range of geological depletion we are concerned with. Thus, over a small interval of time h, the mean rate of decline in the size of discovery per successful well drilled is

$$\frac{E[\tilde{s}_k(t + h)] - \mu_k(t)}{\mu_k(t)WXS[t, t + h]} = \delta_k \tag{15}$$

and the variance of the rate of decline per successful well (for small h) is[9]

$$\frac{Var[\tilde{s}_k(t + h)]}{\mu_k^2(t)} = \sigma_k^2 \tag{16}$$

Under our set of assumptions, as long as an estimate of the mean size of reservoirs μ_k at some initial point in time is available, knowledge of the values of the two parameters δ_k and σ_k is sufficient to describe the dynamics of the probability distribution of discovery sizes. This is true in the following sense. Given an estimate of the mean size of $\mu_k(t_0)$ at some initial point in time t_0, we can predict (using (15) and (16) repeatedly) the

---

[9] As we will see in the next chapter, since the error variance in (16) is constant over time, we can estimate δ_k by ordinary least squares regression to estimate the relationship in (15) without the expectation operator on the left-hand side. The standard error of regression in this estimation would directly give us a consistent estimate of the variance parameter σ_k^2.

mean size of discoveries, and the variance of the sizes, at any subsequent point in time t_1. This holds as long as we know the number of successful wells drilled into this sub-population $WXS[t_0, t_1]$ during the interval between t_0 and t_1.

This procedure for determining discovery size distributions will have to be modified however. Four modifications will be undertaken, with a goal partly to improve the specification of the model and partly to facilitate use of a better econometric procedure for fitting the model. First, although it has been assumed that observations of $\tilde{s}_k$, the size of individual discoveries, are used, we must use the average $\bar{s}_k[t-\theta, t+\theta]$ of the sizes of all reservoirs discovered in a specified small interval of time $[t-\theta, t+\theta]$. Second, in equation (15), the term $(\bar{s}_k(t + h) - \mu_k(t))/\mu_k(t)$ denoting an estimate of the percentage change in average size during the time interval $[t, t + h]$ will be replaced by $\Delta(\log \bar{s}_k)$. We can rewrite equation (15) in the more convenient form

$$\log (s_k(t + h)) = \log (\mu_k(t)) - c_0 WXS_k[t, t + h] \quad . \tag{17}$$

The value of c_0, when estimated in a regression equation, provides a direct estimate of δ_k.

The third modification requires more detail. We have thus far assumed that the parameter δ_k, representing the mean rate of decline in size, is constant throughout the evolution of discovery in a subpopulation k. This may not be an unacceptable assumption during the earlier stages, when the size of the as yet unexploited resource base is very large relative to the amount of incremental depletion occurring in one period. However, the rate of decline in discovery sizes is likely to be greater when firms are close to exhaustion of the resource base. To capture this effect, we define the following index of accumulated exhaustion of the undiscovered resource base as a "depletion" index:

$$\mathrm{DEP} = \left\{ \frac{\text{Estimate of total original oil or gas in place} - \text{Cumulative production to date} - \text{Current estimate of proved resources}}{\text{Estimate of original oil (or natural gas) in place}} \right\}$$

i.e., $DEP_k(t)$ at any point in time t is the index of estimated potential reserves still left in sediments of the k^{th} geological type at time t expressed as a fraction of the total reserves originally in place. δ_k may then be expressed as a function of this index:

$$\delta_k(t) = f(DEP_k(t)) \quad . \tag{19}$$

A reasonable postulate would be

$$\delta_k(t) = c_0 + c_1 DEP_k(t) \tag{20}$$

where c_0 and c_1 are parameters to be estimated.

Finally, each production district might well contain more than one sub-population, and shifts in drilling across populations might occur in response to changes in prices of natural gas or oil. Since the data on size of discoveries are aggregated by production districts, observed average size of discoveries might change in response to price changes because of shifts from one sub-population to another. For instance, if on the average a given price change motivates explorers to increase the proportion of extensive drilling (i.e., drilling in high risk sub-populations which also have larger deposits), the observed average size of discoveries aggregated over all the sub-populations might actually show an increase. The magnitude of such shifts in aggregate average size in response to price changes would be positively related to the amount of new geological knowledge regarding deposits in the district which in turn has been conjectured to be proportional to the number of successful exploratory wells drilled in the region in the recent past. Since the value of δ occurs multiplicatively with the number of successful wells drilled (WXS) in the estimating equations (15) and (17), a natural way to capture the price effects on the aggregated average sizes would be to use the specification $\delta = f(DEP, PG, PO)$. Thus, the estimating equation (17) may be modified to:

$$\log(\bar{s}(t + h)) = \log(\mu(t)) + f(DEP, PG, PO)\,WXS[t, t + h] \qquad (21)$$

where the function f( ) represents the mean decline rate of discovery sizes δ aggregated over an entire production district.

3.2.4. The Success Ratio for Exploratory Wells

The discussion in the previous section is relevant conditional upon an exploratory well striking oil or natural gas. In order to estimate size of find per exploratory well, then, the formulation must be modified to take into account the probability that any well will result in a success. Using postulates I, II and III of Section 3.2.2., it can be shown that once exploration in a sub-population has begun, the probability of a success tends to decrease monotonically throughout the evolution of the play in a pattern similar to that derived for the average discovery size. This leads us to specify a proportional relationship between probability of success SR and discovery size (s). Thus as more exploratory drilling takes place in a given sub-population, we expect to find proportional changes (declines) in average discovery size and success ratio. Once again, to the extent that we are forced to use size and success ratio data aggregated by production district rather than by sub-population, we expect to see some price effects on the mean success ratios reflecting shifts in the relative proportion of extensive and intensive drilling in response to price changes. The success ratio equation should then be

$$\log\left(\frac{\overline{SR}(t)}{\overline{SR}(t_0)}\right) = \log\left(\frac{\bar{s}(t)}{\bar{s}(t_0)}\right) + f_1(PG,PO) \qquad (22)$$

where f_1 ( ) is a function of the current and/or lagged prices of oil and natural gas. The observed price coefficients in the success ratio equations (unlike the average size equations) would also reveal any shifts in directionality in response to changes in the relative prices. For instance, if directionality is strong, a higher oil price might result in an increase in the tendency to "drill for oil" rather than gas, which in turn would increase the fraction of successful oil wells out of total exploratory wells.

We now have all the components for new discoveries of gas and oil. One last point should be made, however. The size of discoveries per exploratory well SW is defined as the product of the success ratio SR and the size of discovery conditional on a success, S, i.e., SW = (SR)(s). It can be shown that under our assumptions,

$$\mathrm{Var}(SW) \approx (\overline{SW})^2 4\sigma^2 \qquad (23)$$

where σ^2 is the variance of the distribution of size per successful well. This relation provides a means of computing the parameters $(RWG)^v$ and $(RWO)^v$ of the exploratory wells equation (12).

In summary, a total of five structural equation forms must be estimated for new discoveries of gas and oil. Equation (12) determines the number of exploratory wells drilled, equation (22) determines the success ratio (estimated separately for oil and gas), and equation (21) determines discovery size per successful well (again estimated separately for oil and gas). The estimation of these equations will be discussed in the next chapter.

3.2.5. Extensions and Revisions

Additions to oil and gas reserves also occur as a result of extensions and revisions of existing fields and pools. Extensions are recoverable reserves that result from changes in the productive limits of known reservoirs. Following the discovery of a reservoir, a producer normally drills additional wells to delineate the productive limits of the reservoir. In doing so, he finds more reserves or less reserves than expected from the discovery well. In general, a substantial portion of extensions are realized within a year or two following the reservoir discovery. This provides the following working hypothesis for the specification of the extensions equation:[10]

$$\text{Extensions} = f_1 \left(\begin{matrix}\text{lagged} \\ \text{discoveries,}\end{matrix} \quad \begin{matrix}\text{lagged exploratory} \\ \text{wells,}\end{matrix} \quad \text{prices, depletion} \right) \tag{24}$$

Revisions are the least predictable category of reserve additions. They refer to changes in oil and natural gas reserve estimates brought about by new information on reservoir characteristics such as porosity, permeability and interstitial water. They result from improved estimates of the size of previously known reservoirs, mostly made without new drilling. We have little economic explanation for the observed size of revisions. Since the total amount of proved reserves at the end of the previous year represents the size of the base susceptible for revision, we expect this to serve as the main variable for explaining revisions. Secondly, information can also arrive from operations in a producing field; lagged incremental production of natural gas (or oil) is therefore included as an explanatory variable. Finally, reserve depletion should have a negative impact on the level of revisions. The specification for the revisions equation is therefore of the form

$$\text{Revisions} = f_2 \left(\begin{matrix}\text{lagged} \\ \text{year-end} \\ \text{reserves,}\end{matrix} \quad \begin{matrix}\text{incremental} \\ \text{production,}\end{matrix} \quad \text{depletion} \right) \tag{25}$$

It is not expected that all of the variables on the right-hand side will figure prominently, but *a priori*, year-end reserves are expected to have a significant effect.

3.3. Structural Equations for Production of Gas

The relationships that specify the level of gas production out of reserves are an important part of the model, since it is a shortage of production in

[10] As the basin is depleted of the richer prospects, it is reasonable to expect the size of extensions to drop. The index of accumulated depletion DEP may therefore be added as an additional explanatory variable on the right hand side. However, it is likely that depletion effects on extensions are already reflected in the functional relationship of (24) through its effects on discoveries and exploratory wells. This is a matter to be resolved on the basis of empirical evidence from econometric estimation. Similarly, an argument may be made to include the price of natural gas (or oil) as an additional explanatory variable on the grounds that incentive to gain more extensions is influenced by price expectations. This too must be resolved empirically.

wholesale transactions that affects government pricing policies in field transactions. We saw in the 1960's a general condition of depletion of the base of proven reserves, as reserve-to-production ratios fell from 20 at the beginning of the decade to about 12 at the end of the decade. Sufficient production with falling R/P ratios cannot be had indefinitely; at some point the amount of reserves available to back production is "insufficient", in the sense that a gap is opened between the demand for production and the supply that can be produced. The extent to which that gap occurs depends on the characteristics of the relationships between prices, reserves and production.

The characteristics of production will depend on the extent of competition among natural gas producers. In general we might consider three alternative hypotheses that could apply to the structure of the natural gas industry:

(I) The industry is competitive (at the production level) so that the supply price is simply the marginal cost of developing existing reserves to achieve a particular rate of annual production.

(II) The industry is non-competitive, but whatever degree of monopoly power individual firms have in the absence of regulation has been stripped away by regulation. This would imply that the regulated ceiling price is at or below the competitive price, so that marginal cost pricing again applies.[11]

(III) The industry is non-competitive, and existing regulation is not sufficient to strip away all monopoly power. This would imply that the regulated price is greater than marginal costs.

If the regulatory agency forced the company to lower its price below the "competitive price", the quantity produced would decrease and would be determined by marginal costs.

---

[11] Some elaboration may be in order for the second hypothesis. Suppose that only a single company, a monopolist, discovered and produced all of the gas in some region of the country, and that because of regulation the company were forced to lower its price from the profit-maximizing equilibrium level. The quantity produced would then increase. As the ceiling price were lowered the quantity produced would continue to increase until the point at which the average revenue and marginal cost curves intersected. That price could be termed the "competitive price", and the corresponding quantity the "competitive quantity", because at that point the monopoly has effectively been stripped of all of its monopoly power, and behaves as though it were broken up into a set of identical, competitive, unregulated firms.

The structural equations based on the first two hypotheses are much the same, since both imply marginal cost pricing. Let us therefore examine the characteristics of marginal costs, and use those characteristics to construct some alternative specifications for a production equation. Then we will modify those specifications to account for deviations from marginal cost pricing in a way that will allow for a structural specification based on the third hypothesis.

The marginal costs for a production level q out of proved reserves R depend upon the decline rate, discount rate, and other parameters. Assuming a constant decline rate, a, in percent per year of production out of reserves,

$$a = q/R = 1/\text{reserve-production ratio,} \tag{26}$$

we can write the proved reserve level as

$$R = q \int_0^\infty e^{-at}\, dt = q/a. \tag{27}$$

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

$$PME = q \int_0^\infty e^{-(a+\delta)t}\, dt = q/(a + \delta). \tag{28}$$

The next step in arriving at a marginal cost function is to specify a functional form for the amount of development investment, I, needed to obtain the constant production level q. Unfortunately, little theory exists on which to base this specification, so that we must consider one or more functional forms that follow intuitive reasoning about the behavior of investment costs, and then test those functional forms by fitting them to data. We will consider the following development investment function:

$$I = A + ce^{\beta a}q, \tag{29}$$

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 much larger than 10), I will be roughly linear in q, but when a becomes larger (e.g., the reserve-production ratio approaches 5), exponential increases in costs at the margin predominate.

The marginal development cost (MDC) is given by:

$$MDC = \frac{dI}{d(PME)} = \frac{dI}{dq} \cdot \frac{dq}{d(PME)}$$

$$= \left(\frac{\partial I}{\partial a}\frac{da}{dq} + \frac{\partial I}{\partial q}\right) \cdot \frac{dq}{d(PME)} \quad . \tag{30}$$

Now we can substitute equation (29) for I into the right-hand side of equation (30) to yield the marginal development cost function:

$$MDC = \left(\frac{c\beta}{R} e^{\beta a} q + c e^{\beta a}\right) \cdot \frac{(a + \delta)^2}{\delta}$$

$$= (\beta a + 1)\ c e^{\beta a} \frac{(a + \delta)^2}{\delta}$$

$$= (\beta a + 1)\ c\delta e^{\beta a} \left(1 + \frac{a}{\delta}\right)^2 \quad . \tag{31}$$

During the 1970's we can expect reserve-to-production ratios no greater than 10, so that "a" should be at most 0.1. A reasonable value for the discount rate is also 0.1, so that the above marginal cost function could be close to:

$$MDC \cong 4(\beta a + 1)\ c\delta e^{\beta a} \cong \alpha_0 e^{\beta a} \tag{32}$$

Aside from its fit to recent data, this formulation is appropriate because it has implications for production under conditions of declining reserve-production ratios. To analyze such conditions, we will in fact consider two exponential approximations to equation (32):

$$MDC_{t,j} = \alpha_0 e^{\alpha_1 q_{t,j}/R_{t,j}} \tag{33}$$

and

$$MDC_{t,j} = \alpha_0 e^{\alpha_1 q_{t,j} - \alpha_2 R_{t,j}} \tag{34}$$

Setting the wellhead price of gas $PG_{t,j}$ at time t in region j equal to the marginal development cost,[12] and taking the logs of both sides of (33) and (34) results in the structural equations:

$$q_{t,j} = \alpha_0' R_{t,j} + \alpha_1' R_{t,j} \log PG_{t,j} \tag{35}$$

and
$$q_{t,j} = \alpha_0' + \alpha_1' \log PG_{t,j} + \alpha_2' R_{t,j} \quad . \tag{36}$$

Let us now go back and consider an alternative investment function which also has "reasonable" characteristics:

$$I = A + ce^{(a-\delta)/\delta} \quad , \tag{37}$$

This investment function is also exponential, but it is more flat in the range of $a < \delta$. Now for this function marginal cost is given by:

$$MDC = ce^{(a-\delta)/\delta}(a + \delta)^2/\delta^2 R \quad . \tag{38}$$

Again, setting price equal to marginal cost and assuming that $a \approx \delta \approx 0.1$, we have

$$PG_{t,j} \cong \frac{\alpha_0}{R} e^{(a-\delta)/\delta} \quad . \tag{39}$$

After taking logs of both sides, we then have

$$q_{t,j} = \alpha_0' R_{t,j} + \delta R_{t,j} \log R_{t,j} + \delta R_{t,j} \log PG_{t,j} \quad . \tag{40}$$

---

[12] Under the first two hypotheses price is set equal to marginal development costs in present-Mcf-equivalents. Assuming all present and future production costs to be included in I, and the competitive price constant over time, the discounted sum of all present and future profits is given by P•(PME) - I, which when maximized, yields P = dI/d(PME).

Assuming that δ is a parameter to be estimated (and expecting its estimated value to be close to 0.1), we would estimate the structural equation:

$$q_{t,j} = \alpha_0'R_{t,j} + \delta\, R_{t,j}\, \log\, (R_{t,j}PG_{t,j}) \quad . \tag{41}$$

All of the formulations described above assume that either of the hypotheses (I) or (II) hold, or that regulated prices are equal to marginal costs. It is straightforward to modify these formulations to account for deviations from marginal cost pricing and thus provide a means for testing hypothesis (III). Setting marginal revenue equal to marginal development cost we have

$$P_j(1 + 1/n_je_j) = MDC \tag{42}$$

where n_j is the number of equivalent equal-sized firms in region j, and e_j is the market elasticity of demand in region j.[13]

The alternative estimating equations (35), (36), and (41) can now be rewritten to include this term that accounts for varying degrees of competition in different regions:

$$q_{t,j} = \alpha_0'R_{t,j} + \alpha_1'R_{t,j}\, \log\, PG_{t,j} + \alpha_2\, \log\, (1 + 1/n_je_j) \tag{43}$$

$$q_{t,j} = \alpha_0' + \alpha_1'\, \log\, PG_{t,j} + \alpha_2'R_{t,j} + \alpha_3\, \log\, (1 + 1/n_je_j) \tag{44}$$

$$q_{t,j} = \alpha_0'R_{t,j} + \delta\, R_{t,j}\, \log\, (R_{t,j}PG_{t,j}) + \alpha_1\, \log\, (1 + 1/n_je_j)\, . \tag{45}$$

Since the number of firms is different in different production regions, we would expect the last term in each of the above equations to be statistically significant when the equations are estimated. If this term is not

---

[13] This formulation, consistent with both the Bain and the earlier Cournot analysis, is probably the most general model of imperfect competition subject to estimation by a regression equation. See W.S. Vickrey, Microstatics, Harcourt, Brace & World, 1964, pp. 337-339.

significant that would cast some doubt on the validity of hypothesis (III), and lead us to believe that marginal cost pricing indeed applies to the production of gas out of reserves.

In summary, a total of six structural equation forms can be estimated for gas production. Equations (35), (36), and (41) represent marginal cost pricing (hypotheses I and II) for alternative investment cost formulations; equations (43), (44), and (45) are the analogous forms that account for deviations from marginal cost pricing (hypothesis III). We will test the fit of all of these equations in the next chapter.

3.4. Equations for Reserves and Production of Offshore Gas[14]

The discovery and production of natural gas in offshore regions is a particularly important part of the econometric policy model. There are now, for geological and economic reasons, high probabilities of finding large discoveries offshore. As both gas and oil prices increase and more offshore acreage is leased by the Federal Government, these regions will probably provide an increasing share of gas production.

There are a number of theoretical reasons for including separate structural equations for offshore reserves and production in the model. Reserve accumulation and production take place under somewhat different engineering and economic conditions from those onshore. For example, almost all drilling offshore is extensive in nature, while onshore tracts may be explored on either the intensive or extensive margins. Also, drilling costs are much higher offshore (thus limiting offshore drilling largely to major petroleum companies), and offshore leasing procedures of the Federal Government do not apply to privately-owned onshore land (resulting in checkered patterns of drilled

[14]This section, as well as section 4.5, are based on Philip N. Sussman, "Supply and Production of Offshore Gas Under Alternative Leasing Policies", unpublished Master's thesis, Sloan School of Management, M.I.T., June, 1974.

acreage offshore.[15]

There are also empirical reasons for constructing a separate model for the offshore region. Different data are available on offshore drilling activities. There is only very limited data available on gas and oil success ratios offshore, so that the offshore discovery process must be modeled without direct estimation of success ratios. On the other hand, there are political limitations on acreage leasing offshore, so that acreage availability is an additional source of explanation of offshore drilling activity.

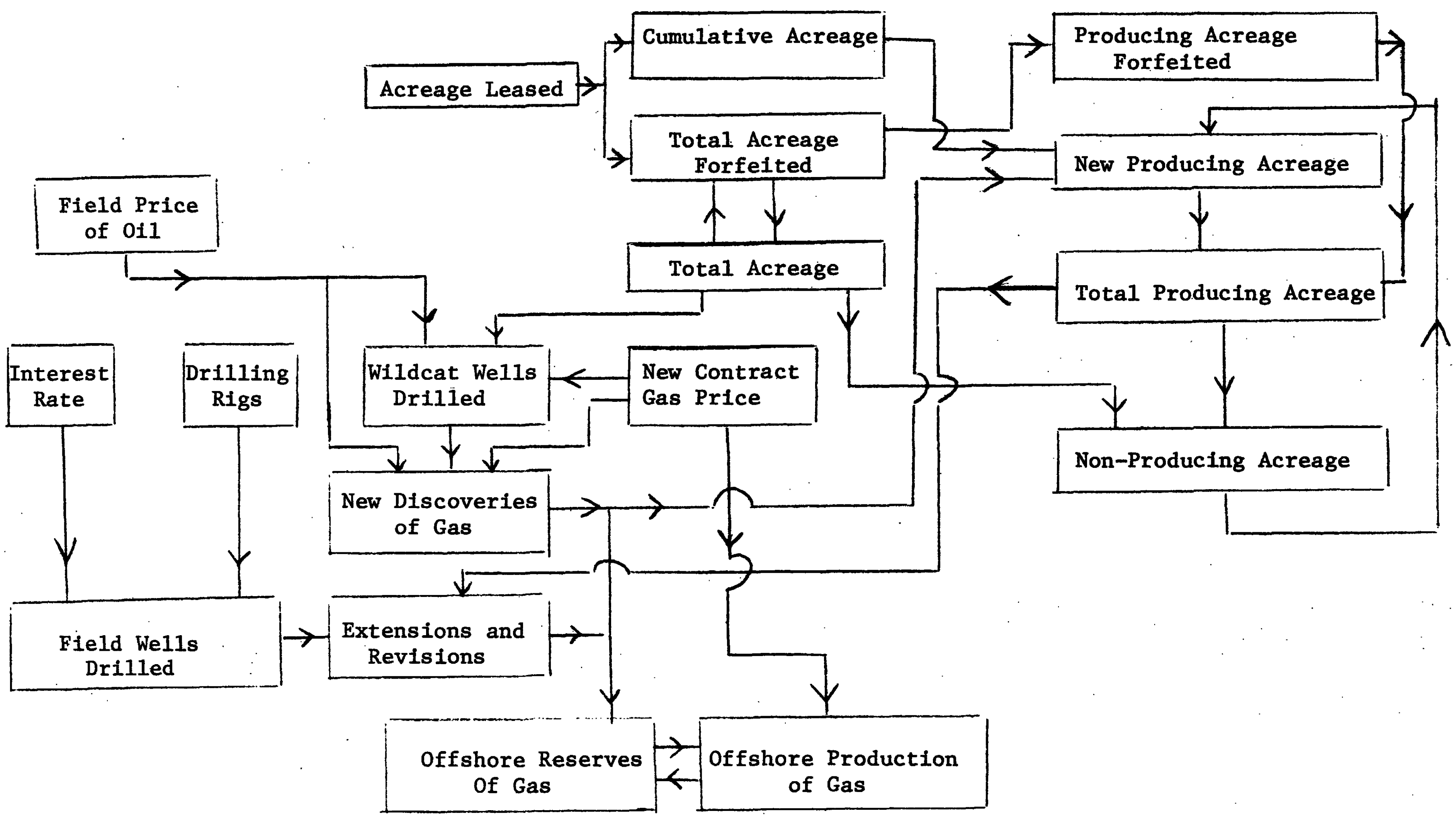
The model here describes relationships between reserves and production of gas off the coast of Louisiana and such policy variables as the new contract field price of gas and the amount of acreage leased annually.[16] Important exogenous variables are interest rates, the price of oil, and the number of drilling rigs operating offshore. The model is shown schematically in Figure 3.3, and operates as essentially three interacting blocks that determine respectively (1) total acreage, (2) producing acreage and (3) reserve additions and production.

It is the practice of the Interior Department's Bureau of Land Management to hold periodic auctions of acreage to be explored for oil and gas. Total acreage leased by the Federal Government is by definition last year's total acreage plus acreage leased this year minus acreage forfeited this year. Forfeited acreage is primarily acreage leased five years ago on which producible quantities of oil or gas were not found. Total acreage is an

[15]The Bureau of Land Management decides to accept bids for offshore tracts based on a variety of considerations, including the degree of true bidding competition, environmental consequences, etc. Once a tract is leased, however, the discovery of producible quantities of oil or gas must occur within five years or else the lease is forfeited. This regulation encourages early exploration of leased tracts and leads to discoveries relatively soon after the lease sale.

[16]The model pertains to Offshore Louisiana rather than the entire Offshore Gulf of Mexico because data on reserve additions were not available for Offshore Texas. One would expect, however, that the structural equations are valid for other offshore Gulf of Mexico regions as well.

Figure 3.3 Block Diagram of the Offshore Model



important variable because it is a determinant of well drilling activity. Without lease rights, no wells can be drilled at promising locations. Cumulative acres leased, which is the total number of acres leased by the Bureau of Land Management since 1954, also appears as a variable in the model, and is one of the determinants of new producing acreage.

The second block in the model determines the amount of producing acreage, and it contains only definitional equations. Producing acreage this year is equal to producing acreage last year plus new producing acreage minus producing acreage forfeited. The producing acreage forfeited is acreage that was producing in the previous year, but is now nonproducing and is dropped from the leasing program. Non-producing acreage is equal to total acreage minus producing acreage.

The third block of equations, which is behavioral, determines reserve additions and production from reserves. Reserve additions contain two components: new discoveries, and extensions plus revisions.[17] The discovery process begins with the number of exploratory wells drilled, which is determined by an index of gas and oil field prices together with total acreage.[18] The average discovery size per well drilled (whether the well is successful or unsuccessful) is determined by a second index of gas and oil prices, as well as the cumulative number of wells drilled (this last variable serving to indicate a depletion effect in the model). New discoveries are determined by the product of wells drilled and size of discovery per well.

The theoretical arguments that led to the specification of our onshore

---

[17] Because of data limitations, offshore extensions and revisions could not be modeled separately from each other, as was the case onshore.

[18] Because of data limitations, we include in offshore exploratory wells only <u>wildcat wells</u>, which are wells drilled in areas that have not yet been shown to contain gas or oil. Our onshore equations use a broader class of exploratory wells, including those used to search for extensions of known fields.

reserves equations cannot be extended completely to offshore. One reason for this is that we cannot estimate a success ratio equation offshore. Another reason has to do with particular geological conditions. Offshore drilling costs rise considerable as the water depth increases.[19] This is important because the acreage leased each year has been at progressively greater depths, so that in a given year with constant prices one would expect a smaller increase in the number of wildcat wells drilled per new acre than in the previous year. In order to embody these conditions, the following specifications are used for well drilling and discoveries per well:

$$WWT = b_0 + b_1 \log ACT + b_2 \log P_{og} \tag{46}$$

and

$$\frac{DG}{WWT} = c_0 + c_1 \log CWWT + c_2 \log P_{og} \quad . \tag{47}$$

Here DG is new discoveries, WWT is the number of wildcat wells drilled, ACT is total acreage, CWWT is the cumulative number of wildcat wells drilled, and P_{og} is a combined price index of oil and gas.

The quantity of new reserves added by extensions and revisions (XRG) will also depend on well drilling, but here the relevant variable is field (development) wells rather than wildcat wells.[20] Extensions and revisions will be taken to be a linear function of the number of field wells drilled (FWT) and the

---

[19] For example, the cost of exploratory drilling on a lease 600 feet under water is 2-1/2 times that at 100 feet and at 1000 feet it is 4 times that at 100 feet. The cost of development well drilling at 600 feet is 1-1/2 times that at 100 feet, but at 1000 feet it is 8 times that at 100 feet.

[20] Different well data is available offshore than onshore. Only exploratory well data is available on shore, which is why our onshore extensions and revisions equations do not contain field wells as an explanatory variable.

number of producing acres in the previous year (ACP):

$$XRG = f(FWT, ACP_{-1}) \; . \tag{48}$$

The number of offshore field wells drilled is determined endogenously in the model as a function of the number of offshore drilling rigs (DRO) and the interest rate (INT). Drilling rig availability places a capacity constraint on field well drilling, and the interest rate reflects capital costs.

$$FWT = f(DRO, INT) \; . \tag{49}$$

Total offshore reserves can now be determined. They are equal to last year's reserves, plus new discoveries (equal to (46) times (47)), plus extensions and revisions, minus current production.

Production of gas out of reserves follows the same formulation as for onshore, so that equations (35), (36) and (41) above would apply. The offshore production equation will differ in one respect, however, in that total reserves should appear in the equation with a longer lag than is the case onshore. The reason for this is that development costs are much more extended over time offshore because the construction of offshore pipeline systems precedent to production requires not only extensive regulatory review before construction, but in many cases the completion of discovery activities in a large block of leases.

Two more behavioral relationships are needed in the offshore model, and these explain forfeited acreage and new producing acreage. Forfeited acreage (ACRD) is explained as a function of the amount of acreage leased (ACR) five years previously and an average of the total acreage (ACT) five and six years previously:

$$ACRD = f[ACR_{-5}, (ACT_{-5} + ACT_{-6})/2] \; . \tag{50}$$

New producing acreage (ACPN) is explained by nonproducing acreage (ACN) one and two years previously, the amount of new discoveries (DG) in the previous year, and the cumulative number of acres leased since 1954 (CACR):

$$ACPN = f(ACN_{-1}, ACN_{-2}, DG_{-1}, CACR) \quad . \tag{51}$$

The offshore model thus contains a total of twelve equations, of which seven are behavioral (wildcat wells, discoveries, extensions and revisions, field wells, production, forfeited acreage, and new producing acreage) and five are identities (total acreage, producing acreage forfeited, producing acreage, nonproducing acreage, and total reserves). Although the offshore model contains less of a theoretical basis for describing reserves than is the case onshore, it explains in some detail the process by which lands are leased and become available for exploration and ultimately gas production. This makes it possible to use the overall gas model to study the effects of changes in acreage leasing policies by the Federal Government. Such policies may play an important role in determining natural gas availabilities over the coming years.

3.5. Pipeline Price Markup Equations

Pipeline companies purchase gas from producers and sell it to other pipeline companies, to industrial consumers, and to retail gas utility companies for delivery to final industrial, residential, and commercial consumers. The pipelines buy gas at the field price and then add a markup based in part on the transportation costs from production to consumption regions. The wholesale prices of gas paid by buyers from each pipeline are simply equal to the average field price paid by that pipeline plus the various markups charged by that pipeline.

In modeling the price markup we must consider those variables which directly or indirectly determine the cost of transporting gas. One would expect that the most important explanatory variable in determining the size of the price markup is the distance over which the gas is transported; the greater the distance between producer and consumer, the greater the transport costs and thus the larger the markup. There are, however, economies of scale involved in the transportation of gas, so that the cost per mile per Mcf decreases as the volumetric flow through the pipeline increases. Thus we would expect that some measure of volumetric capacity in the pipeline system would also be an important explanatory variable in determining the markup, and we would expect to find that, other things being equal, pipelines with larger volumetric capacities would charge smaller price markups.

Other economic variables should affect the size of the markup. The level of total pipeline sales should be another determinant of economies of scale, and as the level of total sales increases we would expect a decrease in the size of all markups. It is also important to include some variable that reflects the capital costs of the pipeline. We use the interest rate as a variable to reflect capital costs, and expect the interest rate to be positively correlated with the markup.

Finally, we would expect that as the amount of competition between pipeline companies increases, the size of the markup would decrease. The markup equations should include an index of the degree of competition as an independent variable; here we use the Herfindahl index

$$H_j = \sum_{i=1}^{N} x_{ij}^2 \tag{52}$$

where H_j is the index for the jth consuming region, x_{ij} is the fraction of gas consumed in region j provided by company i, and N is the number of firms operating in the jth consuming region.[21]

The general form of the pipeline price markup equation is thus

$$PGW_{j,t} - \overline{PG}_{j,t} = f(M_{j,t}, V_{j,t}, SALES_{j,t}, INT_t, H_j) \, . \qquad (53)$$

Here PGW is the wholesale price of gas, $\overline{PG}$ is the average wellhead price (on both old and new gas), M is the average mileage between producing and consuming regions, V is volumetric capacity, INT is the interest rate, SALES reflects average annual sales, and H is the Herfindahl index described above.

---

[21]Since

$$\sum_{i=1}^{N} x_{ij} = 1$$

the Herfindahl index will always lie between 0 and 1. A value of 1 usually is taken to indicate monopoly and a value of 0 to indicate perfect competition, but such values are not definitive.

3.6. Structural Equations for Wholesale Demand for Natural Gas and Fuel Oil

In this model wholesale demand for natural gas is disaggregated both by region and by type of user. This is necessary because the buyers of gas differ from region to region, and among themselves in each region. Price elasticities of demand differ across regions, as do the determinants of the long-run growth in demand (as a result of different degrees of industrialization, differences in housing, etc.). Also price elasticities and the determinants of the growth of demand are expected to differ between residential and industrial classes of consumers.[22]

The wholesale demand for fuel oil is modeled in the same regional "markets" as wholesale natural gas demand. Since fuel oil is not transported across the country through a fixed pipeline network, the markets in which it is sold are not the same as those for natural gas. On the other hand, fuel oil and natural gas are competitive with each other both in industrial and residential/ commercial markets, and when analyzing the impact of natural gas regulatory

[22] One might argue that industrial demand for gas should be further disaggregated, since there are three broad uses of natural gas by industry, and for each use the quality required of the gas (and thus the price paid) is somewhat different. Gas used for chemical processes must be of extremely pure quality and may be sufficiently unique to that process that there are few substitutes. A second use for industrial gas is for boiler fuel, and here the gas need not be very pure and competes with oil and coal. The third (and smallest) use of industrial gas is for electricity generation and transportation, and here too, the quality of the gas need not be very high (so that there is substitutability), since this is again for boiler use. Contracts for industrial gas are also made on either a "firm" or an "interruptible" basis. Firm contracts require that gas be supplied throughout the year at a more or less constant flow rate, while interruptible gas may be supplied only in the off-peak season when there is excess capacity. In this model all industrial gas sales are aggregated together. One reason for this is that it is difficult to obtain data on industrial gas sales broken down by use or by quality; pipeline companies must report to the FPC gas sales to each industrial firm, but they do not report the ultimate use or quality of the gas sold. Similarly, it is difficult to separate "interruptible" from "firm" sales, particularly since the proportions of each purchased even by individual companies will change over the year, so that data series disaggregated in this way will necessarily be quite noisy.

policies, it is desirable to be able to determine how changes in gas demand are related to changes in oil demand. Thus, in constructing fuel oil demand equations we use the same regional breakdowns as for natural gas demand. Fuel oil demand is also disaggregated into residential/commercial demand (for Nos. 2 and 4 oil) and industrial demand (for No. 6 residual oil).

3.6.1. The "New" Demand for Natural Gas

Our objective is to construct demand equations that relate, for each wholesale market region, the quantity of natural gas demanded to the wholesale price, the price of alternative fuels, and "market size" variables such as population, income, and investment, which determine the number of potential consumers. In all of our equations, rather than explain the level of total demand, we use as the dependent variable the level of additional or "new" demand, which we denote by δQ.

In the short run, as Balestra has shown in his classic study of residential gas demand [8], the level of total demand should be relatively price inelastic and would simply depend on the total stock of gas-burning appliances in residential and industrial use. New demand, however, should respond to the price of gas and to the price of competing fuels; decisions to buy new appliances are affected by fuel prices. The new demand for gas, δQ, is made up of the increment in total gas deliveries $\Delta Q = Q_t - Q_{t-1}$, plus the replacement of run-out agreements with old buyers so as to allow for continuation of old deliveries. To find replacement, total wholesale gas demand could be considered to be a function of the stock of gas-burning appliances, A:

$$Q_t = \lambda A_t,$$

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

$$\delta Q_t = \Delta Q_t + r\lambda A_{t-1} \quad . \tag{55}$$

Now substituting (54) into (55) gives

$$\delta Q_t = \Delta Q_t + rQ_{t-1} \tag{56}$$

so that 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. It is this new demand that Balestra has shown to be sensitive to the price of gas, as well as to the prices of competitive fuels such as oil.

Our a priori assumption on causal factors is somewhat more general than Balestra's. It is posited that new wholesale demand depends on wholesale gas and oil prices as well as total income and population (operating through purchases of new appliances by final consumers). But it is also posited that the level of total demand is itself a function of income and population, so that new demand is also a function of "new" income δY and "new" population δN:

$$\delta Y_t = \Delta Y_t + rY_{t-1} \tag{57}$$

$$\delta N_t = \Delta N_t + rN_{t-1} \tag{58}$$

where r is the same depreciation rate described above. Thus an equation for residential/commercial gas demand (TRCS) should have the general form:

$$\delta TRCS_{t,j} = f(PGW_{t,j}, PFOIL_{t,j}, Y_{t,j}, N_{t,j}, \delta Y_{t,j}, \delta N_{t,j}) \tag{59}$$

where $PGW_{t,j}$ is the wholesale price of gas in region j at time t, $PFOIL_{t,j}$ is the average wholesale distillate oil price in the region, Y is disposable personal income, and N the population by state.

We would expect that our industrial demand equations should be similar in form to those for residential/commercial demand. The prices of gas and oil at wholesale are determinants of "new" demand, as are capital expenditures by industry K (although with some lag, since capital expenditures "gestate" into additions to the stock of working capital only after some time). The level of total industrial demand should also be related to overall industrial activity. The equation for industrial demand (TINS), then, has the form:

$$\delta TINS_{t,j} = f(PGW_{t,j}, POIL_{t,j}, \delta VAM_{t,j}, K_{t,j}) \tag{60}$$

where value added in manufacturing (VAM) is a measure of industrial activity in state j. When actually estimating equations (59) and (60) we follow Balestra and specify linear relationships. There is no specific theoretical motivation for linear demand equations, and an alternative specification, which has some theoretical justification, is discussed in the Appendix to this chapter.

3.6.2. Wholesale Demand for Fuel Oil

The equations describing the wholesale demand for fuel oil are similar in form to those described above for natural gas. We relate the quantity of fuel oil demanded to the wholesale price of oil, the price of alternative fuels (in this case natural gas), and "market size" variables including population, income, and capital investment.

As was the case for natural gas, we use as the dependent variable the level of "new" demand rather than the level of total demand. Thus our oil demand equations resemble equations (59) and (60). Residential/commercial demand for oil (QO2) has the form:

$$\delta QO2_{t,j} = f(PFOIL_{t,j}, PGW_{t,j}, Y_{t,j}, N_{t,j}, \delta Y_{t,j}, \delta N_{t,j}) \tag{61}$$

and the equation for industrial demand (RSID) has the form:

$$\delta RSID_{t,j} = f(POIL_{t,j}, PGW_{t,j}, \delta VAM_{t,j}, K_{t,j}) \quad . \tag{62}$$

Again, when actually estimating regression equations for (61) and (62) we will specify linear relationships.[23]

3.7. Connecting Supply Regions with Demand Regions

To complete the specification of the model it is necessary to describe how gas flows from producing regions to points of final consumption. The interregional flows are important because they permit use of the model for policy analysis and forecasting on a regional basis. In particular, in a situation of excess demand, the flow table enables us to calculate the size of the excess demand in each consuming region, as well as the amount of "underproduction" in each production district.

Here we designate a matrix for the interchange of gas supplies from eight large production regions by the pipeline network with five demand areas of the U.S. The interregional input-output matrix shows both the fraction of each producing region's gas that goes to each demand area (g_{ij}) and the fraction of each demand area's gas that comes from each producing region (f_{ij}). The construction of this matrix is made necessary by the fact that the average price of gas in each state within a demand region is

[23] Note that the appliance depreciation rate used to calculate new demand may be different for oil than for gas. In fact, when these depreciation rates were estimated, the value for oil appliances was found to be 0.10, while for gas appliances it was 0.07. This will be discussed further in the next chapter.

dependent on both the wellhead prices and the quantities delivered from each production region. Once the matrix has been constructed, i.e., once g_{ij} and f_{ij} have been calculated, it then becomes possible to calculate an "average wellhead price" of gas delivered to each state, $\overline{PG}_i = \sum_j PG_j f_{ij}$ where $\overline{PG}_i$ is the average wellhead price of gas (before a pipeline markup) delivered to demand region i, PG_j is the wellhead price of gas in production district j, and f_{ij} is the fraction of demand region i's consumption that is supplied by production region j. The difference between the actual wholesale price in the region and the average wellhead price is simply the price markup charged to buyers in that particular demand region.

The input-output matrix enables the calculation of excess demand on a regional basis. The average wholesale price of gas in each state determines demand in the state, while the amount of gas actually provided is determined by adding the fractions of each production district's output going into that state (with the fractions again determined from the input-output matrix). The difference between demand and supply thus calculated is excess demand:

$$ED_i = D_i - \sum_k g_{ik} Q_k \tag{63}$$

where ED_i is the excess demand in region i, D_i is the demand in region i, Q_k is the production of supply district k, and g_{ik} is the fraction of k's production going to demand region i. The production shortage in region k can be likewise calculated from $PS_k = Q_k - \sum_j f_{jk} D_j$.[24]

---

[24] One might ask whether it is reasonable to expect the input-output coefficients f_{ij} and g_{ij} to remain constant over time. In the next chapter we will see how these coefficients are calculated, and we will in fact find that they have changed somewhat over the period 1966 to 1971. The question, however, is whether these changes are largely random or are instead the result of a feedback mechanism in the pipeline network system that alters the distribution of gas in response to excess demands or price differentials across regions. An attempt was made to empirically model price-dependent time-varying input-output coefficients, but the data failed to support the thesis that this feedback mechanism has been the cause of coefficient fluctuations. This result, together with the fact that coefficient fluctuations have been relatively small, led us to use a static framework for modeling interstate flows of gas. This will be discussed further when we examine the empirical results in the next chapter.

Special relationships must be established for intrastate flows of gas. Because of the large differences between the wellhead prices of interstate gas under FPC regulatory policy and intrastate prices not under regulation, some production districts have experienced large changes in the relative volumes of interstate and intrastate gas. It is important that future changes in interstate/intrastate allocations that occur because of the difference between interstate and intrastate prices be properly accounted for in the model. Therefore, the static interregional flow matrix is altered to allow for price-dependent changes in the amount of gas delivered for transmission to interstate pipeline companies in the gas producing states. If we assume that proportional price increases for both interstate and intrastate gas will not affect percentage allocations, then the allocation mechanism can be modeled simply as

$$PCT = f(P_{in}/P_{out}) \tag{64}$$

where PCT is the fraction of gas production allocated to intrastate sales, P_{in} is the average intrastate wellhead price, and P_{out} is the average interstate wellhead price. An equation of the form of (64) will be estimated and used when the model is simulated to distribute gas between inter- and intrastate markets. Interstate gas can then be distributed via the static input-output matrix.[25]

---

[25] We are modeling the pipeline network as it is, and not as we believe it should be. Ideally gas should be distributed according to an optimal feedback mechanism that prevents large excess demands from occurring in some whoelsale regions while other regions experience market clearing at low prices. An optimizing pipeline network model using mathematical programming is currently being constructed as part of a Ph.D. dissertation at M.I.T.

3.8. Summary of the Structural Model

There are, in addition to the input-output matrix, a total of 22 structural equations that are behavioral in nature (i.e., that must be estimated), and these are summarized in Table 3.1. Note that alternative structural forms have been specified for some of the equations, and the choice of one form over another must await econometric testing. Other structural equations (e.g., onshore reserve equations) must be modified before they can be fitted to data, due to statistical considerations that will be discussed in the next chapter. Finally, some equations contain explanatory variables, price indices, or parameters that must themselves be estimated from structural specifications; these too are largely statistical problems. The "specification" of the model as a whole has therefore been completed only insofar as one or more structural forms have been designated for each of the model's components.

There is a good deal of variability in the degree to which these equations of the model are theoretically based. We have presented strong theoretical arguments for the onshore reserve equations and for production out of reserves. The price markup and wholesale gas and oil demand equations have less theoretical justification, and the offshore acreage and reserves equations could be considered "black box" representations. It is our hope, however, that those parts of the model that tend towards "black box" at least meet the basic test of being intuitively plausible.

In the next chapter we carry through the estimation of the model, in a fashion that fills in the details of model specification. This involves choosing among alternative equation forms, selecting particular exogenous explanatory variables, and determining the exact lag structure for each equation.

Table 3.1

The Structural Equations

Block	Variable(s) Explained	Number of Equations	Equation Numbers in Text
Reserves (onshore)	Exploratory Wells (WXT)	1	(12)
	Size of Discovery, gas and oil (SZG, SZO)	2	(21)
	Success Ratio, gas and oil (SRG, SRO)	2	(22)
	Extensions, gas and oil (XG, XO)	2	(24)
	Revisions, gas and oil (RG, RO)	2	(25)
Production (onshore)	Production Out of Reserves (QG)	1	(35), (36), (41), (43), (44), (45)
Offshore Model	Acreage, Reserves, Production (WWT, DG, XRG, FWT, QG, ACRD, ACPN)	7	(46), (47), (48), (49), (36), (50), (51)
Price Markup	Wholesale Gas Price (PGW)	1	(53)
Wholesale Gas Demand	Residential/Commercial Demand (TRCS), Industrial Demand (TINS)	2	(59), (60),
Wholesale Oil Demand	Residential/Commercial Demand (QO2), Industrial Demand (RSID)	2	(61), (62)
Interregional Flows	Input-Output Matrix		

APPENDIX:

WHOLESALE DEMAND FOR GAS BY A REGULATED UTILITY

A large proportion of wholesale gas purchases are made by public utility companies that operate under a regulatory constraint, and we would expect that this constraint would affect not only the retail pricing policies of the utility companies but also the characteristics of their demands to buy gas from pipeline companies at wholesale. Let us therefore examine the behavior of a profit-maximizing gas utility under a regulatory constraint, assuming that the utility is a competitive buyer of gas from the pipeline (i.e. it has no monopsony power), and that it re-sells all of the gas that it buys to residential and commercial buyers.
The utility's behavior will depend on the demand functions of final buyers, so that by positing alternative retail demand formulations we can derive alternative models for wholesale gas demand by the utility.

In the analysis that follows we use the following notation:

Q_g = quantity of gas sold at retail by the utility

Q_w = quantity of gas bought at wholesale by the utility

P_g = retail price of gas

P_w = wholesale price of gas

K = capital stock of utility

i = interest rate

s = allowed rate of return under regulation (assume that $s \cdot i$)

m = marginal revenue of retail sales = $\frac{\partial}{\partial Q_g}(P_g Q_g)$.

We assume that the utility has only two major costs--the cost of capital (rK) and the cost of the gas which it buys from the pipeline ($P_w Q_w$).

Assuming also that the amount of capital needed by the utility (in the form of storage tanks, pumps, underground pipes, etc.) is given by the relation:

$$K = \gamma_1 Q_g^{\gamma_2} \tag{A1}$$

with K taken as a long-run capital requirement, and with increasing returns to scale so that $0 < \gamma_2 < 1$. Finally, since over the long-run whatever goes into the utility at wholesale must come out at retail,[26] we have that $Q_g = Q_w$. Thus the utility's profit

$$\pi = P_g Q_g - r\gamma_1 Q_g^{\gamma_2} - P_w Q_g \tag{A2}$$

is maximized subject to the regulatory constraint

$$P_g Q_g - P_w Q_g \leq Ks \quad . \tag{A3}$$

The first-order conditions for the constrained maximum include

$$P_w = m - \frac{r-\lambda s}{1-\lambda} \gamma_1 \gamma_2 Q_g^{\gamma_2 - 1} \tag{A4}$$

and

$$P_w = P_g - \gamma_1 Q_g^{\gamma_2 - 1} s \quad . \tag{A5}$$

Here m is the marginal revenue of retail sales, i.e.

$$m = P_g + Q_g \frac{\partial P_g}{\partial Q_g} \quad . \tag{A6}$$

When regulation is effective (i.e. when the allowed rate of return s is smaller the rate of return which the company would otherwise obtain) equation (A5) determines the wholesale demand function in terms of the retail

[26] This is not exactly true, since the utility adds some manufactured gas to the natural gas that it buys at wholesale in order to give it an odor.

demand function, and this can be substituted into equation (A4) to determine λ, the marginal profit that occurs when the regulatory constraint is relaxed. When regulation is not effective (i.e. s is higher than any rate of return that the utility can obtain), λ is equal to zero, and equation (A4) determines the wholesale demand function, again in terms of the retail demand function.

In the general case equation (A5) determines the demand for gas at wholesale assuming that regulation is binding.[27] Unfortunately the allowed rate of returns will be different for different utilities, so that this equation may be difficult to estimate. If we assume that λ is more stable across utilities, and that

$$\lambda s \ll r,$$

then equation (A4) can be estimated directly to determine wholesale demand. The problem here is that the marginal revenue at retail, m, may (depending on the retail demand function) have a form that is itself difficult to estimate. Let us study this in the context of two alternative retail demand formulations.

A.1. Linear Expenditure System for Retail Demand

We could begin by modeling residential and commercial retail demand for natural gas as part of a linear expenditure system.[28] Writing the system in its static form, we have the utility function

$$u = \sum_{i=1}^{n} \beta_i \log (q_i - b_i) \quad . \tag{A7}$$

[27] Note that our utility does not behave according to the standard model of the regulated firm. There is no Averch-Johnson effect, for example, because there is no capital-labor (or capital-fuel) substitution -- the two inputs, capital and fuel, have a fixed relationship to each other. Thus factor demands are determined entirely by the regulatory constraint (as long as that constraint is binding).

[28] See Phlips [69] and Pollak and Wales [74].

Here, b_i is the minimum required quantity of good i, and we assume that $\Sigma\beta_i = 1$ and $q_i - b_i > 0$ for all i. Maximizing this utility function subject to the budget constraint yields

$$q_i = b_i + \frac{\beta_i}{p_i}\,(y - \sum_{i=1}^{N} p_i b_i) \tag{A8}$$

where y is income. Note that by writing total expenditures on the i^{th} good as

$$p_i q_i = p_i b_i + \beta_i\,(y - \sum_{i=1}^{N} p_i b_i) \tag{A9}$$

we see that the income remaining after the required expenditures $p_i b_i$ have been made is allocated according to the proportions β_i.

The marginal revenue function m_i corresponding to the retail demand function (A8) can be found by first taking the derivative of that equation:

$$\frac{\partial p_i}{\partial q_i} = \frac{-\beta_i y + \beta_i \sum_{j\neq 1} p_j b_j}{[q_i - (1-\beta_i)b_i]^2} = -\frac{p_i}{q_i - (1-\beta_2)b_i} \tag{A10}$$

so that $$m_i = p_i - \frac{p_i q_i}{q_i - (1-\beta_i)b_i}\ . \tag{A11}$$

Equation (A11) cannot be substituted directly into (A4); it is necessary first to eliminate p_i so that the marginal revenue m_i is written as a function of only the quantity q_i:

$$p_i = \frac{\beta_i y - \beta_i \sum_{j\neq i} p_j b_j}{q_i - (1-\beta_i)b_i} \tag{A12}$$

so that[29]

---

[29] Theoretically equation (A13) could be substituted for m in equation (A4) and we would have a wholesale demand equation that related the wholesale price of gas to the quantity of gas sold, per capita income, and the prices of <u>all other goods</u> in the linear expenditure system. Alternatively, equation (A12) could be substituted into equation (A5) and a similar relationship would result. In either case a highly non-linear equation has to be estimated involving prices for most major components of consumption in the economy. Since our objective is not to explain total consumption demand and its components, but only natural gas demand, this use of a full linear expenditure system is not promising.

$$m_i = \left(\frac{\beta_i y - \beta_i \sum_{j \neq i} p_j b_j}{q_i - (1-\beta_i) b_i}\right)\left(1 - \frac{q_i}{q_i - (1-\beta_i) b_i}\right) . \tag{A13}$$

A.2. Linear Model for "New" Residential Demand

Let us begin instead with a retail demand function that has the same form as the wholesale demand function described in Section 3.6.1 above. Write new retail demand as

$$\delta Q_t = Q_t - (1-r)Q_{t-1} = a_o - a_1 P_{g,t} + a_2 PO_t + a_3 \delta Y_t \tag{A14}$$

or equivalently,

$$P_{g,t} = b_o - b_1 \Delta Q_t - b_1 r Q_{t-1} + b_2 PO_t + b_3 \delta Y_t . \tag{A15}$$

Then $$\frac{\partial P_{g,t}}{\partial Q_{t-1}} = -b_1 r \tag{A16}$$

and $$m = b_o - b_1 \Delta Q_t - 2b_1 r Q_{t-1} + b_2 PO_t + b_3 \delta Y_t \tag{A17}$$

Now substituting (A17) into (A4), assuming λs is small, and taking the interest rate to be approximately constant, we have:

$$P_w = b_o - b_1 \delta Q_t - b_1 r Q_{t-1} + b_2 PO_t + b_3 \delta Y_t - \alpha \gamma_1 \gamma_2 Q_t^{\gamma_2 - 1} \tag{A18}$$

or $$\delta Q_t + r Q_{t-1} = \alpha_o + \alpha_1 P_w + \alpha_2 PO_t + \alpha_3 \delta Y_t - \alpha_4 Q_t^{\gamma_2 - 1} . \tag{A19}$$

Equation (A19) is an estimating equation for wholesale demand (by public utilities) that accounts for the regulatory constraint.[30]

[30] Our ability to actually fit the equation, however, depends on the stability of α_4, which in turn depends on the Lagrange multiplier and the allowed rate of return s. If λ and s are constant across states (as opposed to being constant across companies <u>within</u> states), then α_4 is a stable parameter and (A19) can be estimated using a non-linear estimation procedure. There is still the problem that the last term will be correlated with the error terms. In order to obtain consistent estimates one must perform the instrumental variable regression and then use a fitted series $\hat{Q}_t$ in place of Q_t on the right-hand side of (A19). Note that PO_t is the <u>retail</u> oil price, but presumably a wholesale oil price could be used as a proxy.

CHAPTER 4:

STATISTICAL ESTIMATION OF THE ECONOMETRIC MODEL

In this chapter we will discuss, using pooled cross-section and time-series data, the estimation of the blocks of structural equations specified in the last chapter. In most cases a number of alternative forms will be estimated for each equation. In some cases these alternative forms will be based on different starting assumptions in the specification and will thus differ considerably from each other (e.g., production out of reserves equations). In other cases the forms will differ only in lag structure or choice of exogenous variables (e.g., wholesale gas and oil demand); here the theory suggests a general equation form, but econometric tests are needed to determine the time lags and particular exogenous variables that provide the best fit to the data.

In the next section of this chapter we concentrate on the explanation of problems involved in estimating a model such as this, as well as on the particular econometric methods that were used. The data used, and the sources of that data, are described in some detail in the following section. In the remaining sections we present the estimation results themselves on a block-by-block basis, following the order of the summary table of structural equations in the last chapter.

The equations of this model cannot all be estimated using the same regional groupings or the same time bounds. Obviously regional groupings are different for field market and wholesale demand equations, but, even within field markets, exploration and discovery equations use different regional groupings than production equations. The reason for this is that in pooling data we designate regions on the basis of homogeneity in certain characteristics, and the characteristics that are relevant depend very much on what it is that is being modeled by the particular equation. Thus an equation describing exploratory well drilling can be estimated over all production districts (with the exception of offshore Louisiana), since heterogeneities in the structure of final sales are not relevant. These heterogeneities are very relevant, however, to an equation that describes production of gas out of reserves, so that in fact different production equations are estimated over four separate and distinct groups of production districts. The regional breakdown for wholesale demand is based on a similar criterion; separate equations are estimated for what we see as five separate "market" regions across the U.S., each of which is roughly homogeneous.

The time bounds used in the regressions are also different for different equations. This is the case for a variety of reasons. First, the time horizon for which data are available for estimating one part of the model (e.g., exploration and discovery) is different from that for data which applies to another part of the model. However, even if data were available over a homogeneous horizon, we might not wish to use all of that data in estimating particular equations. For one thing, we would like the time horizon to reflect a period of structural stability for the relationships described by the equation, and that period could be different for different parts of the model. Also, we do not wish to include in the time horizon those years for which a particular equation is not identifiable. Thus, industrial demand equations for gas are estimated over the years 1963 to 1969, while residential/commercial equations are estimated over the years 1963 to 1971. This is done because there was already excess demand for industrial gas by 1970, so that the demand equations would not be identifiable in 1970 and 1971.

The groupings and time bounds actually used are summarized for the equations of the model in Table 4.1 They will be discussed in detail as we examine the statistical results for individual equations in this chapter.

4.1. Estimation Methods

A number of problems must be considered when estimating a model such as this with the data and groupings that have been used here. Of first importance is multi-equation simultaneity and its implications regarding the assumptions

Table 4.1
CROSS-SECTIONS AND TIME BOUNDS
FOR THE MODEL'S STOCHASTIC EQUATIONS

EQUATIONS	DISTRICTS POOLED	TIME BOUNDS
WELLS (WXT)	18 FPC DISTRICTS*	69-72
DISCOVERY SIZE FOR GAS (SZG)	"	67-72
SUCCESS RATIO FOR GAS (SRG)	"	68-72
EXTENSION FOR GAS (XG)	"	65-72
REVISIONS FOR GAS (RG)	"	65-72
DISCOVERY SIZE FOR OIL (SZO)	"	69-72
SUCCESS RATIO FOR OIL (SRO)	"	69-72
EXTENSIONS FOR OIL (XO)	20 FPC DISTRICTS**	67-72
REVISIONS FOR OIL (RO)	"	69-72
WILDCATS DRILLED OFFSHORE (WWT)	LOUISIANA SOUTH (OFFSHORE)	58-72
SIZE OF DISCOVERY PER WILDCAT DRILLED (SZGW)	"	59-72
EXTENSIONS & REVISIONS FOR WILDCATS (XRG)	"	58-72
PRODUCTION FROM RESERVES (QG)		
PERMIAN	NEW MEXICO SOUTH, TEXAS 7C, 8, 8A	58-71
GULF COAST AND MID-CONTINENT	KANSAS, LOUISIANA SOUTH (ONSHORE), OKLAHOMA, TEXAS 1, 2, 3, 4, 10.	63-71
OTHER CONTINENTAL	COLORADO + UTAH, LOUISIANA NORTH, MISSOURI, MISSISSIPPI, NEW MEXICO NORTH, PENNSYLVANIA, TEXAS 6, 9, WEST VIRGINIA + KENTUCKY, WYOMING	63-71
LOUISIANA SOUTH (OFF-SHORE)	LOUISIANA SOUTH (OFFSHORE)	60-73
PIPELINE PRICE MARKUP	40 DEMAND REGIONS	63-71

---

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

**These include the above 18 plus Montana and Pennsylvania.

EQUATIONS	DISTRICTS POOLED	TIME BOUNDS
RESIDENTIAL AND COMMERCIAL DEMAND FOR GAS (δTRCS)		
NORTHEAST	NEW ENGLAND, NEW JERSEY, NEW YORK, PENNSYLVANIA, OHIO, MARYLAND + DELAWARE + WASHINGTON, D.C., VIRGINIA, WEST VIRGINIA	63-71
NORTH CENTRAL	ILLINOIS, INDIANA, MICHIGAN, WISCONSIN, IOWA, MINNESOTA, MISSOURI, NEBRASKA, SOUTH DAKOTA	"
SOUTHEAST	FLORIDA, GEORGIA, NORTH CAROLINA, SOUTH CAROLINA, ALABAMA, KENTUCKY, TENNESSEE	"
SOUTH CENTRAL	KANSAS, ARKANSAS, OKLAHOMA, TEXAS, MISSISSIPPI, LOUISIANA	"
WEST	ARIZONA, COLORADO, IDAHO, NEVADA, NEW MEXICO, UTAH, WYOMING, CALIFORNIA, WASHINGTON, OREGON	"
INDUSTRIAL DEMAND FOR GAS (δTINS)		
NORTHEAST	(SAME STATES AS BEFORE)	63-69
NORTH CENTRAL	"	"
SOUTHEAST	"	"
SOUTH CENTRAL	"	"
WEST	"	"
DEMAND FOR GAS AS FIELD EXTRACTION FUEL (FS)	ARKANSAS, CALIFORNIA, COLORADO KANSAS, LOUISIANA, MISSISSIPPI, NEW MEXICO, OHIO, OKLAHOMA, PENNSYLVANIA, TEXAS, UTAH, WYOMING	68-72
RESIDENTIAL AND COMMERCIAL DEMAND FOR OIL (δQO.2)		
NORTHEAST	(SAME STATES AS BEFORE)	64-70
NORTH CENTRAL	"	"
SOUTHEAST + SOUTH CENTRAL + WEST	"	"
INDUSTRIAL DEMAND FOR OIL (δRSID)		
NORTHEAST	"	"
NORTH CENTRAL	"	"
SOUTHEAST + SOUTH CENTRAI + WEST	"	"

of ordinary least squares regression. A multi-equation model which is completely simultaneous across all equations should of course be estimated using two-stage least squares, since the presence of simultaneity will result in correlations between the additive error terms and the independent variables. Many large econometric models, however, are block recursive, so that equations are simultaneous only within individual blocks of the model. In this case two-stage least squares can be applied on a block-by-block basis.

Our model of natural gas is "almost" block recursive. Also, within some blocks there is little or no simultaneity. The model can be broken up into three large blocks of equations - for reserve additions, for production, and the third for wholesale gas and oil demand - and the simultaneous interaction among these blocks is weak. For example, the set of equations for new reserves does not require simultaneous determination of wholesale demands, and while additions to reserves have an impact on demands through wholesale prices, this impact occurs over a number of years since price increases are rolled in. Also, although equations for production out of reserves do contain total reserves as an independent variable, and thus there is technically some simultaneity between new reserves and production, the simultaneity can be ignored because additions are a small portion of total reserves, and two-stage least squares need not be applied to the estimation of production out of reserves. This is not the case, however, with equations for wholesale gas demand and for pipeline price markups. Thus two-stage least squares is applied to wholesale demand equations containing unlagged price variables.

There are important issues that must be discussed related to the characteristics of the additive error terms, and how these characteristics should be modeled when estimating equations. Let us write an equation to be estimated as

$$Y_{jt} = \beta_1 X_{jt,1} + \beta_2 X_{jt,2} + \dots + \beta_k X_{jt,k} + \varepsilon_{jt} \qquad (1)$$

and let N = number of cross-sections
T = number of time periods
k = number of independent variables (including constant term).

Then we can write (1) in matrix form as

$$\underline{Y} = \underline{X}\ \underline{\beta} + \underline{\varepsilon} \quad . \tag{2}$$

Now it is probably unreasonable to assume that the error terms ε_{jt} are homoscedastic and independent both across time and across cross-sections, i.e. that they have a covariance matrix of the form:

$$\underline{\Omega} = E[\underline{\varepsilon}\ \underline{\varepsilon}'] = \sigma^2\underline{I} \quad . \tag{3}$$

It would be quite reasonable, in fact, to expect that the error terms are heteroscedastic, and that they may be correlated across time and across cross-sections.

Let us first consider the problem of autocorrelation of the error terms. If the equation is estimated by ordinary least squares (OLS), and if there is autocorrelation, we can expect that the resulting estimates will at best be consistent and unbiased, but inefficient, as long as the equation does not contain a lagged dependent variable or independent variables referenced across districts [32]. The Durbin-Watson statistic might indicate the presence of autocorrelation in the error terms, but it will not tell us what part of the autocorrelation is across time and what part is between cross-sections. Furthermore, the standard correction techniques, such as Hildreth-Lu [34], cannot be used directly since the autocorrelation is two-dimensional.

4.1.1. Cross-Sectional Autocorrelation

The problem of autocorrelation in the cross-section dimension is often the result of a mis-specification that can be anticipated. Suppose, for example, that new discoveries of gas (DG) is believed to be linearly related to the number of wells drilled (W), so that the equation to be estimated is

$$DG_{j,t} = \beta_0 + \beta_1 W_{j,t} + \varepsilon_{j,t} \quad . \tag{3}$$

It is reasonable, however, to believe that geological differences make some regions richer in gas than others, and therefore the wells in those regions have a higher average "output". Perhaps in any given year, the same number of wells per district in each of two different districts j and j' can be expected to result in different amounts of discoveries. This would result in cross-sectionally autocorrelated errors in equation (3).[1]

[1]Consider two different districts, j and j', with average "output ratios" given by

$$\frac{1}{T} \sum_{t=1}^{T} \left(\frac{DG_{j,t}}{W_{j,t}}\right) = \alpha_j \tag{i}$$

and
$$\frac{1}{T} \sum_{t=1}^{T} \left(\frac{DG_{j',t}}{W_{j',t}}\right) = \alpha_{j'} \quad . \tag{ii}$$

Thus, if the number of wells in these two districts were always the same, we would still expect to find on the average that

$$DG_{j,t} = \frac{\alpha_j}{\alpha_{j'}} DG_{j',t} = \theta_{jj'} DG_{j't} \quad . \tag{iii}$$

A model, then, that would account only for the geological differences between districts j and j' would be

$$DG_{j,t} = \theta_{jj'} DG_{j',t} + \varepsilon^*_{j,t} \tag{iv}$$

where the error term $\varepsilon^*_{j,t}$ is independent of j. Now if equation (iv) is substituted for $DG_{j,t}$ in (3), and the resulting equation is written with $\varepsilon_{j,t}$ on the left-hand side, we have

$$\varepsilon_{j,t} = \theta_{jj'} DG_{j',t} - \beta_0 - \beta_1 W_{j,t} + \varepsilon^*_{j,t} \quad . \tag{v}$$

But $DG_{j',t} = \beta_0 + \beta_1 W_{j',t} + \varepsilon_{j',t}$, and substituting this into (v) gives us

$$\varepsilon_{j,t} = \theta_{jj'} \beta_1 W_{j',t} - \beta_1 W_{j,t} + \theta_{jj'} \beta_0 - \beta_0 + \varepsilon^*_{j,t} + \theta_{jj'} \varepsilon_{j',t} \tag{vi}$$

so that
$$E[\varepsilon_{j,t}\ \varepsilon_{j',t}] = \theta_{jj'} \sigma^2_\varepsilon \tag{vii}$$

and the errors are thus autocorrelated. Errors autocorrelated in time can occur in the same way. Consider the regression equation $Y_t = \beta X_t + \varepsilon_t$ with an unexplained time trend; e.g., $Y_t = \rho Y_{t-1}$ and $X_t = \rho X_{t-1}$. Then, $\varepsilon_{t-1} = Y_{t-1} - \beta X_{t-1}$ $= \rho Y_t - \beta\rho X_t = \rho\varepsilon_t$, so that $E[\varepsilon_t\ \varepsilon_{t-1}] = \rho\sigma^2_\varepsilon$.

In order to account for such cross-sectional autocorrelation one should estimate the equation using a full generalized least squares procedure which provides a full error covariance matrix.[2] With limited data the unrestricted estimation of all off-diagonal elements of this covariance matrix can be difficult (and in fact misleading) since the estimates themselves will have large variances. Furthermore, even if a full error covariance matrix could be estimated, this generalized least squares procedure could be computationally very costly. As a result, we felt that it would be preferable to introduce, where necessary, regional variables (geological or economic) to explain heterogeneity across districts pooled in the sample. If this is done properly, most of the autocorrelation across districts can be removed. An equation for new discoveries such as (3), for example, should be re-specified in the form:

$$DG_{j,t} = \beta_0 + \beta_1 W_{j,t} + \beta_2 \alpha_j + \varepsilon_{j,t} \tag{4}$$

where α_j is a geographical "output" variable. Thus, although we will in fact use a generalized least squares procedure, it is a limited procedure that accounts for autocorrelation across time (and not cross-sections) - as well as cross-sectional heterscedasticity.

4.1.2. Time-Wise Autocorrelation and Cross-Sectional Heteroscedasticity

Autocorrelation of the error terms across time will result from trends in variables that are not explained by the structural specification. It is a problem that occurs frequently but that can be corrected relatively easily. Cross-sectional heteroscedasticity of the error terms can also be expected, since error variances in equations are likely to be larger for large districts than for small districts. This problem can also be corrected.

When estimating the equations of our model we will assume the following about the error covariance matrix $\underline{\Omega} = E[\underline{\varepsilon}\ \underline{\varepsilon}']$:

[2] For a discussion of how this could be done, see Kmenta [45], pp. 512-514.

with variances σ_u^2, σ_v^2, and σ_w^2. It is assumed that u_j, v_t, and w_{jt} are all independent of each other and that $E[u_j u_{j'}] = 0$ for $j \neq j'$, $E[v_t v_{t'}] = 0$ for $t \neq t'$, and $E[w_{jt} w_{j't}] = E[w_{jt'} w_{jt}] = E[w_{j't'} w_{jt}] = 0$ for $j \neq j'$ and $t \neq t'$.

Given these assumptions about the error vector ε_{jt}, one can write its covariance matrix as $\underline{\Omega} = E[\underline{\varepsilon}\ \underline{\varepsilon}'] = \sigma_u^2 \underline{A} + \sigma_v^2 \underline{B} + \sigma_w^2 \underline{I}_{NT}$. Note that $\underline{\Omega}$ is an NT×NT matrix. I_{NT} is an NT×NT identity matrix, and A and B are NT×NT matrices defined by

$$\underline{A} = \begin{bmatrix} \underline{J}_T & 0 & \cdots & 0 \\ 0 & \underline{J}_T & \cdots & 0 \\ \vdots & & & \\ 0 & \cdots & \cdots & \underline{J}_T \end{bmatrix}$$

where $\underline{J}_T$ is a T×T matrix of ones, and

$$\underline{B} = \begin{bmatrix} \underline{I}_T & \underline{I}_T & \cdots & \underline{I}_T \\ \underline{I}_T & \underline{I}_T & \cdots & \underline{I}_T \\ \vdots & & & \vdots \\ \underline{I}_T & \underline{I}_T & \cdots & \underline{I}_T \end{bmatrix}$$

where $\underline{I}_T$ is a T×T identity matrix.

If the variance components σ_w^2, σ_u^2, σ_v^2 are known, then the minimum variance estimate of $\underline{\beta}$ is given by the GLS estimate $\hat{\underline{\beta}} = (\underline{X}'\underline{\Omega}^{-1}\underline{X})^{-1}\underline{X}'\underline{\Omega}^{-1}\underline{Y}$. If the variance components are not known (which would presumably be the case), then Zellner's method [110] can be used, where consistent (but inefficient) estimates of $\underline{\beta}$ are obtained by OLS, the residuals are used to obtain consistent estimates of σ_w^2, σ_u^2, and σ_v^2, and GLS is finally used to obtain a new (and efficient) estimate of $\underline{\beta}$.

The problem with this method is that while it accounts for differences in the variances of the error components, it does not account for heteroscedasticity or autocorrelations <u>within</u> each error component. Thus, if the error component that is cross-sectionally generated is itself heteroscedastic or if its elements are autocorrelated through time, we will still obtain inefficient estimates for $\underline{\beta}$ (although the estimates will be more efficient than those generated by OLS).

$$E(\varepsilon_{jt}^2) = \sigma_j^2 \tag{5}$$

$$E(\varepsilon_{jt}\varepsilon_{it}) = 0 \text{ for } j \neq i \tag{6}$$

$$\varepsilon_{jt} = \rho_j \varepsilon_{j,t-1} + \tilde{\varepsilon}_{jt} \quad . \tag{7}$$

It is assumed that σ_j^2 in equation (5) will be different for different j (cross-sectional heteroscedasticity), although this will of course be tested. Equation (6) states that the errors are cross-sectionally independent, but this assumption will also be tested.[3] Equation (7) assumes first-order serial correlation in the errors. (Note that the correlation coefficient ρ_j can be different for different regions.) In order to test this assumption, and to correct for it, it is important that equations do not contain lagged dependent variables, and this will impose a restriction on the lag structure of our equations. Finally, we can write the assumptions of (5), (6), and (7) in matrix form as:

$$\underline{\Omega} = \begin{bmatrix} \sigma_1^2 \underline{P}_1 & \underline{0} & \cdots & \underline{0} \\ \underline{0} & \sigma_2^2 \underline{P}_2 & \cdots & \underline{0} \\ \vdots & \vdots & & \\ \underline{0} & \underline{0} & \cdots & \sigma_N^2 \underline{P}_N \end{bmatrix} \tag{8}$$

$$\text{with } \underline{P}_j = \begin{bmatrix} 1 & \rho_j & \rho_j & \cdots & \rho_j^{T-1} \\ \rho_j & 1 & \rho_j & & \rho_j^{T-1} \\ \vdots & \vdots & \vdots & & \vdots \\ \rho^{T-1} & \rho^{T-2} & \rho^{T-3} & & 1 \end{bmatrix} \quad . \tag{9}$$

---

[3] If for certain parts of the model this assumption were grossly incorrect, then the generalized least squares estimation procedure would have to be complicated by including cross-sectional correlation in the error covariance matrix. Fortunately we did not find this to be the case.

Our objective is to estimate equation (2) using generalized least squares, i.e. to calculate

$$\underline{\hat{\beta}} = (\underline{X}'\underline{\Omega}^{-1}\underline{X})^{-1} (\underline{X}'\underline{\Omega}^{-1}\underline{Y}) \quad . \tag{10}$$

To do this we must obtain consistent estimates of the parameters σ_j and ρ_j.[4]

4.1.3. Estimation Procedure.

As long as the equation to be estimated contains no lagged dependent variables we can obtain consistent (though inefficient) estimates of $\underline{\beta}$ by applying ordinary least squares. We begin, then, by applying OLS to the equation using all NT observations. Then, we calculate the regression residuals u_{jt} and obtain estimates of ρ_j from:

$$\hat{\rho}_j = \frac{\sum_{t=2}^{T} \tilde{u}_{jt}\tilde{u}_{j,t-1}}{\sum_{t=2}^{T} \tilde{u}^2_{j,t-1}} \tag{11}$$

with $$\tilde{u}_{jt} = u_{jt} - \bar{u}_j \tag{12}$$

---

[4]Our procedure is essentially that described by Kmenta [45], Section 12.2. It should be pointed out that other approaches exist to estimate models using pooled cross-section and time-series data. One approach that is commonly used involves the assumption that the error terms are made up of components that originate from different sources and that therefore have different variances. The "residual" or "error components" model was first suggested by Kuh [46], and later generalized and applied by Balestra and Nerlove [9] and Wallace and Hussain [106]. The approach assumes that the error term of equation (1) is made up of three independent components, one of which is associated with time, one with the cross-sections, and the last an independent random variable across both time and cross-sections, i.e., $\varepsilon_{j,t}$ is given by

$$\varepsilon_{j,t} = u_j + v_t + w_{jt}$$

(footnote continued on p. 9a)

where $\bar{u}_j$ is the mean of u_{jt} over time. Thus equation (11) can be written equivalently as

$$\hat{\rho}_j = \frac{\sum_{t=2}^{T} u_{jt}u_{j,t-1} - (T-1)(\bar{u}_j)^2}{\sum_{t=2}^{T} (u_{j,t-1} - \bar{u}_j)^2} \quad . \tag{13}$$

This can be shown to be a consistent estimate of ρ_j.[5] For now we will assume that the individual $\hat{\rho}_j$ differ significantly from each other; if this is not the case then a single estimate $\hat{\rho}$ can be obtained and the estimation procedure somewhat simplified.

The equation's variables can then be transformed autoregressively as follows:

$$\left.\begin{aligned} Y^*_{jt} &= Y_{jt} - \hat{\rho}_j Y_{j,t-1} \\ X^*_{jt,1} &= X_{jt,1} - \hat{\rho}_j X_{j,t-1,1} \\ &\vdots \\ X^*_{jt,k} &= X_{jt,k} - \hat{\rho}_j X_{j,t-1,k} \\ \varepsilon^*_{jt} &= \varepsilon_{jt} - \hat{\rho}_j \varepsilon_{j,t-1} = \tilde{\varepsilon}_{jt} \end{aligned}\right\} \tag{14}$$

where $\tilde{\varepsilon}_{jt}$ is just the non-autocorrelated part of ε_{jt}. Ordinary least squares is at this point applied to the following equation:

$$\underline{Y}^* = \underline{X}^* \underline{\beta} + \underline{\varepsilon}^* \quad . \tag{15}$$

Note that now N(T-1) observations can be used. The <u>resulting regression residuals</u>, call them u^*_{jt}, can be used to obtain consistent estimates of

---

[5]See Kmenta [45], Section 8.2. Kmenta assumes the mean of the residuals $\bar{u}_j$ to be zero, and this would indeed be the case in a pure time series regression or in a pooled regression in which the mean is taken over all years <u>and</u> all districts. In a pooled regression, however, the mean of the residuals over time for <u>an individual district</u> may not be zero, and our formula for $\hat{\rho}_j$ in equation (13) differs from Kmenta's in that we take this non-zero mean into account.

the variances σ_j^2. First, we can get a consistent estimate of the variance of $\tilde{\varepsilon}_{jt}$ (for each j) from

$$\hat{\sigma}^2_{\tilde{\varepsilon}_j} = \frac{1}{T - k - 1} \sum_{t=2}^{T} (u^*_{jt})^2 \quad . \tag{16}$$

Then, since $\sigma^2_{\tilde{\varepsilon}_j} = \sigma_j^2(1 - \rho_j^2)$ (17)

we can obtain a consistent estimate of σ_j^2 from

$$\hat{\sigma}_j^2 = \frac{\hat{\sigma}^2_{\tilde{\varepsilon}_j}}{1 - \hat{\rho}_j^2} \quad . \tag{18}$$

Now equation (2) is estimated by generalized least squares using the estimates $\hat{\rho}_j$ and $\hat{\sigma}_j^2$ that have just been obtained in the matrix $\underline{\Omega}$. Equivalently, ordinary least squares can be applied to the equation

$$\underline{Y}^{**} = \underline{X}^{**}\beta + \varepsilon^{**} \tag{19}$$

where[6] $$Y^{**}_{jt} = Y^*_{jt}/\hat{\sigma}_{\tilde{\varepsilon}_j} \tag{20}$$

$$X^{**}_{jt,i} = X^*_{jt,i}/\hat{\sigma}_{\tilde{\varepsilon}_j} \qquad (i = 1,...k) \tag{21}$$

$$\varepsilon^{**}_{jt} = \varepsilon^*_{jt}/\hat{\sigma}_{\tilde{\varepsilon}_j} \quad . \tag{22}$$

The error terms ε^{**}_{jt} in equation (19) are now homoscedastic and non-serially correlated. Thus the standard errors computed from the OLS estimates of (19) are consistent estimates of the standard deviations

---

[6]Note that the weights in (20), (21), and (22) are the estimated <u>standard deviations</u> (not variances) of the uncorrelated part of the error term.

of the $\hat{\beta}_i$, and the t-statistics can be interpreted accordingly. The R^2 of the regression may, of course, be scaled down (due to the transformations of the dependent variables in (14) and (20), but a lower R^2 (as compared to simple OLS estimates) does not mean that there is "less explanation". The statistic simply indicates the amount of variance explained by the structural relationship, as opposed to variance explained by trend, etc.[7]

Best linear unbiased (BLU) forecasts are obtained using the transformed version of the equation, i.e. the estimated version of (19).[8] Of course, after a forecast simulation has been performed the variables must be transformed back to their original form for purposes of analysis.

---

[7]It may be that the ρ_j's do not differ significantly across cross-sections. If this is the case a single estimate of ρ can be obtained from:

$$\hat{\rho} = \frac{\sum_j \sum_t u_{jt} u_{j,t-1}}{\sum_j \sum_t u_{j,t-1}^2} .$$

Then OLS can be performed on the transformed equation (19) using a single value of ρ.

One can also test to determine whether the error terms are indeed cross-sectionally independent. This can be done by obtaining the residuals u_{jt}^{**} from the OLS estimate of (19) and calculating estimates of the covariances σ_{ij} from:

$$\hat{\sigma}_{ij} = \frac{\hat{\phi}_{ij}}{1 - \hat{\rho}_i \hat{\rho}_j}$$

where $$\hat{\phi}_{ij} = \frac{1}{T - k - 1} \sum_{t=2}^{T} u_{it}^{**} u_{jt}^{**} .$$

If these covariances are large a full GLS estimation would be necessary in order to ensure efficiency. (See Kmenta [45]).

[8]Our estimator is best linear unbiased with the class of single-equation estimators. More efficient estimates could result from the use of a system estimator such as three-stage least squares.

Certain equations in the model (e.g., the equations for wholesale gas demand) must be estimated using two-stage least squares. In combining this method with generalized least squares, consistent estimates are obtained by first performing a GLS transformation on the equation, and then applying two-stage least squares (TSLS) using the transformed variables.[9] The steps are therefore as follows: First, the parameters ρ_j and σ_j must be estimated consistently. This means that TSLS, rather than OLS, is applied first to equation (2) to obtain the estimates $\hat{\rho}_j$, and then to equation (15) to obtain the estimates $\hat{\sigma}_j$. Then, using these estimated parameter values, we apply TSLS to equation (19), i.e., we regress $\underline{X}^{**}$ (or those components of $\underline{X}^{**}$ believed to be correlated with the error term) on exogenous and lagged variables in order to obtain a constructed instrument $\hat{\underline{X}}^{**}$, and then perform ordinary least squares on

$$\underline{Y}^{**} = \hat{\underline{X}}^{**}\underline{\beta} + \underline{\varepsilon}^{**} \quad . \tag{23}$$

This procedure was in fact necessary only for relatively few equations of the model.

4.2. The Gas-Oil Data Base

All of the variables used in this model, together with their definitions, units of measurement, and sources of data, are listed below. The list of variables is divided into functional groups, including wells, offshore acreage, reserves, production, demand, and prices.

WELLS.	Exploratory wells data are from the Joint Association Survey of Drilling Statistics, for 18 FPC production districts, for the years 1963 - 1972.
WXT:	Total number of exploratory wells drilled.

[9] See Eisner and Pindyck [25].

WXG: Number of successful exploratory gas wells.

WXO: Number of successful exploratory oil wells.

SRG: Ratio of successful gas wells to total exploratory wells. SRG = WXG/WXT.

SRO: Ratio of successful oil wells to total exploratory wells. SRO = WXO/WXT.

$\hat{SRG}$, $\hat{SRO}$: Fitted values of the above two variables using the estimated success ratio equations.

CWXT: Cumulative number of exploratory wells drilled (WXT) from 1963 to year t.

$$CWXT_t = \sum_{t'=1963}^{t} WXT_{t'}$$

WWT: Number of wildcat wells drilled. (Wildcat wells are a more narrow class of exploratory wells that excludes extension wells.) From World Oil Magazine, for offshore Louisiana, for the years 1958-1972.

CWWT: Cumulative number of wildcat wells drilled to year t.

$$CWWT_t = \sum_{t'=1958}^{t} WWT_{t'}$$

FWT: Number of offshore field wells drilled (i.e., all wells except wildcats, including development wells and exploratory extension wells). From World Oil Magazine, for offshore Louisiana, for the years 1958-1972.

FWT: Number of offshore field wells drilled (i.e., all wells except wildcats). From World Oil Magazine, for offshore Louisiana, for the years 1958 - 1972.

DRO: Number of offshore drilling rigs. From World Oil Magazine, for Offshore Louisiana, for the years 1958 - 1972.

ACREAGE. Acreage data are from: Outer Continental Shelf Statistics, U.S. Dept. of the Interior, Geological Survey - Conservation Division, Washington, D.C., June 1973. Data are for offshore Louisiana, for the years 1954 - 1972.

ACT: Total acreage under supervision.

ACP: Producing acreage under supervision.

ACN: Non-producing acreage under supervision.

ACR: Acreage leased.

ACPN: New Producing acreage, $ACPN_t = ACP_t - ACP_{t-1}$. (Assumption: no producing acreage forfeited)

ACRD: Acreage forfeited, $ACRD_t = ACT_{t-1} + ACR_t - ACT_t$. If ACRD is less than 0, then it is assumed that this amount of acreage was given to the Bureau of Land Management from the states by the courts.

CACR: Cumulative number of acres leased.

RESERVES. All data are from American Gas Association/American Petroleum Institute/Canadian Petroleum Association, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas, for 18 FPC production districts for the years 1964-1972. Units are millions of cubic feet for natural gas, and thousands of barrels for oil. Exceptions to this are explicitly stated, and include offshore data for 1958-1972.[10]

DD1: Dummy variable for Louisiana South District.

DD2: Dummy variable for Permian District.

DD3: Dummy variable for Kansas, Oklahoma, TRRC Districts 1, 2, 3, 4, and 10.

DD4: Dummy variable for Colorado-Utah, and Wyoming Districts.

DG: Total new discoveries of natural gas.

DO: Total new discoveries of oil.

RG: Total revisions of natural gas.

RO: Total revisions of oil.

XG: Total extensions of natural gas.

XO: Total extensions of oil.

XRG: Natural gas extensions plus revisions, XRG = XG + RG.

YG: Year end reserves of natural gas.

YO: Year end reserves of oil.

---

[10] Reserves data for Offshore Louisiana are from The Special Report on Louisiana Offshore (Zones 2, 3, 4), 1954 - 1972, by American Gas Association, Committee on Natural Gas Reserves. Also, oil reserves data are available for 20 FPC districts, and were used in the estimation of equations, whenever feasible.

SZG: Average size of gas discoveries per successful gas well, SZG = DG/WXG.

SZO: Average size of oil discoveries per successful oil well, SZO = DO/WXO.

$\hat{SZG}$, $\hat{SZO}$: Fitted values of the above two variables, obtained from the estimated size of discovery equations.

σ_G^2, σ_O^2: Estimates of the variance over time of the size distributions of gas and oil discoveries respectively. These are obtained from the estimated size of discovery equations.

PGC_G: Estimate of the total potential gas reserves in each district as of 1963. From Potential Supply of Natural Gas in the U.S., published by the Potential Gas Association, Mineral Resources Institute, 1971.

PCG_O: Estimate of the original oil-in-place in the district.

DEPG: Index of depletion of the natural gas resource base in the production districts,[11]

$$DEPG = (PGC_G - YG - CQG)/PGC_G$$

DEPO: Index of depletion of the oil resource base in the production district,

$$DEPO = (PGC_O - YO - CQO)/PGC_O$$

PRODUCTION. Data are from AGA/API/CPA, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas, for 18 FPC production districts,[12] for the years 1961-1972. Units are 10^6 cubic feet for gas and 10^3 barrels for oil.

QG: Total production of natural gas.

QO: Total production of oil.

CQG: Cumulative production of natural gas,

$$CQG = \sum_{t'=1963}^{t} QG_{t'}$$

---

[11] See list of production variables for definition of CQG and CQO.

[12] Production data for Offshore Louisiana are available for 1955 - 1973. The source is The Special Report on Louisiana Offshore.

CQO: Cumulative production of oil,

$$CQO = \sum_{t'=1963}^{t} QO_{t'}$$

<u>DEMAND</u>. Data are available for 40 demand regions, for the years 1962 - 1972. Units are 10^6 cubic feet for gas and 10^3 barrels for oil.

AL, AR, AZ, CA,..., WY: Dummy variables for the 40 demand regions (conforming to the postal code except for NE ≡ New England).

TDUM: Dummy variable for time, such that TDUM = 0 if the year is 1970 or later and 1 otherwise.

MS: Mainline industrial sales of natural gas by interstate pipeline companies. Data on mainline sales by company and state were extracted from the Federal Power Commission's annual Form 2 reports of jurisdictional interstate pipeline companies. This data was then aggregated into our 40 demand region breakdown of the U.S.

INTRA: Total intrastate sales, determined by subtracting total sales by producers of natural gas to interstate pipeline companies (as determined from the FPC's annual <u>Sales by Producers of Natural Gas to Interstate Pipeline Companies</u>) from total state gas production (as determined from AGA/API/CPA's annual <u>Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas</u>).

CS: Direct (retail) sales to communities by interstate natural gas pipeline companies, as extracted from FPC Form 2 reports, and aggregated as previously described.

TSS: Total sales for resale of natural gas as extracted from Form 2 reports and aggregated over the 40 region breakdown. This does not include sales for resale to other interstate pipeline companies, but only to intrastate natural gas distribution companies.

FS: Lease and plant fuel sales. Extracted from Bureau of Mines, annual <u>Minerals Yearbook</u>.

f: The ratio of industrial gas consumption to total gas consumption, both quantities as compiled by Bureau of Mines, <u>Minerals Yearbook</u>.

TINS: Total sales going to industrial uses,

$$TINS = f \cdot (MS + INTRA + CS + TSS)$$

TRCS: Total residential and commercial sales,

$$TRCS = (1 - f) \cdot (MS + INTRA + CS + TSS)$$

QO.2: Oil quantities sold in the residential/commercial market, obtained from API Petroleum Facts and Figures. The name of the series is "Sales of Heating Oil, Grade No. 2, by States, 1937 - 1970".

RSID: Oil quantities sold in the industrial market, obtained from the above source. The name of that series is "Total Sales of Residual Fuel Oils (All Uses), by States, 1934 - 1970".

PRICES AND ECONOMIC VARIABLES.

PG: New contract price of interstate sales of gas at the wellhead, in cents per Mcf, by production district for 28 FPC production districts, for the years 1952 - 1972. Compiled by Foster Associates, Inc.

PW or $\overline{PG}$: Average wellhead price, in cents per Mcf, by production district for 18 FPC production districts, for the years 1962 - 1971, from Table F, FPC, Sales of Natural Gas. Average wellhead prices for each of the eight aggregated producing regions used in the pipeline price markup equations were computed by weighting the average price on all contracts for each FPC district comprising that region by the total production in each district. In computing average wellhead prices (before markup) for each consuming region (i.e., each state), weights equal to the fraction of consumption coming from each producing region are applied to the average producing region prices.

PGW: Average wholesale price of gas, in dollars per Mcf, by state, for the years 1962 - 1972. Determined from FPC Form 2 Reports. This series is a weighted average price for mainline sales, interstate sales for resale, and intrastate sales of natural gas. It was used as the price of natural gas in both the industrial and residential/commercial equations.

MP: Average price of mainline sales of gas, in dollars per Mcf, by state, for the years 1962 to 1972. This is a wholesale market price, determined from Form 2 Reports.

SP: Average wholesale price of interstate sales for resale, in dollars per Mcf, by state, for the years 1962 to 1972. Determined from FPC Form 2 Reports. It is used as both the residential and industrial sales for resale price.

IP: Average wholesale price of intrastate gas, in dollars per Mcf, by state, for the years 1962 to 1972. Determined from FPC Form 2 Reports.

PO: Wellhead price of oil, in dollars per barrel, by production district for 20 FPC production districts, for the years 1954 - 1972, from Bureau of Mines, Minerals Yearbook.

POIL: Average price in dollars per Mcf-energy-equivalent of fuel oil paid by electric power companies, by state, for the years 1954 - 1972, from Edison Electric Institute, Statistical Annual of the Electric Utility Industry. It is assumed that this is the best available surrogate for the industrial price of residual fuel oil.

PCOAL: Average wholesale price of coal paid by the electric utility industry, in dollars per Mcf-energy-equivalent, by state, for the years 1954 - 1972 (see POIL for source).

PALT: Price of alternate fuels, in dollars per Mcf-energy-equivalent, by state, for the years 1954 - 1972 (see POIL for source). This is a weighted average (over kilowatt-hours generated) of prices of fuel oil and coal consumed by the electric utility industry in generating electric power.

PFOIL: Average wholesale price, in cents per gallon, of No. 2 fuel oil, by state, for the years 1960 - 1972, from Fuel Oil and Oil Heat and Platt's Oil Price Handbook and Oilmanac. This series was constructed from the two sources, by taking the average of the two sources in cases where there was more than one observation for the same city from each source. In cases where there was more than one city observed per state reported, a weighted average was taken by use of city population. In cases where there was no observation at all, the price for an adjacent state was used. (Eleven such assignments were made for states that were very sparse consumers of No. 2 fuel oil.)

PWG: Average wellhead price of gas, in dollars per Mcf, for Offshore Louisiana, for the years 1955 - 1973, from Outer Continental Shelf Statistics, U.S. Dept. of the Interior, Geological Survey - Conservation Division, Washington, D.C., June 1973.

PWO: Average wellhead price of oil, in dollars per barrel, for Offshore Louisiana, for the years 1957 - 1972 (see PWG for source).

INTA: AAA bond interest rate (percent per annum), from Federal Reserve Bulletin.

INT: BAA interest rate (percent per annum), for 1946 - 1973, from NBER data base.

ATCM: Index of average total drilling costs for exploratory drilling per well, by production district for 18 FPC production districts, from AGA/API/CPA's Joint Association Survey. This is a time average over the period 1963 - 1971.

VAM: Value added in manufacturing, in millions of current dollars, by state, for the years 1958 - 1971, from U.S. Department of Commerce, Bureau of the Census, Annual Survey of Manufacturers.

CAP: New capital expenditures in the manufacturing industry, in millions of current dollars, by state, for the years 1958 - 1971 (see VAM for source).

VCC: Value of construction contracts, in millions of current dollars, by state, from 1956 to 1972, from Statistical Abstract of the U.S., and from F.W. Dodge Corp., Dodge Construction Contract Statistics Service.

YY: Personal income, in millions of current dollars, by state, from 1956 to 1972, from U.S. Department of Commerce, Survey of Current Business.

NN: Population in thousands, by state, from 1955 to 1972, from U.S. Department of Commerce, Bureau of Census, Current Population Reports.

M: The weighted average distances from the centers of each of the 18 FPC producing regions to the population center of each consumption region, by state, for each of the 40 demand states. These were measured from a 1968 FPC pipeline map, with distances measured along the path of the biggest pipeline groups connecting the pairs of regions. (Canadian gas mileage, however, was measured only from the border, since the gas purchased by an interstate pipeline from a Canadian firm is assumed to have been made at the border.)

V: Pipeline volumetric capacity. As a proxy for actual flow data which was unavailable, the total cross-sectional pipeline area for gas flowing into each consuming region was measured as the capacity variable. If a state was a net exporter, the cross-sectional area of all pipelines flowing out of the state would be added on as well because the inflow figure alone underestimates the quantity of gas flowing through the state. The capacity figure is then computed by summing the squares of the relevant pipeline diameters (the diameters of each pipeline are shown on the FPC pipeline map).[13]

H: The Herfindahl Index, defined as $H_j = \sum_i x_{i,j}^2$, where $x_{i,j}$ is the fraction of gas consumed in region j provided by company i. Company sales from FPC From 2 Reports was used to calculate $x_{i,j}$ and these were aggregated to compute the index for each state each year. Since there is little variation in the market shares over time, the mean value over time is taken for each state.

[13]This sum of squared diameters measure is a valid proxy for capacity only under several assumptions. First, the pressures in each pipeline are assumed to be nearly equal; this is reasonable since pipeline pressure is usually 60 to 80 atmospheres. Secondly, it is assumed that each pipeline or pipeline group is at capacity or at the same percentage of capacity. This is difficult to validate empirically, but is consistent with the assumption of equal pressure if the pipelines are operating at maximum efficiency. The third assumption is that the pipeline structure is not changing much over time. This is well substantiated by historical data on the fractions of demand coming from given producing regions, which have been quite stable over time.

Finally, the following codes will be used to refer to specific production regions and consuming states throughout this Chapter:

CODE LETTERS FOR DISTRICTS

Consumers

1.	AL	Alabama
2.	AZ	Arizona
3.	AR	Arkansas
4.	CA	California
5.	CO	Colorado
6.	MD	Maryland Delaware District of Columbia
7.	FL	Florida
8.	GA	Georgia
9.	ID	Idaho
10.	IL	Illinois
11.	IN	Indiana
12.	IO	Iowa
13.	KS	Kansas
14.	KY	Kentucky
15.	LA	Louisiana
16.	MI	Michigan
17.	MN	Minnesota
18.	MS	Mississippi
19.	MO	Missouri
20.	NB	Nebraska
21.	NV	Nevada
22.	NE	New England
23.	NJ	New Jersey
24.	NM	New Mexico
25.	NY	New York
26.	NC	North Carolina
27.	OH	Ohio
28.	OK	Oklahoma
29.	OR	Oregon
30.	PA	Pennsylvania
31.	SC	South Carolina
32.	SD	South Dakota
33.	TN	Tennessee
34.	TX	Texas
35.	UT	Utah
36.	VA	Virginia
37.	WA	Washington
38.	WV	West Virginia
39.	WI	Wisconsin
40.	WY	Wyoming

Suppliers (for which reserves are modeled)

CA	California
COUT	Colorado + Utah
KA	Kansas
LN	Louisiana North
LX	Louisiana South (onshore)
LOF	Louisiana South (offshore)
MS	Mississippi
NN	New Mexico North
PE	Permian
OK	Oklahoma
T1	Texas 1
T2	2
T3	3
T4	4
T6	6
T9	9
T10	10
WK	West Virginia + Kentucky
WY	Wyoming

Suppliers (for which reserves are not modeled)

AR	Arkansas
CN	Canada (exogenous)
MI	Michigan
MO	Montana
NB	Nebraska
NY	New York
ND	North Dakota
OH	Ohio
PA	Pennsylvania
T5	Texas 5
T7	Texas 7

4.3. Estimated Equations for Gas and Oil Reserves

There are nine equations that determine additions to reserves for both natural gas and oil from onshore production districts. Single equations are estimated to explain the total number of exploratory wells drilled (WXT), the average sizes of new discoveries per well of natural gas (SZG) and oil (SZO), and to explain the fraction of wells successful in finding gas (SRG) and in finding oil (SRO). Together they comprise the equation set for explaining new discoveries of gas and oil. Finally, four equations are estimated that explain extensions of gas, extensions of oil, revisions of gas, and revisions of oil. After describing the discoveries equations in 4.3.1., we shall deal with the extensions and revisions equations in 4.3.2.

4.3.1. New Discoveries of Natural Gas and Oil

The theoretical relationships for the exploration and discovery of natural gas and oil that were derived in Section 3.2 must be modified for purposes of estimation. Let us begin by re-examining equation (12) of Section 3.2.1. that specifies the total number of exploratory wells drilled. Note that the equation includes the mean and variance of RWG and RWO, the average sizes of gas discoveries and oil discoveries per well drilled. From equation (23) in Section 3.2.5. we can write

$$(RWG)^V = 4\hat{\sigma}_G^2(\overline{RWG})^2 = 4\hat{\sigma}_G^2(S\hat{Z}G)^2(S\hat{R}G)^2 \tag{1}$$

$$(RWO)^V = 4\hat{\sigma}_O^2(\overline{RWO})^2 = 4\hat{\sigma}_O^2(S\hat{Z}O)^2(S\hat{R}O)^2 \tag{2}$$

where $\hat{\sigma}_G^2$ and $\hat{\sigma}_O^2$ are estimated variances of the error terms associated with the equations that determine the sizes of gas and oil discoveries respectively. The equation also contains the mean values of oil and gas discovery sizes, and we will use the estimated values of these variables (obtained from the estimated forms of the size of discovery equations) in our exploratory wells estimating equation.

The equation for the number of exploratory wells drilled also includes the expected field prices of natural gas and oil. Since it is impossible to observe expected prices, we use as proxy variables a three-year moving average of past prices. Finally, dummy variables are introduced (DD1, DD2, DD3, and DD4) to account for heterogeneity between broadly-defined field markets in the United States. This gives us the following estimating equation for exporatory wells drilled:

$$\begin{aligned}
WXT = {} & c_o + a_1 DD1 + a_2 DD2 + a_3 DD3 + a_4 DD4 \\
& + c_1[(\hat{SZG}\cdot\hat{SRG})(PG_{-1}+PG_{-2}+PG_{-3})/3 + (\hat{SZO}\cdot\hat{SRO})(PO_{-1}+PO_{-2}+PO_{-3})/3] \\
& + c_2[(\hat{SZG})^2(\hat{SRG})^2(PG_{-1}+PG_{-2}+PG_{-3})^2/9 + (\sigma_0^2/\sigma_G^2)(\hat{SZO})^2(\hat{SRO})^2(PO_{-1}+PO_{-2}+PO_{-3})^2/9] \\
& + c_3 ATCM + c_4 INTA_{-1} \quad . \qquad (3)
\end{aligned}$$

Note that this equation cannot be estimated until the size and success ratio equations for both oil and gas have also been estimated, since the equation includes the estimated values for sizes and success ratios as well as the estimated error variances for the oil and gas sizes.

The theoretical specification for the average size of discovery appears in equation (21) of Section 3.2.3. The argument is that the average discovery size at a point in time (t + h) depends on the average discovery size of some previous time t. For purposes of estimation we must choose some interval of time (which we shall call the "reference period") for which we can make observations of changes in discovery size. We will use the two-year interval immediately preceding the middle of the previous year's observation. The reference value of discovery size will therefore be the average of sizes over the past three years. We thus define

$$SZG_{REF} = (SZG_{-1} + SZG_{-2} + SZG_{-3})/3 \qquad (4)$$

and

$$SZO_{REF} = (SZO_{-1} + SZO_{-2} + SZO_{-3})/3 \qquad (5)$$

for natural gas and oil respectively. Consistent with this, the appropriate variable to be used in place of WXS[t, t+h] would be an index of the number of successful wells drilled from the reference period through the end of the previous year. The number of successful gas wells drilled from the middle of the reference period to date can be approximated by $(1/2)WXG_{-3} + WXG_{-2} + (1/2)WXG_{-1}$. We therefore define the following indices (proportioned only for numerical convenience):

$$WXG_{REF} = (WXG_{-1} + 2WXG_{-2} + WXG_{-3})/40 \qquad (6)$$

$$WXO_{REF} = (WXO_{-1} + 2WXO_{-2} + WXO_{-3})/40 \quad . \qquad (7)$$

Since the theoretical specification includes expected gas and oil prices, we will again use three-year moving averages of these prices as explanatory variables (the three-year period also corresponding to the time interval in the reference period). We thus obtain the following estimating equations for the size of gas discoveries and size of oil discoveries:

$$\log(SZG) = \log(SZG_{REF}) +$$
$$WXG_{REF}\cdot f_1(DEPG_{-1}, (PG_{-1}+PG_{-2}+PG_{-3})/3, (PO_{-1}+PO_{-2}+PO_{-3})/3) \qquad (8)$$

$$\log(SZO) = \log(SZO_{REF}) +$$
$$WXO_{REF}\cdot f_2(DEPO_{-1}, (PG_{-1}+PG_{-2}+PG_{-3})/3, (PO_{-1}+PO_{-2}+PO_{-3})/3) \quad . \qquad (9)$$

The theoretical specification for the success ratio equations appears in equation (22) of Section 3.2.4, and applying the same notion of a reference period we obtain the following equations for the gas and oil success ratios:

$$\log(SRG) = \log(SRG_{REF}) + WXG_{REF} \cdot f_3(\sum_1^3 PG_{-i}, \sum_1^3 PO_{-i}) \tag{10}$$

$$\log(SRO) = \log(SRO_{REF}) + WXO_{REF} \cdot f_4(\sum_1^3 PG_{-i}, \sum_1^3 PO_{-i}) \tag{11}$$

where SRG_{REF} and SRO_{REF} are defined by

$$SRG_{REF} = ((SRG_{-1} + SRG_{-2} + SRG_{-3})/3) \cdot \frac{S\hat{Z}G}{S\hat{Z}G_{REF}} \tag{12}$$

$$SRO_{REF} = ((SRO_{-1} + SRO_{-2} + SRO_{-3})/3) \cdot \frac{S\hat{Z}O}{S\hat{Z}O_{REF}} . \tag{13}$$

One problem with equations (10) and (11) is that they provide no guarantee that the estimated success ratios will take on values between 0 and 1. In order to constrain the success ratios to the interval (0,1), we will use the following logit specification for our estimating equations:

$$\log\left(\frac{SRG}{1 - SRG}\right) = \log\left(\frac{SRG_{REF}}{1 - SRG_{REF}}\right) + WXG_{REF} \cdot f_3(\sum_1^3 PG_{-i}, \sum_1^3 PO_{-i}) \tag{14}$$

$$\log\left(\frac{SRO}{1 - SRO}\right) = \log\left(\frac{SRO_{REF}}{1 - SRO_{REF}}\right) + WXO_{REF} \cdot f_4(\sum_1^3 PG_{-i}, \sum_1^3 PO_{-i}) . \tag{15}$$

It is important to stress that equations (3), (8), (9), (14), and (15) must be estimated in sequential order. First, the size equations (8) and (9) are estimated and the resulting equations are used to generate size estimates for the reference variables in the success ratio equations. In addition, the estimated standard errors of the size equations will be used in the estimation of the wells equation. Equations (14) and (15) for the success ratios are estimated next, and the results are used to generate estimated success ratios. Finally, the wells equation can be estimated, using estimated sizes, estimated success ratios, and the estimated ratio $(\hat{\sigma}_0^2/\hat{\sigma}_G^2)$.

These equations are estimated by pooling data from eighteen FPC production districts over the years 1964 through 1972. No data prior to 1964 was used to ensure that the estimation period included only those years for which regulation was effective (i.e., for which excess demand existed in reserves markets). Equations were estimated using the generalized least squares procedure discussed above, except that the serial correlation coefficient was assumed to be the same in all regions.[14]

The estimated versions of the five equations that determine new discoveries of natural gas and oil are shown below, with t-statistics in parentheses. Note that these estimation results, and the associated statistics, refer to the <u>last stage</u> of our generalized least squares procedure.

---

[14]Because these reserves equations contain variables with lags up to three years, only five years of data can actually be used in the estimation (nine years are initially available, but three are lost because of lags and one because of the autoregressive transformation). It was felt that region-by-region estimates of ρ_j based on five data points would have unacceptably large variances.

Exploratory Wells:

$$WXT = \underset{(6.01)}{796.16} - \underset{(-0.03)}{20.74}DD1 + \underset{(2.61)}{294.12}DD2 - \underset{(-0.02)}{1.49}DD3 + \underset{(0.53)}{234.29}DD4$$

$$+ \underset{(7.074)}{0.00367}[\hat{SZG}\cdot\hat{SRG}(PG_{-1}+PG_{-2}+PG_{-3})/3 + \hat{SZO}\cdot\hat{SRO}\cdot((PO_{-1}+PO_{-2}+PO_{-3})/3]$$

$$- (\underset{(-2.49)}{2.04x10^{-8}} - \underset{(0.51)}{1.74x10^{-8}}DD1)[\hat{SZG}^2\cdot\hat{SRG}^2((PG_{-1}+PG_{-2}+PG_{-3})/3)^2$$

$$+ \frac{\sigma_0^2}{\sigma_G^2}\cdot\hat{SZO}^2\cdot\hat{SRO}^2\cdot((PO_{-1}+PO_{-2}+PO_{-3})/3)^2] - \underset{(-1.36)}{0.00204}ATCM - \underset{(-5.85)}{64.15}INTA_{-1} \quad (16)$$

$R^2 = 0.81$ $F = 20.84$ S.E. = 1.781 D.W. = 1.52

where[15]

$$\frac{\sigma_0^2}{\sigma_G^2} = \frac{(\text{S.E. of SZO regression})^2/(\text{Average value of WXG})}{(\text{S.E. of SZG regression})^2/(\text{Average value of WXO})}$$

$$= \frac{(5.46)^2}{(3.52)^2}\cdot\frac{1}{2.38} = 1.01$$

Size of Gas Discoveries (For Successful Gas Wells):

$$\frac{1}{WXG_{REG}}\log\left(\frac{SZG}{SZG_{REF}}\right) = \underset{(-1.21)}{-0.0717} + \underset{(1.92)}{0.02687}DD1 + \underset{(1.53)}{0.0638}DD2 + \underset{(0.0255)}{0.03825}DD3$$

$$+ \underset{(1.60)}{0.1146}DEPG_{-1} + \underset{(1.21)}{0.00285}((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$- \underset{(-0.95)}{0.0241}((PO_{-1} + PO_{-2} + PO_{-3})/3) \quad (17)$$

$R^2 = 0.95$ $F = 295.6$ S.E. = 3.519 D.W. = 1.68

---

[15] Estimated error variances are divided by average values of the number of successful gas and oil wells to account for the heteroscedasticity correction used in the estimation of the size equations.

where

SZG_{REF} = size of gas discoveries in the reference period immediately preceding the current period

$$= (SZG_{-1} + SZG_{-2} + SZG_{-3})/3$$

WXG_{REF} = index of number of successful gas wells completed in the reference period immediately preceding the current period

$$= (WXG_{-1} + 2WXG_{-2} + WXG_{-3})/40$$

Size of Oil Discoveries (For Successful Oil Wells):

$$\frac{1}{WXO_{REF}} \log\left(\frac{SZO}{SZO_{REF}}\right) = \underset{(-1.10)}{-0.08228} + \underset{(1.22)}{0.02074DD1} + \underset{(0.66)}{0.00464DD2} + \underset{(0.37)}{0.00233DD3}$$

$$+ \underset{(0.35)}{0.02820DEPO_{-1}} - \underset{(-2.08)}{0.00195}((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$+ \underset{(2.37)}{0.02932}((PO_{-1} + PO_{-2} + PO_{-3})/3) \qquad (18)$$

$R^2 = 0.84$ F = 55.92 S.E. = 5.46 D.W. = 1.68

where

SZO_{REF} = size of oil discoveries in the reference period immediately preceding the current period

$$= (SZO_{-1} + SZO_{-2} + SZO_{-3})/3$$

WXO_{REF} = index of number of successful oil wells completed in the district in the reference period immediately preceding the current period

Fraction of Successful Gas Wells:

$$\log\left(\frac{SRG}{1-SRG}\right) = \log\left(\frac{SRG_{REF}}{1-SRG_{REF}}\right) + WXG_{REF}[\underset{(-0.902)}{-0.04653} - \underset{(-2.60)}{0.02706DD1} - \underset{(-1.88)}{0.02502DD2}$$

$$- \underset{(-2.382)}{0.02891DD3} - \underset{(-2.21)}{0.00312}((PG_{-1}+PG_{-2}+PG_{-3})/3)$$

$$+ \underset{(2.14)}{0.04384}((PO_{-1} + PO_{-2} + PO_{-3})/3)] \qquad (19)$$

$R^2 = 0.76$ F = 55.59 S.E. = 4.32 D.W. = 1.61

where

$$SRG_{REF} = ((SRG_{-1} + SRG_{-2} + SRG_{-3})/3)\ \frac{S\hat{Z}G}{S\hat{Z}G_{REF}}$$

Fraction of Successful Oil Wells:

$$\log \frac{SRO}{1-SRO} = \log \frac{SRO_{REF}}{1-SRO_{REF}} + WXO_{REF}[\underset{(0.98)}{0.05521} + \underset{(1.09)}{0.02815}DD1 + \underset{(0.73)}{0.02571}DD2 + \underset{(0.69)}{0.0138}DD3$$

$$+ \underset{(0.80)}{0.00208}((PG_{-1} + PG_{-2} + PG_{-3})/3)$$

$$- \underset{(-1.27)}{0.0378}((PO_{-1} + PO_{-2} + PO_{-3})/3)] \qquad (20)$$

$R^2 = 0.43$ F = 2.88 S.E. = 3.7 D.W. = 1.48

where

$$SRO_{REF} = ((SRO_{-1} + SRO_{-2} + SRO_{-3})/3)\ \frac{S\hat{Z}O}{S\hat{Z}O_{REF}}$$

The estimated equations follow the theory fairly closely. Although some of the explanatory variables are not statistically significant, the signs of all the coefficients are consistent with our expectations. For example, in equation (16) expected return appears with a positive coefficient while expected risk, drilling costs, and the interest rate all appear with negative coefficients as expected. The positive coefficients of the depletion variable in the size equations are also correct, since this index decreases in size as depletion ensues. Finally, in both the size equations and success ratio equations the price coefficients for gas and oil prices appear with opposite signs, as expected if there is directionality in oil and gas drilling.

These equations provide us with an important empirical result, namely that as field prices of natural gas increase, additional drilling is done on average on the <u>extensive</u> margin. The size of gas discoveries per successful well increases (from equation (17)), while the success ratio for gas wells decreases (from equation (19)), indicating that additional drilling has been undertaken in regions with lower probabilities of success but higher size of finds. Changes in the price of oil also have resulted in additional drilling directed on the whole towards the extensive margin, generally with the size of oil discoveries increasing and the success ratio for oil wells decreasing as oil prices increase.

The results also relate to the question of whether there has been "directional drilling". Increases in the price of gas seem to result in an increase in the success ratio for oil wells, and a decrease in the size of oil discoveries. This indicates that as gas becomes more profitable relative to oil, producers shift to more extensive exploration for gas and more intensive exploration for oil. This does not mean, however, that oil discoveries go down; in fact they may increase since the total amount of drilling activity is increasing. Finally, an increase in the price of oil, while resulting in more oil discoveries, will also result in some additional gas discoveries (both because the total amount of drilling has increased and because associated gas is found with the oil).

4.3.2. Estimated Equations for Extensions and Revisions

There is little economic explanation for extensions and revisions. We expect extensions of both natural gas and oil to depend on lagged discoveries and the number of exploratory wells drilled in the previous years. Equations were estimated in linear form using these explanatory variables, as shown below.

Natural Gas Extensions:

$$\underset{(-0.34)}{XG = -38213} + \underset{(2.72)}{1.1307\text{x}10^6 DD1} + \underset{(6.18)}{1.9595\text{x}10^6 DD2} + \underset{(0.11)}{16080.9DD3} + \underset{(2.38)}{0.2942DG_{-1}} + \underset{(2.17)}{440.2WXT_{-1}} \qquad (21)$$

$R^2 = 0.44$ $F = 22.05$ $S.E. = 2.87\text{x}10^5$ $D.W. = 1.84$

Oil Extensions:

$$\underset{(0.79)}{XO = 4096.0} + \underset{(10.31)}{1.7852\text{x}10^5 DD1} + \underset{(3.06)}{44092.7DD2} - \underset{(-0.81)}{5192.7DD3} + \underset{(0.93)}{0.0924DO_{-1}} + \underset{(2.86)}{33.928WXT_{-1}} \qquad (22)$$

$R^2 = 0.69$ $F = 50.80$ $S.E. = 1.9\text{x}10^4$ $D.W. = 1.90$

Alternative forms for these equations were estimated to determine whether the depletion variables and prices would offer any additional explanatory power. Alternative regression equations for extensions of natural gas are shown in equation (23), which includes the depletion variable and total reserves, and equation (24), which includes the gas price.

$$XG = \underset{(0.72)}{1.85\text{x}10^5} + \underset{(2.40)}{2.15\text{x}10^6 DD1} + \underset{(5.81)}{2.16\text{x}10^6 DD2} + \underset{(0.91)}{1.69\text{x}10^5 DD3}$$

$$+ \underset{(2.64)}{0.315PG_{-1}} + \underset{(2.41)}{463.75WXT_{-1}} - \underset{(-0.74)}{2.7\text{x}10^5 DEPG_{-1}} - \underset{(-1.25)}{0.015YG_{-1}} \qquad (23)$$

$R^2 = 0.45$ $F = 18.2$ $S.E. = 2.73\text{x}10^5$ $D.W. = 1.85$

$$XG = \underset{(0.64)}{2.02\text{x}10^6} + \underset{(2.94)}{1.18\text{x}10^6 DD1} + \underset{(5.76)}{1.92\text{x}10^6 DD2} - \underset{(-0.04)}{6412.0DD3}$$

$$+ \underset{(2.41)}{0.289DG_{-1}} + \underset{(2.06)}{409.0WXT_{-1}} - \underset{(-0.30)}{1.04\text{x}10^5 DEPG_{-1}} - \underset{(-0.87)}{8490.0PG_{-1}} \qquad (24)$$

$R^2 = 0.46$ $F = 17.5$ $S.E. = 2.8\text{x}10^5$ $D.W. = 1.82$

The reserves, the depletion variable, and the price variable are statistically insignificant and appear with the wrong signs.

Alternative regressions for extensions of oil reserves are shown in equations (25) and (26).

$$XO = \underset{(-1.24)}{-15853.0} + \underset{(8.58)}{1.56x10^5 DD1} + \underset{(0.14)}{2989.6DD2} - \underset{(-0.65)}{3593.9DD3}$$

$$+ \underset{(1.02)}{0.105DO_{-1}} + \underset{(2.89)}{30.52WXT_{-1}} + \underset{(1.31)}{21447.0DEPO_{-1}} + \underset{(2.44)}{0.0065YO_{-1}} \tag{25}$$

$R^2 = 0.76$ F = 51.4 S.E. = $1.88x10^4$ D.W. = 1.81

$$XO = \underset{(1.38)}{33743.0} + \underset{(10.78)}{1.85x10^5 DD1} + \underset{(3.45)}{45438.0DD2} - \underset{(-0.48)}{2908.3DD3}$$

$$+ \underset{(0.95)}{0.098DO_{-1}} + \underset{(2.30)}{26.72WXT_{-1}} + \underset{(0.49)}{8065.0DEPO_{-1}} - \underset{(-1.68)}{10748.0PO_{-1}} \tag{26}$$

$R^2 = 0.74$ F = 44.8 S.E. = $1.9x10^4$ D.W. = 1.84

Here again the price variable appears with the wrong sign, and the depletion variable is insignificant.

Revisions of natural gas and oil reserves tend to defy economic reasoning as well. We expected that explanatory variables would include past year-end reserves, changes in production, and the depletion index. When we actually estimated these equations, we found that all of the variables did offer some explanatory power in the oil equation, but changes in production were not significant in the gas equation. The final regression equations, again estimated in linear form, are shown below.

<u>Revisions of Natural Gas Reserves</u>:

$$RG = \underset{(-2.42)}{-71295} + \underset{(3.21)}{0.02007YG_{-1}} + \underset{(0.52)}{0.3142\Delta(QG_{-1})} + \underset{(2.07)}{930610DEPG_{-1}} \tag{27}$$

$R^2 = 0.14$ F = 7.3 S.E. = $5x10^5$ D.W. = 1.98

<u>Revisions of Oil Reserves</u>:

$$RO = \underset{(-2.38)}{-13345} + \underset{(5.80)}{0.0483YO_{-1}} + \underset{(2.92)}{3.501\Delta(QO_{-1})} + \underset{(2.33)}{188210DEPO_{-1}} \tag{28}$$

$R^2 = 0.56$ F = 28.3 S.E. = $1.02x10^5$ D.W. = 1.75

Note that the equation for revisions of natural gas reserves has a rather poor statistical fit, with an R^2 of 0.14 and a standard error that is about five times the mean value of the dependent variable. We were unable to obtain a regression equation any better than (27), and we must simply recognize that natural gas revisions are likely to provide a large amount of noise in simulation.

4.4. Estimated Equations for Production of Gas

The structural equations for gas production depend on specification of the marginal costs of developing existing reserves, which in turn depend on the particular functional form that one chooses to represent development investment. Using different development investment functions, we arrived at alternative estimating equations for gas production that would apply under marginal cost pricing, as in equations (35), (36), and (41) in Section 3.3. We derived other alternative structural equations, as given by (43), (44), and (45), that would apply for deviations from marginal cost pricing resulting from non-competitive market structures.

In estimation we have been faced with the problems of choosing among the equation forms, deciding whether or not to include the "competition" variable that accounts for deviations from marginal cost pricing, and selecting a set of regional breakdowns most appropriate for the estimations. All six equations (i.e., the three alternative equation forms, each with and without the competition variable) were estimated over different regional breakdowns. Price elasticities were calculated, and the equations were simulated historically to determine how well they tracked past data. The results indicated that equation (36) would provide the best fit, both in estimation and simulation, and that the competition variable should not be included, indicating that marginal cost pricing would apply.

Before discussing regional breakdowns, let us consider the regression results for alternative equation forms with and without the competition variable. A representative set of alternative regressions is shown in Table 4.1. As can be seen in that table, the competition variable is statistically insignificant, except in equation (D); but at the same time the reserve variable appears with an incorrect sign in this regression so that it is unacceptable. Equation (35) from Section 3.3 is represented by regression C, and again the reserve variable appears with the wrong sign. Equation (41) is represented by regression A, but the estimated discount rate in that regression is negative (it should have a value close to 0.1).

Regressions E through K are all based on equation (36), i.e., on

$$Q = \alpha_0 + \alpha_1 \log PW + \alpha_2 YG_{-1}$$

They differ from each other in that different additive and multiplicative dummy variables are used as a means of ascertaining the appropriate regional breakdown.[16] Estimations using alternative regional breakdowns gave equally statistically significant results in most cases, and the choice of one regional breakdown over another was based more on whether the equations tracked the historic data closely in all production districts.

When the equation was estimated for the entire United States, excluding Louisiana South, the general fit was acceptable, but in simulation of historical production the equation failed to reproduce behavior accurately in the Permian region. The equation was estimated again using alternative dummy variable specifications (regressions H, I, and J), but again the results failed to track production behavior realistically in particular districts. The problem here is that districts which are fairly homogeneous in their production behavior tend to

[16] A highly significant dummy variable for a region or group of regions that accounts for a sizable part of the explained variance in an equation is indicative that the region(s) might be included in a separate equation.

Table 4.2 Production Equations - Alternate Forms

	Regions Pooled	Time Period	R-Sq.	St Er.	Const.	log(PW)	YT(-1)	YT	YTlog(PW)	YTlog(YT/PW)	Competition	L.S Intercept Dummy	Permian Intercept Dummy	MidCont. Intercept Dummy	Permian Price Dummy	MidCont. Price Dummy	Permian Reserves Dummy	MidCont. Reserves Dummy
A.	US Total	1961-71	0.33	0.63	$1.5x10^4$ (0.12)			0.32 (3.7)		-0.02 (-3.7)		$5.8x10^7$ (9.1)	$1.6x10^7$ (3.7)	$3.3x10^6$ (5.5)				
B.	US Total	1961-71	0.33	0.55	$1.0x10^6$ (0.9)			0.32 (3.6)		-0.02 (-3.5)	$-2.4x10^7$ (-0.1)	$5.7x10^7$ (8.9)	$1.7x10^7$ (3.8)	$3.0x10^6$ (4.6)				
C.	US Total	1961-71	0.93	0.54	$6.0x10^5$ (11.3)			-0.02 (-3.24)	0.03 (10.5)			$5.3x10^7$ (8.5)	$2.6x10^6$ (4.1)	$-5.8x10^5$ (-4.4)				
D.	US Total	1961-71	0.95	0.54	$1.6x10^5$ (7.1)			-0.03 (-4.1)	0.03 (11.4)		$-2.7x10^6$ (-4.4)	$5.3x10^7$ (8.7)	$2.7x10^6$ (4.4)	$-6.7x10^5$ (-5.4)				
E.	US Total	1961-71	0.32	0.63		-0.01 (-1.5)	0.3 (3.6)					$5.8x10^7$ (8.9)	$1.6x10^7$ (3.6)	$3.1x10^6$ (5.0)				
F.	US Total	1961-71	0.32	0.44		-0.01 (-1.6)	0.4 (4.0)				$-3.2x10^7$ (-1.3)	$5.8x10^7$ (8.8)	$1.7x10^7$ (3.8)	$2.7x10^6$ (4.0)				
G.	US Except La. South	1961-71	0.96	0.76	$-2.0x10^3$ (-0.04)	$2.0x10^3$ (1.39)	0.059 (32.8)											
H.	US Except La. South	1961-71	0.89	0.71	$5.1x10^5$ (1.59)	$4.0x10^3$ (0.39)	0.057 (18.5)						$1.2x10^7$ (2.37)	$3.7x10^5$ (1.03)				
I.	US Except La. South	1961-71	0.97	0.69	$-2.1x10^5$ (-0.51)	$2.6x10^5$ (1.94)	0.060 (34.8)								$3.2x10^6$ (4.50)	$-2.1x10^5$ (-1.42)	-0.039 (-2.05)	0.008 (1.59)
J.	US Except La. South	1961-71	0.97	0.53	$-2.6x10^5$ (-0.58)	$2.4x10^5$ (1.09)	0.060 (33.4)				$3.2x10^5$ (0.33)				$3.2x10^6$ (4.50)	$-2.0x10^5$ (-1.42)	-0.030 (-2.05)	0.008 (1.57
K.	MidCont and L.South On Permian	1963-71	0.92	0.72	$-6.9x10^5$ (-1.39)	$5.6x10^5$ (3.14)	0.023 (6.59)					$5.8x10^5$* (7.14)	$2.6x10^7$ (2.92)					

*La. South onshore portion only included here.

fall in regional groups, but production behavior is quite different between groups--so much so that the heterogeneities cannot be captured with only a few dummy variables.

As a result, production out of reserves equations have been estimated separately for four different regions in the country. The regional breakdown is as follows:

1. Permian (New Mexico South, Texas 7C, 8, 8A)
2. Gulf Coast and Mid-Continent (Kansas, Louisiana South onshore, Oklahoma, Texas 1, 2, 3, 4, 10)
3. Other Continental (Colorado plus Utah, Louisiana North, Missouri, Mississippi, New Mexico North, Pennsylvania, Texas 6, Texas 9, West Virginia plus Kentucky, Wyoming)
4. Louisiana South offshore

Regression results for the three continental production regions are shown below (the production equation for offshore Louisiana is discussed in the next section, where we examine the empirical results for the entire offshore "submodel"). The equations for Gulf Coast - Mid-Continent and Other Continental were estimated using the generalized least squares procedure, and the estimated regional serial correlation coefficients and error term standard deviations are shown. Prices have been roughly the same in the four districts comprising the Permian Region, so that these districts were aggregated and a simple time series regression was run for the Permian Region. The equation was estimated, however, using a second-order serial correlation correction, and the two estimated serial correlation coefficients are shown.[17]

---

[17]The second-order correction assumes that the error terms are of the form

$$\varepsilon_{j,t} = \rho_1\varepsilon_{j,t-1} + \rho_2\varepsilon_{j,t-2} + \varepsilon^*_{j,t} \quad .$$

Permian:

$$QG = -6447700. + 1856700. \log (PW) + 0.1226\ YG_{t-2} \qquad (29)$$
$$\quad (-2.35) \qquad (1.67) \qquad (5.24)$$

$R^2 = 0.925$ $\quad F = 67.7$ $\quad S.E. = 1.42x10^5$ $\quad D.W.(0) = 1.98$

LHS MEAN = $1.73x10^6$

$\hat{\rho}_1 = 0.990$ $\quad \hat{\rho}_2 = -0.822$

Gulf Coast and Mid-Continent:

$$QG = -169420. + 5881360.\ LX + 340752. \log (PW) + 0.02638 YG_{t-1} \qquad (30)$$
$$\quad (-0.352) \qquad (6.95) \qquad (2.00) \qquad (6.78)$$

$R^2 = 0.906$ $\quad F = 193.7$ $\quad S.E. = 0.727$ $\quad D.W.(7) = 0.90$

LHS MEAN = 2.655

	$\hat{\rho}_j$	$\hat{\sigma}_j$
KA	0.6402	111834.
LX	0.9270	237533.
OK	0.8175	149732.
T1	0.9319	93124.
T2	0.9900	89984.
T3	0.8359	117108.
T4	0.6161	81681.
TO	0.7126	88510.

Remaining Continental Production:

$$QG = -9424.0 + 23034 \log (PW) + 0.05999 YG_{t-1} \qquad (31)$$
$$\quad (-0.22) \qquad (1.65) \qquad (29.23)$$

$R^2 = 0.968$ $\quad F = 1174.2$ $\quad S.E. = 0.785$ $\quad D.W.(9) = 1.00$

LHS MEAN = 5.21

	$\hat{\rho}_j$	$\hat{\sigma}_j$
COUT	0.3932	43182.4
LN	0.7749	52688.1
MO	0.9900	13369.8
MS	0.5279	14590.5
NN	0.6943	31432.6
PA	0.6970	26713.4
T6	0.2684	23185.6
T9	-0.0365	24564.4
WK	0.3580	18731.3
WY	0.7456	25310.

These equations are all quite significant. Although they seem in general to provide no better statistical fit than the alternative forms E through K in Table 4.1, they do perform considerably better in a simulation context, and are able to reproduce production behavior in virtually every production district in the country.[18]

---

[18] Note that the average field price PW is based on a "roll-in" of changing contract prices, and thus is explained by last year's average wellhead price, the new contract price (PG), and production (QG). The average wellhead price is defined as follows:

Average wellhead price = (new contract price x new production + average wellhead price on old contracts x production on old contracts)/total production

New Production = (this year's production - last year's production) + last year's production x depletion rate

If one assumes that the average wellhead price on old contracts equals last year's average wellhead price, then one obtains an estimate of the depletion rate (d) from the following equation (estimated over 18 FPC production districts from 1967 to 1971):

$$PW_t = [PG_t \cdot (QG_t - (1 - \underset{(7.07)}{.1557})QG_{t-1}) + PW_{t-1} \cdot QG_{t-1} \cdot (1 - \underset{(7.07)}{.1557})]/QG_t$$

$R^2 = .967$ S.E. = 0.707 F = 2667

This equation is the basis for calculating rolled-in prices in all onshore regions.

4.5. Estimated Equations for Offshore Reserves and Production

All of the equations in the offshore model are estimated using pure time-series data, since there is only one district involved. Because a longer time series is available for each variable (the 15 years 1958 through 1972) than is the case onshore, and because significant autocorrelation is expected in the estimated residuals, a second-order serial correlation correction is used as opposed to the first-order correction used in other parts of the natural gas model. The error term is assumed to be of the form:

$$\varepsilon_t = \rho_1 \varepsilon_{t-1} + \rho_2 \varepsilon_{t-2} + \varepsilon_t^*$$

where ε_t^* is the uncorrelated term.

In equations where right hand side variables are predetermined, a simple search procedure can be used to choose ρ_1 and ρ_2 to minimize the sum of squared residuals of the regression.[19] In equations where unlagged endogenous variables appear on the right-hand side, a two-stage least squares procedure must be combined with the second-order serial correlation correction. This is done using a procedure suggested by Fair, and it accounts for simultaneous equation bias as well as serial correlation bias.[20]

The available data for wildcat wells (WWT) aggregates those drilled for oil and for gas, so that the number of wells drilled should be responsive to changes in both the price of oil and the price of gas. It was not possible, however, to estimate a wells equation with both oil and gas prices as independent variables because these prices are highly collinear. Thus two gas-oil price indices are constructed, one each for the wells and discoveries equations,

[19] This is a modification of the Hildreth-Lu procedure.

[20] See R.C. Fair, [27].

and these are used in place of the two prices that would otherwise appear. The price index for the wells equation is constructed by first estimating that equation including the price of gas and excluding the price of oil. Next, the equation is re-estimated including the price of oil but excluding the price of gas. The coefficients of the oil and gas price terms are then used as weights in the price index. The price index for the discoveries equation is similarly calculated.[21]

The estimation results for the wells equation are shown below (with t-statistics in parentheses). The first two regressions are used only to generate the coefficients for the price index. The third regression, equation (34), is used to explain well drilling in the offshore model. The estimated values of the two serial correlation coefficients ρ_1 and ρ_2 are also shown.

$$WWT_t = \underset{(-9.1)}{-2550.6} + \underset{(8.7)}{164.5}\ LOG(ACT_t + ACT_{t-1})/2 + \underset{(5.0)}{1210.0}\ PG_{t-1} \quad (32)$$

$$WWT_t = \underset{(-9.0)}{-2522.2} + \underset{(9.5)}{156.7}\ LOG(ACT_t + ACT_{t-1})/2 + \underset{(2.3)}{106.4}\ PWO_{t-1} \quad (33)$$

$$\begin{aligned} WWT_t = {} & \underset{(-6.9)}{-4333.4} + \underset{(9.9)}{162.8}\ LOG(ACT_t + ACT_{t-1})/2 \\ & \underset{(3.5)}{+323.0}\ LOG(1210.0\ PG_{t-1} + 106.4\ PWO_{t-1}) \end{aligned} \quad (34)$$

$R^2 = .944$ S.E. = 23.0 F(2/12) = 101.0

$\hat{\rho}_1 = 0.737$ $\hat{\rho}_2 = -0.996$ LHS Mean = 134.6

All of the coefficients of equation (34) are statistically significant and have the expected signs.

---

[21] For a more detailed discussion of the statistical problems involved in estimating these equations, as well as the other equations of the offshore model, see P.N. Sussman [83].

The estimation results for new discoveries per well are shown below, and again the first two regressions are used to create the price index for the final equation. Note that in this equation price variables include the new contract price of gas and the ratio of the gas price to the oil price. The price index thus applies to these two variables, and will differ from the price index used in the wells equation.

$$DG_t/WWT_t = \underset{(1.3)}{5694.0} - \underset{(-3.5)}{2161.3}\ LOG(CWWT_{t-1}) + \underset{(3.4)}{68967}\ PG_t \tag{35}$$

$$DG_t/WWT_t = \underset{(-0.33)}{-1822} - \underset{(-3.6)}{2028.8}\ LOG(CWWT_{t-1}) + \underset{(3.8)}{3.2x10^5}\ PG_t/PWO_t \tag{36}$$

$$DG_t/WWT_t = \underset{(-3.6)}{2.0x10^5} - \underset{(-3.8)}{2092.1}\ LOG(CWWT_{t-1})$$

$$+ \underset{(3.8)}{20895.7}\ LOG(68967\ PG_t + 3.2x10^5\ PG_t/PWO_t) \tag{37}$$

$R^2 = .813$ S.E. $= 3.63x10^3$ $F(2/11) = 23.9$ D.W. $= 2.66$

$\rho_1 = -0.029$ $\rho_2 = -1.00$ LHS Mean $= 7.63x10^3$

All of the coefficients in equation (37), the final regression, are statistically significant. The positive coefficient on the price index in this equation describes the extensive mode in which drillers operate. The coefficients of the components of the price index indicate that an increase in the price of oil relative to the price of gas leads to more wildcats drilled for oil and less gas discoveries per wildcat drilled.[22]

Extensions and revisions of gas reserves are explained by a simple linear relationship, with the explanatory variables the number of field wells drilled (FWT) and the number of producing acres (ACP) in the previous year:

$$XRG_t = \underset{(-5.1)}{-1.66x10^6} + \underset{(7.5)}{4515.9}\ FWT_t + \underset{(2.5)}{0.405}\ ACP_{t-1} \tag{38}$$

$R^2 = .942$ S.E. $= 5.0x10^5$ $F(2/12) = 96.7$ D.W. $= 2.19$

$\hat{\rho}_1 = -0.625$ $\hat{\rho}_2 = -0.557$ LHS Mean $= 1.80x10^6$

---

[22] For a discussion of oil and gas directionality see Khazzoom, J.D. [43].

The equation describing field wells is a linear relationship between that variable and the number of offshore drilling rigs DRO and the long-term interest rate INT:

$$FWT_t = \underset{(1.2)}{113.6} + \underset{(7.0)}{8.3}\, DRO_t - \underset{(-1.5)}{21.0}\, INT_t \tag{39}$$

RSQ = .821   SER = 72.2   F(2/12) = 31.8   D.W. = 1.87

$\hat{\rho}_1 = 0.073$ $\hat{\rho}_2 = -0.140$ LHS Mean = 623.0

Here, field wells include all offshore wells except wildcat wells, i.e., they include development wells and exploratory extension wells. The coefficient on the drilling rig term (8.3) is consistent with empirical estimates of the average number of rig-days it takes to drill an offshore well (35-40).[23]

Production of gas out of reserves (QG) is explained by the average well-head price of gas (PWG) and total reserves (YT).[24] The functional form is the same as that for onshore, except that the reserve term contains a three-year lag (as explained in Section 3.4, we could expect this longer lag offshore).

$$QG_t = \underset{(4.5)}{3.4\text{x}10^6} + \underset{(5.1)}{2.3\text{x}10^6}\, LOG(PWG_t) + \underset{(32.2)}{0.116}\, YT_{t-3} \tag{40}$$

$R^2 = .992$ S.E. = $9.0\text{x}10^4$ F(2/11) = 727.9   D.W. = 2.34

LHS Mean = $1.36\text{x}10^6$

---

[23]See Adelman, M.A. and Baughman, M. [1].

[24]The roll-in mechanism that determines the average wellhead price PWG is based on a different depreciation rate offshore than onshore. Because offshore development has been more recent, only a small percentage of contracts have expired in the past. Our estimated roll-in equation (based on data over 1956-1973) is:

$$PWG_t = [PT_t \cdot (QG_t - (1 - \underset{(0.70)}{.0207})QG_{t-1}) + PWG_{t-1} \cdot QG_{t-1} \cdot (1 - \underset{(0.70)}{.0207})]/QG_t$$

$R^2 = .945$ S.E. = .0094   F = 292.3

The estimated depreciation rate is incremented by .005 each year after 1973 for forecast purposes to account for future expiration of old contracts.

The estimated equation fits the data well, and has a standard error that is less than 8 percent of the mean value of the dependent variable.

Next, forfeited acreage (ACRD) is explained by the amount of acreage leased (ACR) five years previously and an average of the acreage under supervision (ACT) five and six years previously:

$$ACRD_t = \underset{(-2.3)}{-1.26\text{x}10^5} + \underset{(4.7)}{0.5}\, ACR_{t-5} + \underset{(4.7)}{.1}\, ((ACT_{t-5} + ACT_{t-6})/2) \qquad (41)$$

R^2 = .853 S.E. = $1.3\text{x}10^5$ F(2/10) = 29.1 D.W. = 1.90

$\hat{\rho}_1$ = -0.985 $\hat{\rho}_2$ = -0.111 LHS Mean = $2.24\text{x}10^5$

Finally, new producing acreage (ACPN) is explained by the amount of non-producing acreage (ACN) one and two years previously, the amount of new discoveries (DG) in the previous year, and the cumulative number of acres leased (CACR) since 1954:

$$ACPN_t = \underset{(1.8)}{27923} + \underset{(1.9)}{0.02}ACN_{t-2} + \underset{(4.4)}{.28}DG_{t-1}\, (ACN_{t-1}/CACR_t) \qquad (42)$$

R^2 = .92 S.E. = $3.2\text{x}10^4$ F(2/10) = 56.6 D.W. = 1.83

$\hat{\rho}_1$ = -0.006 $\hat{\rho}_2$ = -0.850 LHS Mean = $1.22\text{x}10^5$

As indicated in equation (42), an increase in non-producing acreage under supervision in the previous two years and in new discoveries in the previous year result in additions to producing acreage. This relationship is subject to a geological constraint which is represented by the cumulative acres variable. As more and more acreage is leased, discoveries are found increasingly on lands that are already productive and decreasingly on previously non-productive lands.

Total acreage (ACT), which is an explanatory variable in the wells equation, and producing acreage (ACP), which is an explanatory variable in the extensions and revisions equation, are now determined through identities. The annual increase in total acreage is simply equal to acreage leased (an exogenous policy variable) minus forfeited acreage. The annual increase in producing acreage is equal to new producing acreage minus forfeited producing acreage (which in turn is 20% of all forfeited acreage).

4.6. Estimated Equations for Pipeline Price Markup

Economic and regulatory conditions lead us to expect the pipeline price markup to wholesale buyers to depend on mileage, volumetric capacity of the pipeline, an interest rate, average annual sales, and the Herfindahl index.[25] Generalized least squares regressions for this structural relationship have been run on a sample over the time span 1963 to 1971 with 40 cross-sections, comprising a total of 360 observations. The dependent variable in all cases is the level of the price markup in cents per Mcf. Independent variables are mileage, capacity, sales, the Herfindahl Index, and the interest rate. Dummy variables on some states were necessary to explain gross variations in the markups of similar states that resulted from heterogeneities between states.

Regression results for the equation used in the model are shown below, with t-statistics in parentheses, together with the estimated serial correlation coefficients (ρ_j) and the estimated error standard deviations (σ_j) used in the GLS procedure:

$$\begin{aligned} \text{MARKUP} = {} & \underset{(14.43)}{9.528} + \underset{(17.15)}{0.00773\text{M}} - \underset{(-14.93)}{3.306\text{x}10^{-4}\text{V}} + \underset{(10.9)}{1.109\text{INTA}_{-2}} + \underset{(13.0)}{8.363\text{NV}} + \underset{(4.61)}{7.394\text{UT}} \\ & - \underset{(-9.28)}{9.64\text{CA}} + \underset{(5.80)}{7.384\text{OH}} - \underset{(-8.34)}{6.365\text{WY}} + \underset{(4.79)}{4.013\text{WV}} - \underset{(-7.05)}{5.475\text{CO}} - \underset{(-7.27)}{3.153\text{IL}} \\ & + \underset{(6.04)}{5.476\text{WI}} - \underset{(-3.12)}{3.932\text{FL}} \end{aligned} \tag{4.5}$$

$R^2 = 0.960$ F = 571.9 S.E. = 0.516 D.W.(0) = 1.97

---

[25] Many of the series for these variables were not directly available, and had to be constructed from primary data (e.g., FPC forms) or computed from other data series. Sources and methods of computation of data are shown in Section 4.2. above.

Region	$\hat{\rho}_j$	$\hat{\sigma}_j$
AL	0.529	3.977
AZ	0.582	2.984
AR	0.595	2.529
CA	0.437	3.162
CO	0.199	3.174
MD	0.433	4.509
FL	0.347	4.404
GA	0.570	5.125
ID	0.551	3.107
IL	-0.029	2.092
IN	0.836	2.084
IO	0.650	1.605
KS	-0.280	1.767
KY	0.556	2.768
LA	0.554	2.682
MI	0.403	1.182
MN	0.376	2.515
MS	0.554	2.138
MO	-0.317	2.317
NB	-0.547	3.814
NV	0.263	2.439
NE	0.873	5.207
NJ	0.623	2.705
NM	0.202	2.870
NY	0.498	3.128
NC	0.659	1.781
OH	0.332	4.520
OK	0.406	1.641
OR	0.979	2.785
PA	0.593	4.095
SC	0.751	4.030
SD	-0.137	3.213
TN	0.495	3.739
TX	0.671	1.854
UT	0.217	6.744
VA	0.454	4.076
WA	0.949	2.275
WV	-0.428	6.413
WI	0.586	2.003
WY	0.274	2.661

A number of alternative estimations were also performed, and they are shown in Table 4.3. As can be seen from that table (as well as in the final regression) the strongest variable is the mileage series, which in nearly every regression has a coefficient close to .01 and a t-statistic of about 20. Assuming effective regulation, so that markups reflect only costs, this indicates an average total cost of roughly one cent per Mcf per hundred miles. The capacity, sales, and interest

TABLE 4.3. ALTERNATIVE REGRESSION EQUATIONS FOR THE PIPELINE PRICE MARKUP

R^2	F	Constant	Miles	Capacity	Sales	Interest Rate	Herfin-dahl	CA	CO	FL	ID	IL	NV	NE	NJ	NC/SC	OH	PA	UT	WV	WI	WY
								Dummy Variables														
.9719	3648.	8.553 (22.99)	.0145 (22.85)	-1.33×10^{-4} (7.291)									21.00 (22.53)									
.9717	2709.	8.701 (24.11)	.0162 (24.37)	-7.26×10^{-5} (3.496)	-6.45×10^{-6} (4.383)								12.22 (18.45)									
.9172	695.7	7.053 (8.490)	.0120 (20.26)	-1.72×10^{-4} (6.8036)	-3.28×10^{-6} (4.012)	1.006** 7.409							3.087 (8.490)									
.9228	750.7	6.718 (8.156)	.0118 (20.20)	-1.58×10^{-4} (5.758)	-4.46×10^{-6} (5.479)	1.107** (8.200)							3.121 (7.745)									
.9576	698.4	5.161 (5.950)	.0123 (22.42)	-1.44×10^{-4} (5.861)	-3.87×10^{-6}* (5.148)	1.097** (9.243)	1.910 (2.401)	-6.132 (4.132)			4.779 (2.871)		7.189 (7.83)			-6.769 (5.573)			8.434 (4.222)			
.9452	441.8	.0407 (7.234)	.0119 (22.58)	-1.74×10^{-4} (7.094)	-4.96×10^{-6}* (5.792)	1.194** (10.26)	.9032 (1.187)	-5.053 (2.829)			4.656 (2.864)		7.146 (7.470)			-6.542 (5.788)	7.812 (6.555)	4.443 (2.252)	8.223 (4.316)			
.9553	445.0	5.776 (7.235)	.0124 (24.07)	-1.66×10^{-4} (7.154)	-5.54×10^{-6}* (6.896)	1.180** (10.68)	1.246 (1.708)	-4.634 (2.758)		-6.479 (5.100)	4.380 (2.835)		6.712 (7.446)	12.36 (1.630)		-7.068 (6.506)	7.796 (6.911)	4.266 (2.240)	8.062 (4.436)			
.9467	418.8	5.753 (7.129)	.0125 (24.08)	-1.67×10^{-4} (7.012)	-5.46×10^{-6}* (6.347)	1.188** (10.57)	1.148 (1.566)	-4.793 (2.691)		-6.511 (5.267)	4.390 (2.796)		6.692 (7.205)			-7.086 (6.496)	7.686 (6.540)	4.107 (2.160)	8.120 (4.426)			
.9463	451.0	6.434 (9.423)	.0124 (24.13)	-1.7×10^{-4} (7.136)	-5.65×10^{-6}* (6.618)	1.197** (10.64)		-4.606 (2.586)		-6.419 (5.144)	4.893 (3.175)		7.231 (8.362)			-6.569 (6.301)	7.837 (6.673)	3.865 (2.032)	8.561 (4.710)			
.9563	444.2	7.151 (10.94)	.0118 (22.29)	-2.12×10^{-4} (9.002)	-6.32×10^{-6}* 8.055	1.269** 12.28		-4.029 (2.486)		-6.606 (5.787)	4.182 (2.959)		6.627 (8.235)	12.36 (1.811)	-4.101 (3.066)	-6.924 (7.223)	8.567 (8.011)	4.255 (2.468)	7.694 (4.612)			-5.36 (6.67
.9135	832.0	8.102 (8.863)	.0086 (16.65)	-2.72×10^{-4} (9.908)		1.067** (7.142)							5.833 (10.03)									
.9280	672.9	7.815 (9.262)	.0090 (18.86)	-2.58×10^{-4} (10.11)		1.059** (7.710)		-9.314 (6.316)					9.227 (10.94)						8.879 (4.018)			
.9375	584.0	9.347 (11.62)	.0074 (15.36)	-3.42×10^{-4} (13.47)		1.133** 8.940		-9.304 (7.021)					8.618 10.86				7.857 (4.89)		7.531 (3.722)			-6.26 (6.74
.9531	569.8	9.413 (13.25)	.0078 (16.36)	-3.35×10^{-4} (14.12)		1.144** (10.47)		-9.779 (8.845)	-5.568 (6.609)			-3.260 (7.081)	8.208 11.76				7.267 (5.337)		7.304 (4.242)	3.880 (4.307)		-6.43 (7.76
.9603	527.0	9.770 (12.01)	.0076 (15.72)	-3.34×10^{-4} (14.51)		1.116** 10.95	-.39909 (.55167)	-9.645 (9.290)	-5.361 (6.655)	-3.865 (3.052)		-3.135 (7.195)	8.552 (11.63)				7.924 (5.812)		7.533 (4.634)	4.008 (4.773)	5.620 (5.936)	(7.87
.9671	910.6	6.476 (9.052)	.0119 (22.57)	-1.64×10^{-4} (7.301)	-4.26×10^{-6} (6.615)	1.116 (9.826)		-5.311 (3.362)			5.552 (3.464)		8.059 (10.23)	1.369 (1.427)		-5.861 (5.203)			9.022 (4.581)			
.9566	759.2	6.497 (8.880)	.0121 (22.29)	-1.62×10^{-4} (7.130)	-3.94×10^{-6} (5.560)	1.087 (9.179)		-5.789 (3.555)			5.583 (3.435)		8.039 (10.01)			-5.919 (5.178)			9.115 4.598			
.9604	571.8	9.528 (14.43)	.0077 (17.14)	-3.31×10^{-4} (14.93)		1.109** (10.94)		-9.642 (9.284)	-5.474 (7.050)	-3.931 (3.218)		-3.153 (7.272)	8.362 (13.00)				7.384 (5.797)		7.393 (4.609)	4.013 (4.788)	(5.476) (6.037)	-6.36 (8.34

(*Indicates a 1-year lag, **a two-year lag.)

variables are also strong in general, with t-statistics in the range of 4 to 10. The Herfindahl Index is the weakest variable in the model, and is usually statistically insignificant or appears with the wrong sign.

A preliminary historical simulation of the estimated equation without dummy variables showed that in several states the markup was severely under-or over-estimated. This variance was not correlated with geography. In the Carolinas, for example, wholesale prices seemed to be about 5¢ lower than in the neighboring states, while in Ohio they were about 5¢ higher. These variations could be the result of different tax structures in the two states of which we are not aware, or of degrees of competition not correlated with the Herfindahl Index. In any case, dummy variables are used for those states which show large initial simulation errors. Also, the final equation chosen for the model did not contain a sales term, because the "sales" variable includes interstate sales only. Since there is no way to separate interstate and intrastate sales in the demand equations of the model, a markup equation that included interstate sales only could not be simulated directly, so that this term had to be excluded. All of the explanatory variables and dummy variables in the final regression are statistically significant, and the equation simulates the historic data quite closely.

4.7. Estimated Equations for Wholesale Demand for Natural Gas

The structural equations for wholesale demands for gas, whether residential or industrial, explain the level of "new" demand, δQ, defined as

$$\delta Q_t = \Delta Q_t + rQ_{t-1} \qquad (44)$$

with r as a depreciation rate for gas-burning appliances. The gas wholesale demand equations, then, are of the form:

$$\delta Q = f(PGW, POIL, YY, \delta YY, \delta NN, \ldots) \qquad (45)$$

so that the level of new demand is related to the wholesale gas price, the price of competing fuels (such as oil), and "growth" variables such as income, population, etc.

Before this equation can be estimated, a value must be determined for the depreciation rate r.[26] An equation of the form:

$$Q_t = a_0 + a_1 PGW_t + a_2 POIL_t + a_3 YY_{t-1} + a_4 Q_{t-1} \qquad (46)$$

is estimated so as to provide the value of r equal to $(1 - a_4)$. After a series

---

[26] Balestra [8] distinguishes between two depreciations rates, one for gas appliances and the other for alternative fuel-burning appliances, since lifetime for appliances using alternative fuels differ. He estimates these two depreciation rates with an equation of the form:

$$Q_t = a_0 + a_1 PGW_t + a_2 \Delta NN_t + a_3 NN_{t-1} + a_4 \Delta YY_t + a_5 YY_{t-1} + a_6 Q_{t-1}$$

so that depreciation rate for gas appliances is given by $(1 - a_6)$. (His results, however, gave an estimated value of a_6 that was always greater than one, which cannot be justified theoretically.) The alternative fuels depreciation rate can be obtained from this equation as either the ratio a_3/a_2 or a_5/a_4. Thus, the equation is overidentified, so that the depreciation rate can be obtained only by estimating it subject to the constraint of $a_3/a_2 = a_5/a_4$. (The resulting estimation problem is nonlinear, but Balestra uses an iterative method suggested by Houthakker and Taylor [36] to obtain an estimated depreciation rate equal to 0.11, a number which seems somewhat high.) Our initial attempts to follow Belestra's approach failed to provide meaningful estimates of two separate depreciation rates.

of trials, we obtained a value of the depreciation rate equal to 0.07. This value is used here for both industrial and for residential/commercial demand in all parts of the country.

An earlier version of this econometric model[27] divided natural gas demand into three major categories, sales for resale, mainline sales, and intrastate sales, and then further subdivided sales for resale into residential/commercial demand and industrial demand. (The distinction between residential/commercial demand and industrial demand was not necessary for the other two major demand categories since mainline sales and intrastate sales are largely industrial.) After improving and extending our data base on wholesale consumption and prices, an attempt was made to estimate a new set of demand equations using this same breakdown. Representative estimation results for different regions of the country are shown in Table 4.4.

As can be seen, some of the regressions for sales for resale demand show credible results, but the mainline and intrastate demand equations are extremely poor, often producing negative R^2's.[28] Given these results, an alternative breakdown was made, based on the presumption that sales for resale industrial demand, mainline demand, and intrastate demand have roughly the same economic determinants, and that dividing industrial demand

[27] See P.W. MacAvoy and R.S. Pindyck, "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage", Bell Journal of Economics and Management Science, Autumn, 1973. The equations described in this article were estimated by two-stage least squares, however, and therefore are not directly comparable with the regression results presented in this section, where a generalized least squares procedure was used.

[28] It is possible to obtain a value of R^2 less than zero using our generalized least squares estimation procedure. See Section 4.1 for a detailed description of that procedure.

TABLE 4.4 GAS DEMAND REGRESSIONS

UNDER SALES-FOR-RESALE AND MAINLINE SALES PRODUCTION

Dependent Variables	Time Bounds	Region	R^2	S.E.	F	Const.	IP	MP	SP	POIL	PFOIL	δNN	VAM	PALT
1. δINTRA	66-71	U.S.	-0.042	.542	-0.35	2.7×10^5 (1.49)	-9.9×10^3 (-1.58)						3.36 (1.31)	8.3×10^3 (0.07)
2. δMS	64-71	U.S. Producers	-0.124	.547	-3.03	5.3×10^3 (2.76)		-36 (-0.46)		-2.7×10^3 (-1.25)			0.02 (0.33)	
3. δMS	64-71	U.S. Non-Producers	-0.311	.842	-8.54	4.9×10^3 (2.12)		-97 (-1.49)		-1.2×10^3 (-0.92)			0.06 (0.79)	
4. δRCS	63-71	NE	0.546	.736	24.0	-7.9×10^3 (-0.76)			-783 (-5.00)		3.4×10^3 (3.59)	45.6 (10.2)		
5. δRCS	63-71	NC	0.313	.857	10.3	3.5×10^4 (2.53)			-289 (-1.07)		-2.5×10^3 (-1.82)	59.2 (8.68)		
6. δRCS	63-71	SE	-0.054	.883	-0.88	-1.2×10^4 (-1.04)			-320 (-1.14)		2.6×10^3 (2.05)	2.78 (0.37)		
7. δRCS	63-71	SC	-0.148	.895	-1.90	-4.8×10^3 (-0.67)			-41 (-0.26)		808 (1.10)	-0.95 (-0.23)		
8. δRCS	63-71	W	-0.188	.981	-4.10	-7.2×10^3 (-4.20)			-43 (-2.20)		807 (4.72)	27.3 (9.54)		
9. δINS	63-71	NE	-0.097	.787	-1.78	2.3×10^4 (2.77)			-619 (-3.56)	1.1×10^4 (1.87)			1.02 (4.25)	
10. δINS	63-71	NC	0.426	.900	16.8	6.3×10^3 (1.34)			1.9 (0.01)	-9.0×10^3 (-1.91)			2.36 (13.8)	
11. δINS	63-71	SE	0.293	.839	7.17	3.0×10^4 (3.00)			-381 (-1.49)	-1.6×10^4 (-2.69)			1.50 (1.80)	
12. δINS	63-71	SC	0.043	.800	0.673	-332 (-0.05)			985 (0.05)	-729 (-0.16)			3.24 (5.83)	
13. δINS	63-71	W	0.359	.837	14.2	1.9×10^3 (2.86)			-4.5×10^3 (-2.64)	[illegible].3x10^3 ([illegible].78)			3.33 (11.2)	

up into these three categories was simply adding noise to the data through the process of disaggregation.[29] Industrial demand was aggregated from these three groups, so that further estimation was done on only industrial and residential/commercial sectors.

The two demand equations (one for residential/commercial demand, and the second for industrial demand) are estimated for each of the five wholesale regions of the country. The regression period was first chosen to be 1963 to 1971 for both the industrial and residential/commercial sectors, as this covered the period for which our data were most complete. In those regressions, price terms are unlagged in industrial equations under the assumption that industrial consumers can rapidly convert <u>new</u> demand to alternative energy sources, while price variables in the residential/commercial demand equations contain a one-year lag. Dummy variables are used selectively; in the North Central region, for example, dummy variables are used for states such as Illinois, Iowa and Wisconsin since these states use natural gas to generate electricity which is transported to neighboring states for final consumption. The results for these regressions are shown in Table 4.5.

Simulations of the regression equations in Table 4.5 indicated that industrial demand was being under-predicted in the years 1971 and 1972. The reason for this appeared to be that the equations were estimated using observations over the time in which there were curtailments of service to industry (after 1970) so that the industrial demand equations were re-estimated using only data from 1963 to 1969. The residential/commercial demand equations were also re-estimated, again over the period 1963 to 1971, but using alternative growth variables in an attempt to improve their simulation performance. All of these equations

---

[29] The division of sales for resale demand into industrial and residential/commercial sales was based on a ratio derived from Bureau of Mines consumption data.

Table 4.5. Alternative Wholesale Gas Demand Equations

Dependent Variable	Region	Time Bounds	R.Sq.	S.E.	F	Const.	TP_{-1}	TP	$PFOIL_{-1}$	$PALT_{-1}$	PALT	PCOAL	POIL	CAP_{-1}	VAM	δYM	δYY	Oh Dummy	Pa Dummy	Il Dummy	In Dummy	Io Dummy	Mn Dummy	Wi Dummy	Al Dummy	Fl Dummy	Ga Dummy	Ky Dummy	NC Dummy	SC Dummy	Tn Dummy	La Dummy	Ca Dummy	Nv Dummy
1. δTRCS	NE	63-71	0.901	.641	133	$2.2x10^5$ (2.31)	-721 (-5.62)		661 (1.10)							39.8 (12.3)		$2.9x10^5$ (3.23)																
2. δTRCS	NC	63-71	0.308	.690	4.83	$3.1x10^4$ (1.99)	$-1.0x10^3$ (-1.98)			$1.7x10^4$ (0.83)							8.76 (7.75)			$3.6x10^4$ (3.37)		$5.8x10^3$ (2.29)		$7.6x10^3$ (1.65)										
3. δTRCS	SE	63-71	0.334	.857	2.95		$-1.3x10^3$ (-2.05)			$4.1x10^4$ (2.20)															$4.0x10^4$ (2.21)	$3.5x10^4$ (1.86)	$4.6x10^4$ (2.39)	$5.3x10^4$ (2.50)	$3.9x10^4$ (2.10)	$3.2x10^4$ (1.90)	$4.1x10^4$ (2.29)			
4. δTRCS	SC	63-71	0.157	.741	2.74	$4.0x10^4$ (1.03)	$-2.3x10^3$ (-3.05)		$3.0x10^3$ (1.04)							2.32 (0.17)																		
5. δTRCS	W	63-71	0.617	.755	23.8	$8.9x10^3$ (2.12)	-315 (-6.01)		362 (1.22)								3.50 (8.53)																$4.6x10^4$ (6.08)	$3.0x10^3$ (3.59)
6. δTINS	NE	63-71	0.699	.639	26.9	$2.9x10^4$ (5.54)		-603 (4.53)			$9.3x10^3$ (1.25)				0.56 (4.02)			$3.0x10^5$ (8.36)	$2.0x10^5$ (4.86)															
7. δTINS	NC	63-71	0.594	.679	11.5	$2.4x10^4$ (2.72)		-958 (-2.56)			$3.1x10^4$ (1.89)			35.9 (13.2)						$2.3x10^5$ (1.89)	$-1.4x10^5$ (-3.61)	$1.1x10^5$ (5.03)	$1.0x10^5$ (3.10)	$1.4x10^5$ (4.14)										
8. δTINS	SE	63-71	0.779	.775	18.0			-262 (-5.71)			$1.1x10^5$ (4.69)			9.21 (1.21)											$7.5x10^5$ (6.06)	$7.6x10^5$ (5.95)	$8.1x10^5$ (6.37)	$8.5x10^5$ (5.57)	$6.2x10^5$ (4.91)	$5.9x10^5$ (5.48)	$7.7x10^5$ (5.90)			
9. δTINS	SC	63-71	0.555	.608	11.6	$1.1x10^5$ (2.21)		$-6.1x10^3$ (-2.98)					$1.2x10^5$ (2.11)	181 (6.59)																		$5.0x10^5$ (2.96)		
10. δTINS	W	63-71	0.426	.730	13.9	$8.3x10^3$ (2.95)		-390 (-4.32)				$4.5x10^4$ (3.38)		12.6 (2.84)																			$1.1x10^5$ (7.49)	

were estimated using the generalized least squares procedure described in Section 4.1, except that a single value for the serial correlation coefficient ρ was used for all districts, since there was almost no variation in this parameter from state to state. The final wholesale demand equations used in the model are shown below, with t-statistics in parentheses, and estimated values for the serial correlation coefficient and error term standard deviations for each state.

Residential and Commercial Demand for Gas:

Northeast:

$$\underset{}{\delta TRCS} = \underset{(0.89)}{13485} - \underset{(-3.54)}{719.67PGW_{-1}} + \underset{(1.36)}{1343.1PFOIL_{-1}} + \underset{(8.77)}{42.85\delta NN} \qquad (47)$$

$R^2 = 0.610$ $\quad F = 31.8$ $\quad S.E. = 0.762$ $\quad$ LHS Mean = 1.86

$\hat{\rho} = 0.2536$

	$\hat{\sigma}_i$		
MD	2929.8	OH	33490.3
NE	8934.3	PA	31997.6
NJ	6212.1	VA	3307.9
NY	18111.2	WV	10328.3

North Central:

$$\delta TRCS = \underset{(1.94)}{27968} - \underset{(-3.25)}{1702.4PGW_{-1}} + \underset{(3.27)}{90442PALT_{-1}} + \underset{(6.57)}{60.30\delta NN} + \underset{(3.48)}{38998IL}$$

$$+ \underset{(2.69)}{8832.0IO} + \underset{(2.55)}{10505WI} \qquad (48)$$

$R^2 = 0.409$ $\quad F = 7.507$ $\quad S.E. = 0.690$ $\quad$ LHS Mean = 1.49

$\hat{\rho} = 0.0122$

$\hat{\sigma}_i$			
IL	38464.0	MO	15947.9
IN	5551.4	NB	8645.0
IO	12318.4	SD	6695.0
MI	28207.2	WI	8913.0
MN	17284.5		

Southeast:

$$\delta TRCS = \underset{(0.74)}{11642} - \underset{(-1.81)}{790.4PGW_{-1}} + \underset{(1.80)}{1918.6PFOIL} + \underset{(1.03)}{1.240\delta YY} - \underset{(-2.06)}{5469.7FL}$$

$$+ \underset{(3.21)}{7272.6GA} + \underset{(2.74)}{7961.8KY} - \underset{(-2.51)}{4077.9SC} \qquad (49)$$

$R^2 = 0.394$ F = 4.46 S.E. = 0.649 LHS Mean = 1.10

$\hat{\rho} = -0.1116$

$\hat{\sigma}_i$			
AL	8695.8	NC	6855.3
FL	7528.2	SC	3967.1
GA	7655.8	TN	8880.5
KY	9737.8		

South Central:

$$\delta TRCS = \underset{(1.23)}{42648} - \underset{(-3.48)}{2355.0PGW_{-1}} + \underset{(1.04)}{2912.0PFOIL_{-1}} \qquad (50)$$

$R^2 = 0.158$ F = 4.23 S.E. = 0.819 LHS Mean = 0.713

$\hat{\rho} = -0.1662$

$\hat{\sigma}_i$			
AR	12435.0	MS	5942.9
KS	15894.0	OK	58741.0
LA	23897.1	TX	39922.6

West:

$$\delta TRCS = \underset{(1.47)}{5804.0} - \underset{(-6.51)}{313.8PGW_{-1}} + \underset{(2.13)}{593.4PFOIL_{-1}} + \underset{(7.97)}{21.30\delta NN}$$

$$+ \underset{(6.17)}{45642\ CA} + \underset{(4.36)}{3077.0NV} \qquad (51)$$

$R^2 = 0.565$ F = 19.22 S.E. = 0.709 LHS Mean 2.03

$\hat{\rho} = -0.7374$

	$\hat{\sigma}_i$		
AZ	10367.9	NM	13050.3
CA	42064.9	OR	2664.9
CO	13393.7	UT	3188.8
ID	1460.7	WA	5378.1
NV	2017.6	WY	6574.7

Industrial Demand for Gas:

Northeast:

$$\delta TINS = \underset{(3.32)}{25092} - \underset{(-3.20)}{589.2PGW} + \underset{(1.37)}{25519PALT} + \underset{(1.85)}{6.534CAP_{-1}}$$

$$+ \underset{(6.16)}{35061\ OH} + \underset{(3.16)}{23378\ PA} \qquad (52)$$

$R^2 = 0.570$ F = 11.1 S.E. = 0.467 LHS Mean = 1.068

$\hat{\rho} = -0.0337$

	$\hat{\sigma}_i$		
MD	5475.8	OH	22493.6
NE	9246.5	PA	35184.0
NJ	17745.9	VA	13234.4
NY	31235.3	WV	8328.1

North Central:

$$\delta TINS = \underset{(0.629)}{11099} - \underset{(-1.42)}{937.0PGW} + \underset{(1.23)}{64174\,PALT} + \underset{(6.85)}{2.818VAM}$$

$$+ \underset{(0.77)}{11243\,IL} - \underset{(-1.10)}{5938.0IN} + \underset{(3.14)}{1183.0IO} + \underset{(1.69)}{86840MN} + \underset{(1.99)}{9456.0WI} \quad (53)$$

$R^2 = 0.760$ F = 17.8 S.E. = 0.461 LHS Mean = 1.01

$\hat{\rho} = 0.1335$

	$\hat{\sigma}_j$		
IL	60259.8	MO	29891.1
IN	12732.6	NB	13584.6
IO	14344.4	SD	2622.1
MI	28859.2	WI	6527.3
MN	22337.1		

Southeast:

$$\delta TINS = \underset{(4.53)}{65234} - \underset{(-4.70)}{2145.0PGW} + \underset{(5.45)}{97293\,PALT} + \underset{(2.51)}{14.37CAP_{-1}}$$

$$- \underset{(-9.28)}{16681NC} - \underset{(-5.96)}{17735SC} \quad (54)$$

$R^2 = 0.897$ F = 62.5 S.E. = 0.460 LHS Mean = 1.88

$\hat{\rho} = -0.0923$

	$\hat{\sigma}_j$		
AR	31824.3	MS	37416.0
KS	20615.0	OK	86610.7
LA	103832.0	TX	218593.0

South Central:

$$\delta TINS = \underset{(1.52)}{73360} - \underset{(-2.85)}{5642.0PGW} + \underset{(2.16)}{191595\,POIL} + \underset{(5.51)}{158.7CAP_{-1}} + \underset{(3.08)}{56895\,LA} \qquad (55)$$

$R^2 = 0.649$ $\quad F = 14.3$ $\quad S.E. = 0.507$ $\quad$ LHS Mean $= 1.46$

$\hat{\rho} = -0.3645$

	$\hat{\sigma}_i$		
AR	31824.3	MS	37416.7
KS	20615.0	OK	86610.0
LA	103832.0	TX	218593.0

West:

$$\delta TINS = \underset{(4.00)}{9361.0} - \underset{(-4.22)}{465.4PGW} + \underset{(3.76)}{51805\,PCOAL} + \underset{(3.21)}{16.99CAP_{-1}} + \underset{(8.08)}{108575\,CA} \qquad (56)$$

$R^2 = 0.513$ $\quad F = 14.5$ $\quad S.E. = 0.459$ $\quad$ LHS Mean $= 1.03$

$\hat{\rho} = -0.7624$

	$\hat{\sigma}_i$		
AZ	27791.8	NM	19329.0
CA	110948.0	OR	9381.8
CO	22064.2	UT	16370.0
ID	3096.6	WA	32284.0
NV	5956.9	WY	16162.4

There is still another demand category which must be accounted for, and that is lease and plant fuel demand. This consists of demand for gas as an energy source for extracting and pressurizing gas at the field site. Since there is usually no alternative energy source as easily accessible at the site as the gas itself, the demand for plant gas is largely a function of the total quantity of gas produced. We estimated this demand equation by pooling data over the years 1968 to 1972 for all gas producing states, and using a dummy variable for the state of Texas to account for the fact that that state has a larger fraction of older fields, which probably require more extraction fuel in their operations. The resulting equation is shown below.

Demand for Gas as Field Extraction Fuel:

$$FS = \underset{(1.99)}{1525.0} + \underset{(15.14)}{0.0434QG} + \underset{(8.18)}{0.04993TX \cdot QG} \qquad (57)$$

$R^2 = 0.847$ $F = 135.9$ $S.E. = 0.538$ LHS Mean = 1.40

$\hat{\rho} = 0.8390$

	$\hat{\sigma}_i$		
AR	3869.2	OH	1594.7
CA	17666.4	OK	16484.2
CO	857.4	PA	543.4
KS	5787.2	TX	30703.1
LA	27128.5	UT	1909.4
MS	4085.7	WY	1932.7
NM	3267.4		

4.8. Estimated Equations for Wholesale Oil Demand

Oil demand is modeled in the residential/commercial and industrial sectors where it can be used as a substitute for natural gas. Within the residential/commercial market, No. 2 distillate home heating oil is the major competitor with natural gas, while in the industrial market, No. 6 residual fuel oil is the major oil product in use. In formulating and estimating the oil demand equations, care was taken to make them compatible with the equations for gas demand, so that structural equations tested were of the form:

$$\delta QO_t = f(PO_{t-1}, PG_{t-1}, \delta YY, \delta NN, \ldots) \qquad (58)$$

with $$\delta QO_t = \Delta QO_t + rQO_{t-1} \qquad (59)$$

Here, new demand for oil is modeled as a function of own price, PO, in the previous period, the price of natural gas, PG, or some other substitute, lagged one period, and the other explanatory variable (income, etc.) which explain growth in market size. The parameter r is the depreciation rate discussed in the last section.

The lags on prices are assigned *a priori* significance under the assumption that changes in the wholesale prices of oil and gas do not immediately affect the quantity of oil and gas demanded. The growth term can be one of several variables depending on the market being modeled, although income has been found to be the best general variable for market size. Other variables for growth are also used, such as value added in manufacturing, VAM, for industrial equations.

Equations of the form shown in (58) were tested over the time period 1964 to 1970 using data for forty states or groups of states in the Continental U.S.[30] The aggregation is the same as that used for natural gas demand, except that the South East, South Central and West regions are combined to form one "South" region (because only a small proportion of total fuel oil consumption occurs in these three regions). The consuming region breakdowns are shown in Table 4.6. (For a complete list of variable definitions, as well as data sources, see Section 4.2.)

Table 4.6

Regional Breakdown for Oil Demand Equations

1.	North East	Maryland + Delaware, New England, New Jersey, New York, Ohio, Pennsylvania, West Virginia, Virginia
2.	North Central	Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Nebraska, South Dakota, Wisconsin
3.	"South"	Kentucky, Alabama, Florida, Georgia, North Carolina, South Carolina, Tennessee, Arkansas, Kansas, Louisiana Mississippi, Oklahoma, Texas, Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Before the actual demand equations can be estimated it is necessary to select a value for the depreciation rate parameter r, as in the case of wholesale gas demand. In this instance the parameter r was estimated from $QO_t = (1-r)QO_{t-1} + \alpha AO_t$

[30] For example, the six New England states are combined into one district.

where QO_t is quantity of oil consumed in period t, and AO_t is the total stock of oil-burning equipment in place in period t. Pooling all 40 consumption districts together, the regression resulted in $\hat{r} = 0.1039$ (with t = 2.96 and R^2 = .996), so that a value of 0.1 for r is used in all equations.

Final equations for residential/commercial demand in each of the three regions are shown below, with t-statistics in parentheses. The estimated serial correlation coefficients (ρ_j) and error term standard deviations (σ_j) that were used in the generalized least squares estimations are also snown.

Northeast

$$\underset{}{\delta QO.2} = \underset{(-0.6843)}{-5829.8} + \underset{(1.90)}{237.2}PGW_{-1} - \underset{(-1.13)}{364.3}PFOIL_{-1} + \underset{(8.64)}{0.5372}\delta YY$$

$$\underset{(-0.83)}{-375.3}TDUM(1970) + \underset{(2.06)}{3969.9}NEW + \underset{(8.52)}{2497.1}NJ$$

R^2 = 0.88 F = 48.4 S.E. = 0.52 LHS Mean = 1.91

State	$\hat{\rho}_j$	$\hat{\sigma}_j$
MD	0.1798	1666.7
NE	-0.7295	5660.2
NJ	-0.3180	1352.6
NY	0.0780	5784.1
OH	-0.2131	1445.3
PA	-0.5425	2549.4
VA	-0.0968	1689.8
WV	-0.5049	1394.6

North Central

$$\delta QO.2 = \underset{(-2.00)}{-1695.0} + \underset{(4.58)}{92.52}PGW_{-1} - \underset{(-1.78)}{148.2}PFOIL_{-1} + \underset{(10.06)}{0.4706}\delta YY \qquad (61)$$

R^2 = 0.34 F = 8.6 S.E. = 0.67 LHS Mean = 1.17

State	$\hat{\rho}_j$	$\hat{\sigma}_j$
IL	-0.1743	1960.3
IN	0.2477	891.85
IO	0.1627	1073.6
MI	0.1388	872.01
MN	0.1566	1068.8
MO	0.0234	1055.7
NB	-0.3143	363.87
SD	-0.1472	190.26
WI	-0.0706	1116.2

South East and South Central and West ("South")

$$\underset{}{\delta Q0.2} = \underset{(-0.89)}{-152.8} + \underset{(5.11)}{15.18}PGW_{-1} - \underset{(-0.60)}{11.27}PFOIL_{-1} - \underset{(-4.09)}{221.1}AZ + \underset{(1.22)}{356.6}SC - \underset{(-2.97)}{177.3}NM \qquad (62)$$

$R^2 = 0.18$ $\quad$ F = 5.8 $\quad$ S.E. = 0.71 $\quad$ LHS Mean = 0.60

State	$\hat{\rho}_j$	$\hat{\sigma}_j$
AL	0.9035	113.87
AZ	-0.6197	256.29
AR	0.4483	131.03
CA	0.1560	301.58
CO	-0.1423	105.88
FL	-0.2998	1032.9
GA	-0.1404	294.63
ID	-0.0545	1796.4
KS	0.5330	192.27
KY	-0.3036	232.93
LA	0.5554	223.65
MS	-0.1640	300.73
NV	0.5811	172.09
NM	0.1834	158.02
NC	-0.3828	1295.9
OK	-0.5570	226.74
OR	-0.2679	296.74
SC	0.1529	850.80
TN	0.4002	292.13
TX	0.2946	604.85
UT	0.6261	177.38
WA	-0.6583	885.87
WY	-0.5867	196.10

The wholesale gas and oil prices appear with the correct signs in all three equations, although the oil price is not significant in the South equation. The South equation itself is barely significant (with an F-statistic of 5.8) and this is a reflection of the very small amount of oil that is consumed in that region. The growth variable that has the strongest explanatory power and that was used in the final equations is personal income. Note that this variable appears in its "incremental" form, i.e., $\delta YY = \Delta YY + rYY_{t-1}$, since it is assumed that the level of total demand depends on total income, so that "new" demand will depend on "new" income. This variable did not, however, appear significantly in the South equation, nor did any other growth variable, so that the only explanatory variable (other than state dummy variables) that appears in that equation is the wholesale price of natural gas.

A time dummy (TDUM) is used in the Northeast equation, and this is intended to account for changes in demand resulting from the stricter air pollution standards that went into effect around 1970 in Northeastern states. District (state) dummy variables are used in the Northeast and South equations to account at least in part for heterogeneities between some states.

Alternative regressions are given in Table 4.7 to indicate the results of using different state dummy variables (dummy variables included are shown together with the signs of the estimated coefficients). Often dummy variables are significant, but they eliminate any price and income effects. The objective was to find a combination of dummy variables that would improve the significance of the overall equation without cancelling out the significance of the price or income variables. Since this was not achieved with the equations in the table, they were abandoned in favor of those shown in the text above.

Table 4.7
ALTERNATIVE REGRESSION RESULTS FOR
RESIDENTIAL-COMMERCIAL OIL DEMAND (GLS RESULTS)

REGION	S.E.	MEAN DEP.VAR.	R^2	CONSTANT	PGW_{-1}	$POIL_{-1}$	δYY	δNN	TDUM70	STATE DUMMIES
Northeast	.9812	1.8874	.569	-8138.05 (-1.26)	395.37 (4.59)	-656.49 (-1.60)	.32 (1.56)			WV-
Northeast	.9909	1.8896	.558	-5780.14 (-.89)	384.94 (4.43)	-909.13 (-2.37)	.50 (4.21)			VA-
Northeast	1.0347	1.9572	.548	-6322.89 (-.95)	391.40 (4.34)	-883.70 (-2.17)	.49 (3.63)			NY+ PA-
Northeast	1.0246	1.9293	.557	-5411.54 (-.82)	399.62 (4.40)	-996.99 (-2.45)	.48 (3.78)			DM- NY+ PA-
Northeast	.9592	1.8166	.576	-4384.34 (-.68)	392.26 (4.44)	-1077.14 (-2.75)	.55 (4.95)			DM- PA-
Northeast	.8249	1.8706	.678	10121.20 (1.15)	-38.50 (-.25)	-798.39 (-2.50)	.84 (9.32)			DM- NEW+ PA-
Northeast	.5094	1.8457	.856	-17837.0 (-4.65)	500.14 (10.82)	-249.86 (-1.11)		.43 (6.57)	-595.29 (-1.66)	NJ+
Northeast	.9002	1.8223	.522	-5638.48 (-.86)	395.99 (4.85)	-902.76 (-2.37)		.50 (4.43)	-988.21 (-1.57)	
Northeast	.5194	1.9246	.8837	-10390.4 (-1.45)	291.51 (2.54)	-187.83 (-.72)		.54 (8.62)		NEW+ NJ+
Northeast	.5221	1.9196	.887	-13134.0 (-1.77)	344.47 (2.85)	-139.27 (-.52)		.52 (8.08)		DM- NEW+ NJ+
Northeast	.9505	1.8433	.607	-6015.96 (-.92)	395.26 (4.58)	-765.56 (-1.77)		.15 (.60)		WV- PA- VA-
Northeast	.9683	1.8466	.584	-6845.84 (-1.03)	393.56 (4.50)	-774.55 (-1.76)		.35 (1.63)		WV- PA-
Northeast	.9901	1.9770	.604	-11317.0 (-1.67)	389.98 (4.51)	-297.29 (-.65)		.25 (1.03)		WV- NY+

Table 4.7 Continued

REGION	S.E.	MEAN DEP.VAR.	R^2	CONSTANT	PGW_{-1}	$POIL_{-1}$	δYY	δNN	STATE DUMMIES
North Central	.4558	.8656	.4308	-2725.45 (-2.81)	124.89 (5.31)	-133.02 (-1.79)	.37 (6.25)		MN+ SD-
North Central	.4564	.8477	.333	-1021.39 (-1.43)	86.28 (4.98)	-198.07 (-2.76)		2.99 (9.56)	MN+
North Central	.445	.843	.377	-659.05 (-.95)	94.15 (5.60)	-262.02 (-3.28)		2.84 (8.40)	MN+ IN+
North Central	.6300	1.2550	.528	-3397.01 (-3.91)	172.48 (8.28)	-200.60 (-2.32)			IL+ IN+ MI+ MN+ MO+ SD-
South	.7369	.5778	.089	42.18 (.26)	10.49 (3.82	-19.35 (-1.06)			AZ- NM-
South	.7097	6032	.192	-190.29 (-1.10)	16.18 (5.41)	-10.01 (-.54)			AZ- AL+ NM-
South	.5027	.4317	.214	-172.75 (-1.01)	15.83 (5.11)	-5.11 (-.24)	-19.86 (-.64)		AZ- AL+ NM-
South	.6924	.6144	.228	-570.67 (-3.81)	9.78 (3.30)	-39.21			NC+ NV- WA+
South	.5207	.4285	.137	-21.39 (-.09)	15.35 (3.54)	-25.73 (-.81)		.01 (.10)	AZ- AL+ NM- UT+ WY+

Final equations for industrial oil demand in each region are shown below, again with estimated serial correlation coefficients and error term standard deviations:

Northeast

$$\underset{}{\delta RSID} = \underset{(-2.70)}{-23405} + \underset{(4.45)}{781.8PGW_{-1}} - \underset{(-3.03)}{10498POIL_{-1}} + \underset{(1.47)}{0.4002\delta YY} \qquad (63)$$

$R^2 = 0.45$ F = 12.0 S.E. = 0.90 LHS Mean = 1.11

State	$\hat{\rho}_j$	$\hat{\sigma}_j$
MD	0.3489	6195.6
NE	-0.0605	8390.3
NJ	0.2105	10875.
NY	-0.2765	9740.5
OH	0.1000	2921.5
PA	-0.0292	7121.0
VA	0.9116	5065.8
WV	-0.3579	1092.9

North Central

$$\delta RSID = \underset{(-2.06)}{-634.9} - \underset{(-1.48)}{502.2POIL_{-1}} + \underset{(6.97)}{0.6588\delta YY} + \underset{(1.22)}{142.1IO} + \underset{(2.66)}{512.3NB} + \underset{(4.71)}{891.8SD} + \underset{(0.72)}{336.5IN} \qquad (64)$$

$R^2 = 0.51$ F = 8.1 S.E. = 0.65 LHS Mean = 0.46

State	$\hat{\rho}_j$	$\hat{\sigma}_j$
IL	-0.2055	2245.9
IN	-0.0684	1837.5
IO	-0.5886	144.46
MI	0.5936	2777.4
MN	-0.1494	998.83
MO	-0.6152	918.44
NB	-0.0772	446.27
SD	0.4343	110.6
WI	-0.4569	644.11

Southeast and South Central and West ("South")

$$\delta RSID = \underset{(-1.21)}{-168.5} + \underset{(2.78)}{11.49} PGW_{-1} - \underset{(-3.58)}{413.2} POIL_{-1} + \underset{(6.82)}{0.6722}\delta VAM + \underset{(1.41)}{8477.0} FL \qquad (65)$$

$$+ \underset{(2.96)}{4932.0} CA + \underset{(2.18)}{321.0} WY + \underset{(3.25)}{1352.0} LA$$

$R^2 = 0.19$ F = 4.2 S.E. = 0.57 LHS Mean = 0.47

State	$\hat{\rho}_j$	$\hat{\sigma}_j$
AL	-0.4294	1540.6
AZ	-0.1511	389.62
AR	-0.9777	786.57
CA	-0.4262	10044.
CO	-0.4637	796.83
FL	0.6158	9995.2
GA	-0.3867	1699.0
ID	-0.0363	304.50
KS	-0.0426	522.49
KY	-0.0394	373.53
LA	-0.5730	2803.3
MS	0.5521	521.35
NV	0.3432	156.2
NM	-0.1082	940.64
NC	-0.1398	1131.9
OK	-0.5053	718.60
OR	-0.4451	1200.8
SC	0.1818	1848.0
TN	-0.5145	850.35
TX	-0.1831	2897.8
UT	-0.8124	1135.1
WA	-0.7868	1334.9
WY	-0.5411	1022.5

Income is again used as the growth variable in the Northeast and North Central regions, while value added in manufacturing is used in the South region. Regressions were run using alternative growth variables, but they were not as significant. Note that both the gas and oil prices appear significantly in the Northeast and South, but the price of gas was not significant and was thus omitted in the North Central equation. State dummy variables are included, this time in both the North Central and South equations. Again, the South equation is barely significant.

Alternative regressions for industrial demand are shown in Table 4.8. These regressions differ in the choice of growth variables (population, income, and value added), choice of time lags, and the use of state dummy variables. As before, state dummy variables were chosen for the final forms so as to improve the overall fit of the equations without decreasing the significance of price and growth variables. Those equations in the text would seem to be preferred for a policy model designed to analyze price controls, so that they are included in the final version of the simulation model.[31]

---

[31]It is important to point out that although three regions--the Southeast, South Central, and West--were merged into one in our oil demand equations, it is still possible to determine oil demand (under different price policies) for each of the regions over which gas demand equations are estimated. Values for price, income, etc., for each particular state are simply inserted into the equations when the model is simulated. The merging of three regions is simply a pooling process that is used because consumption in those regions is small and erratic, so that it is impossible to estimate individual equations (that are statistically significant) for each region. This does not limit our ability to analyze changes in demand on a regional basis.

Table 4.8
ALTERNATIVE REGRESSION RESULTS
FOR INDUSTRIAL OIL DEMAND

REGION:	S.E.	MEAN DEP. VAR.	R^2	CONSTANT	PGW_{-1}	$POIL_{-1}$	δYY	δVAM_{-1}	δVAM	VAM	STATE DUMMIES
Northeast	.5008	1.0036	.800	-44695.4 (-5.61)	825.43 (6.22)	-9,719.12 (-2.53)	5378.53 (4.18)				NY+ NJ+
Northeast	.4994	1.0302	.808	-44564.3 (-6.06)	778.28 (6.52)	-12,222.0 (-3.19)	6303.38 (5.05)				NY+
Northeast	.8036	1.0170	.667	-2409.0 (-.17)	616.13 (2.21)	-26,927.2 (-6.82)					
Northeast	.5130	.6868	.744	-6359.58 (-.45)	710.02 (2.43)	-25,533.90 (-5.78)		2.52 (.30)			OH-
Northeast	.4503	.9836	.883	-13819.5 (-2.55)	322.74 (2.37)	-1237.17 (-.52)		6.11 (5.68)			NY- OH- PA-
Northeast	.7974	.9753	.651	-4536.63 (-.32)	698.65 (2.53)	-27787.0 (-5.85)			-.48 (-.83)		
Northeast	.9241	1.0832	.564	-13502.3 (-1.05)	787.88 (3.14)	-21669.2 (-4.78)				-.03 (-.36)	

Table 4.8 . Continued

REGION:	S.E.	MEAN DEP.VAR.	R^2	CONSTANT	PGW_{-1}	$POIL_{-1}$	δYY_{-1}	δYY	TDUM70	δVAM_{-1}	δNN	STATE DUMMIES
North Central	.4239	.3534	.736	-6026.09 (-4.46)	96.66 (3.68)	1885.70 (1.75)	711.53 (5.55)					IL+ MO+ IO- NB- MI- SD- MN- WI-
North Central	.4257	.3512	.704	-5840.51 (-3.79)	88.54 (2.60)	2240.78 (2.00)	668.12 (5.05)					IL+ NB- IO- SD- MN- WI- MO+
North Central	.4447	.3412	.553	-1897.46 (-2.68)	-10.31 (-.56)	449.99 (.62)		663.51 (4.16)				IL+
North Central	.5238	.3569	.562	-3578.49 (-1.97)	-88.71 (-2.29)	122.59 (.08)		2114.70 (6.52)	263.55 (.89)			
North Central	.7251	.4269	.032	1048.75 (1.64)	-54.32 (-2.54)	1103.52 (1.65)				.38 (3.35)		
North Central	.9609	.6504	.557	-6096.93 (-4.44)		-1338.46 (-1.11)		2291.54 (7.33)				
North Central	.7415	.5931	.661			2441.21 (1.96)	644.70 (4.54)					IN- MO- IL- NB- IO- SD- MI- WI- MN-
North Central	.6795	.4583	.417	-130.32 (-.55)		-814.83 (-2.28)					.53 (7.16)	SD+ IN+
North Central	.8708	.4592	-.012	-39.27 (-.14)		-360.27 (-.87)					.25 (3.38)	IN+
North Central	.7293	.4594	.253	-244.47 (-.69)		-429.94 (-.79)					.47 (6.05)	WI-
North Central	.6857	.4606	.397	-236.49 (-1.12)		-600.01 (-1.92)					.51 (7.25)	SD+
North Central	.7594	.4575	.238	-273.44 (-1.02)		-422.84 (-1.07)					.45 (5.86)	NB+
North Central	.7778	.4607	.189	-118.02 (-.49)		-569.16 (-1.58)					.40 (5.28)	MN+
North Central	.7225	.4610	.305	30.85 (.14)		-471.24 (-1.43)					.38 (5.32)	IO-

Table 4.8 Continued

REGION:	S.E.	MEAN DEP. VAR.	R^2	CONSTANT	PGW_{-1}	$POIL_{-1}$	δVAM	PGW	POIL	δVAM_{-1}	STATE DUMMIES
South	.9321	.6408	.115	-258.43 (-2.08)			.89 (7.76)	9.75 (2.78)	-291.62 (-2.46)		
South	.7639	.5384	-.048	-21.01 (-.20)	4.27 (1.40)	-233.80 (-2.29)				.58 (6.10)	
South	.6454	.4899	.066	-70.99 (-.55)	7.58 (2.10)	-337.76 (-3.28)	.73 (6.83)				FL+
South	.6056	.4849	.053	-32.26 (-.24)	6.91 (1.78)	-348.50 (-3.31)	.56 (6.14)				FL+ CA+ WY+
South	1.0197	.5091	-.026	-127.94 (-.50)	13.02 (1.51)	-32.90 (-.14)					

4.9. Interregional Flows of Gas in the Econometric Model

As explained in Section 3.7, interstate gas production is allocated from 8 producing regions to 40 demand regions through a set of static input-output coefficients f_{ij} and g_{ij} which determine, respectively, the fraction of state i's gas which comes from supply region j, and the fraction of district j's production which is supplied to state i. The only further allocation is between intra- and interstate markets; this is made according to a price-dependent distribution equation. In this section we describe the method used to calculate the input-output coefficients, as well as the estimation of the interstate-intrastate distribution equations. The actual breakdown of producing and consuming regions used in the model is shown in Table 4.9.

In estimating the I-O coefficients for gas from the different supply regions to each demand region, there are three determining factors: (1) how much gas each pipeline company obtains from each production region, (2) how much is delivered to each state, and (3) how much each state obtains from each pipeline company. These are accounted for as follows. First, a schematic diagram is drawn for each pipeline company (see the example in Figure 4.1 in which the sale of gas in each state is represented by a square and each pipeline segment by a horizontal directed arrow. A purchase by the pipeline in a given state is represented by an incoming vertical arc which is labeled by type (i.e. field purchases and pipeline's own production (Δ), or purchases from another pipeline (0)). Sales are similarly represented by outgoing vertical arcs.[32]

---

[32] These diagrams are based on the FPC map, Principal Natural Gas Pipelines in the U.S. as well as on pipeline sales data extracted from FPC Form 11 reports.

TABLE 4.9

PRODUCING AND CONSUMING REGION BREAKDOWNS

Aggregated Producing Regions

1.	Mid-Continent	Texas 10
		Oklahoma
		Kansas
		Arkansas
2.	Permian	New Maxico San Juan
		New Mexico Permian
		Texas 7C
		Texas 8
		Texas 8A
3.	Mid-Texas	Texas 1
		Texas 9
		Texas 5
		Texas 7
4.	Gulf Coast	Texas 2
		Texas 3
		Texas 4
		Louisiana South (onshore)
		Louisiana South (offshore)
		Louisiana North
		Mississippi
		Texas 6
5.	Rocky Mountain	Colorado
		Utah
		Wyoming
		Montana
		Nebraska
		North Dakota
6.	California	California Intrastate
7.	Appalachia	West Virginia
		Kentucky
		Pennsylvania
		Michigan
		New York
		Ohio
8.	Canada	Canadian Imports

Aggregated Consuming Regions (for Table 4.9)

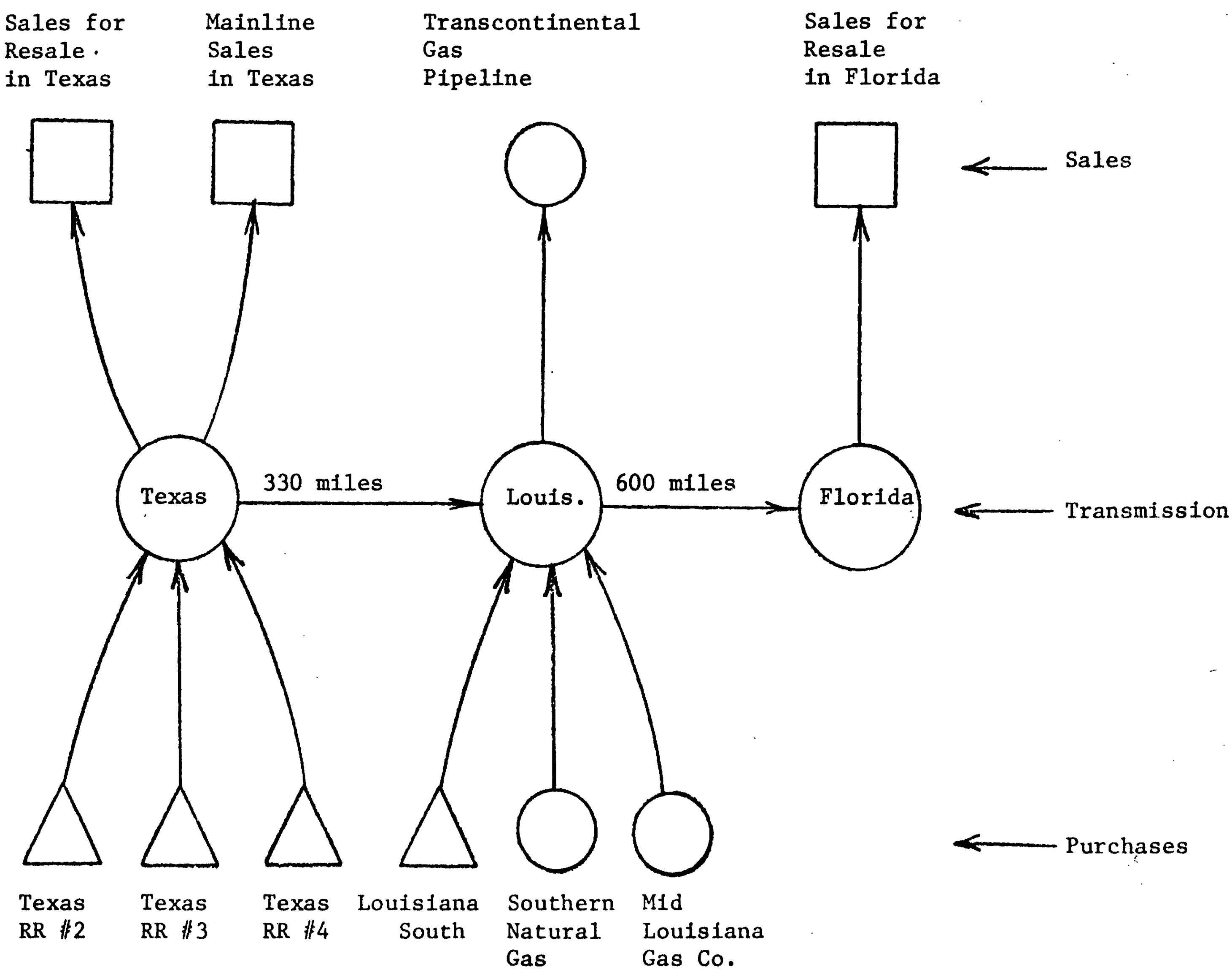
1.	NE	Maryland-Delaware, New England, New Jersey, New York, Ohio Pennsylvania, West Virginia, Virginia
2.	NC	Illinois, Indiana, Iowa, Michigan Minnesota, Missouri, Nebraska, South Dakota, Wisconsin
3.	SE	Alabama, Florida, Georgia, North Carolina, South Carolina, Tennessee, Kentucky
4.	SC	Arkansas, Kansas, Louisiana, Mississippi, Oklahoma, Texas
5.	W	Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Consumers

1.	AL	Alabama
2.	AZ	Arizona
3.	AR	Arkansas
4.	CA	California
5.	CO	Colorado
6.	MD	Maryland Delaware District of Columbia
7.	FL	Florida
8.	GA	Georgia
9.	ID	Idaho
10.	IL	Illinois
11.	IN	Indiana
12.	IO	Iowa
13.	KS	Kansas
14.	KY	Kentucky
15.	LA	Louisiana
16.	MI	Michigan
17.	MN	Minnesota
18.	MS	Mississippi
19.	MO	Missouri
20.	NB	Nebraska
21.	NV	Nevada
22.	NE	New England
23.	NJ	New Jersey
24.	NM	New Mexico
25.	NY	New York
26.	NC	North Carolina
27.	OH	Ohio
28.	OK	Oklahoma
29.	OR	Oregon
30.	PA	Pennsylvania
31.	SC	South Carolina
32.	SD	South Dakota
33.	TN	Tennessee
34.	TX	Texas
35.	UT	Utah
36.	VA	Virginia
37.	WA	Washington
38.	WV	West Virginia
39.	WI	Wisconsin
40.	WY	Wyoming

Figure 4.1

Florida Gas Transmission Pipeline System Model



From these diagrams it is possible to determine how different production districts feed gas into different states along each pipeline. Figures on sales and purchases from 1966 to 1971 are used to estimate on a state by state basis the approximate fraction of sales which have come from each of the eight supply regions along each pipeline. For the majority of pipeline companies, this estimation is trivial as they receive gas from only one region, and hence the fractions are 1.00 or 0.00. Some companies, however, receive gas from several regions and other pipelines as well, and in these cases estimates (assumed to be time-invariant) are made from simple calculations based on the more recent FPC Form II data.[33] The next step involves multiplying every sale made by an interstate natural gas pipeline company (other than sales to other interstate pipeline companies) by these fractions and then summing the products over the various pipelines:

$$S_{ij} = \sum_k a_{ijk} t_{ik} \qquad (66)$$

S_{ij} = total sales in state i from production district j

t_{ik} = sales in state i by pipeline k

a_{ijk} = fraction of pipeline k's sales in state i coming from production district j.

This quantity (S_{ij}) is then divided by the total quantity of gas delivered to state i and by the total quantity of gas supplied to the states by supply district j, to determine, respectively f_{ij} and g_{ij}:

$$f_{ij} = \frac{S_{ij}}{\sum_j S_{ij}} \qquad (67)$$

---

[33] For example, Consolidated Gas Supply gets approximately 11% of its gas from Appalachia and 89% from Gulf Coast, while Michigan-Wisconsin Pipeline Company delivers Midcontinental gas to Kansas, Missouri, Iowa, Illinois, and Wisconsin but Gulf Coast gas to Louisiana, Tennessee, Indiana, Ohio and Michigan.

$$g_{ij} = \frac{S_{ij}}{\sum_i S_{ij}}$$

where f_{ij} = fraction of state i's gas obtained from supply region j,

and g_{ij} = fraction of gas supplied by district j which goes to state i.

The coefficients were calculated for each year over the period 1966 through 1971, and are shown for three representative years in Tables 4.10a b, and c.[34] Note that the coefficients do change somewhat over time, since the quantities sold by each company to each state varied over this period. The variations, however, are usually less than 10%, so that we may treat the coefficients as constant. We use the coefficients calculated for 1971 in the final simulation model.[35]

This procedure has been altered somewhat to account for those sales of gas which are not regulated by the FPC and which therefore are not included in the Form II reports—that is, intrastate sale and lease and plant fuel sales. We account for these sales by using the identity

$$P_j = S_j^{inter} + S_j^{intra} + S_j^{LPF} + L_j \qquad (69)$$

where

P_j = total production in district j

S_j^{inter} = total sales by producers of gas in district j to interstate pipeline companies

[34] The tables present a reduced verions of the complete input-output matrices (which specify demand on a state-by-state basis). In these tables demand is aggregated into 5 large demand regions.

[35] Time-varying coefficients were also estimated which were functions of the prices offered by the producing regions to the consuming regions. Regressions were run in which the dependent variable was the fraction f_{ij}, and the independent variables were the prices offered by each of the regions that supply the given consuming region. (The regression coefficients were constrained so that the fractions would always add to one.) The estimation results were largely insignificant because there was too little variance in the dependent variables--largely due to the rigidity of the pipeline structure and the supply shortages brought on by regulation. Consequently the constant input-output coefficients were used.

Table 4.10a U. S. Natural Gas Flows for 1966

Quantity (10^9 cubic feet) f_{ij} g_{ij}	Midcontinent	Permian	Mid Texas	Gulf	Rocky Mtn.	Canada	California	Appalchian	Total
NE	117 .036 .035	0 .000 .000	0 .000 .000	2686 .839 .283	0 .000 .000	0 .000 .000	0 .000 .000	400 .125 1.000	3203 .183
NC	1289 .424 .388	353 .116 .157	40 .013 .092	1278 .420 .135	70 .023 .120	9 .003 .025	0 .000 .000	0 .000 .000	3039 .173
SE	0 .000 .000	0 .000 .000	0 .000 .000	1012 1.000 .107	0 .000 .000	0 .000 .000	0 .000 .000	0 .000 .000	1012 .058
SC	1758 .246 .529	477 .067 .211	390 .055 .908	4523 .633 .476	0 .000 .000	0 .000 .000	0 .000 .000	0 .000 .000	7148 .408
W	161 .053 .048	1426 .466 .632	0 .000 .000	0 .000 .000	450 .147 .767	340 .111 .975	686 .224 1.000	0 .000 .000	3063 .175
Total	3325 .190	2257 .129	430 .025	9498 .542	586 .033	349 .020	686 .039	400 .023	17530

Note: Numbers might not always add to totals due to rounding.

Table 4.10b. U.S. Natural Gas Flows for 1969

Quantity (10^9 cubic feet) f_{ij} g_{ij}	Midcontinent	Permian	Mid Texas	Gulf	Rocky Mtn.	Canada	California	Appalachian	Total
NE	133 .036 .035	0 .000 .000	0 .000 .000	3230 .873 .287	0 .000 .000	0 .000 .000	0 .000 .000	336 .091 1.000	3699 .184
NC	1576 .411 .412	433 .113 .173	51 .013 .119	1673 .436 .149	76 .020 .130	26 .007 .052	0 .000 .000	0 .000 .000	3835 .191
SE	0 .000 .000	0 .000 .000	0 .000 .000	1308 1.000 .116	0 .000 .000	0 .000 .000	0 .000 .000	0 .000 .000	1308 .065
SC	1926 .245 .503	513 .065 .204	374 .048 .881	5035 .642 .448	0 .000 .000	0 .000 .000	0 .000 .000	0 .000 .000	7848 .390
W	195 .058 .051	1563 .467 .623	0 .000 .000	0 .000 .000	447 .134 .762	482 .144 .948	659 .197 1.000	0 .000 .000	3346 .166
Total	3830 .191	2509 .125	424 .021	11246 .560	587 .029	509 .025	659 .033	336 .017	20100

Note: Numbers might not always add to totals due to rounding.

Table 4.10c U.S. Natural Gas Flows for 1971

Quantity (10^9 cubic feet) f_{ij} g_{ij}	Midcontinent	Permian	Mid Texas	Gulf	Rocky Mtn.	Canada	California	Appalachian	Total
NE	151 .039 .040	0 .000 .000	0 .000 .000	3391 .867 .292	0 .000 .000	0 .000 .000	0 .000 .000	369 .094 1.000	3911 .186
NC	1691 .404 .447	457 .109 .150	56 .013 .143	1856 .443 .160	80 .019 .133	45 .011 .072	0 .000 .000	0 .000 .000	4185 .199
SE	0 .000 .000	0 .000 .000	0 .000 .000	1382 1.000 .119	0 .000 .000	0 .000 .000	0 .000 .000	0 .000 .000	1382 .066
SC	1725 .217 .456	900 .113 .294	338 .042 .857	4990 .628 .429	0 .000 .000	0 .000 .000	0 .000 .000	0 .000 .000	7952 .378
W	218 .062 .057	1694 .480 .555	0 .000 .000	0 .000 .000	467 .132 .774	580 .164 .928	572 .162 1.000	0 .000 .000	3529 .168
Total	3785 .180	3050 .145	394 .019	11619 .553	603 .029	625 .030	572 .027	369 .018	21016

Note: Numbers might not always add to totals due to rounding.

S_j^{intra} = total intrastate sales in district j

S_j^{LPF} = lease and plant fuel sales in district j

L_j = losses, including losses in extraction of natural gas liquids

Since the production figures of the API and AGA[36] exclude extraction losses and since intrastate and lease and plant fuel losses due to transportation are expected to be relatively small, we can write:

$$S_j^{intra} + S_j^{LPF} = P_j' - S_j^{inter} \tag{70}$$

where P_j' is the AGA estimate of production in district j. These sales (left-hand side of (70)) are then added to S_{ij} for those states which produce gas and equations (67) and (68) are used to calculate the f_{ij} and g_{ij}.

One remaining computational problem is that of allocating supplies of gas between inter- and intrastate markets. We argued in Chapter 3 that the fraction of gas allocated to intrastate sales (PCT) in gas-producing states should be a function of the ratio of the intra- and interstate prices, P_{in}/P_{out}. The simplest functional specification for this fraction would be:

$$PCT = c_0 + c_1(P_{in}/P_{out}) \tag{71}$$

This equation can be estimated on a region-by-region basis, or all the regions can be pooled and a single estimate of c_1 obtained. The coefficient c_1 should have a positive sign since we expect production supply to depend positively on price.

The PCT series was derived from the FPC Form II data. Intrastate sales were available on a state-by-state basis, making it straightforward to aggregate states served by a given producing region. The only computational problem was the state of Texas, since it obtained intrastate gas from four regions (Midcont., Permian, MidTexas, Gulf), while no

---

[36] Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the U.S. and Canada AGA, API, CPA.

state received intrastate gas from more than one region. Texas intrastate sales were therefore divided among the four regions in the same proportion as total sales in Texas (this is reasonable since less than 15% of gas consumption in Texas is interstate). Total intrastate sales could then be divided by total sales in that region to obtain the percentage estimate.

Interstate prices were obtained by averaging Table F data for each district, weighted by total production. Intrastate new contract prices were obtained from FPC Docket No. R-389A, which were averaged and weighted by total production to obtain regional new contract prices. These were then "rolled in" to obtain average intrastate wellhead prices by region.[37]

Equation (71) was estimated over the years 1966-71 using data from five supply regions. California was omitted from the estimation because all gas produced there is assumed to be intrastate; Canada was omitted because any gas produced there that enters the U.S. is by definition interstate; and Kentucky and West Virginia were omitted because almost all of their gas production has been interstate.

It was expected that the dependence of percentage allocation on the ratio of prices would vary among production regions, and some attempt was made to account for this heterogeneity when estimating equation (71). It was found that best estimates were obtained through the use of two separate regression equations, the first estimated over the Midcontinent, Permian, Mid-Texas, and Rocky Mountain production regions (but including regional intercept dummy variables), and the second estimated over only the Gulf region. The estimation results are shown below in equations (72) and (73) which apply, respectively, to the four pooled regions and to the Gulf region:

---

[37] The "roll-in" equation is given in footnote 18 in Section 4.4.

$$PCT = \underset{(-1.39)}{-0.463} - \underset{(-2.62)}{0.101}DPERM - \underset{(-4.10)}{0.252}DTEX + \underset{(11.61)}{0.499}DMTN + \underset{(2.50)}{0.841}(P_{in}/P_{out}) \qquad (72)$$

$R^2 = .962$ $\qquad\qquad$ $F(4/19) = 120.5$

$$PCT = \underset{(-0.49)}{-0.202} + \underset{(1.28)}{0.507}(P_{in}/P_{out}) \qquad (73)$$

$R^2 = .290$ $\qquad\qquad$ $F(1/4) = 1.63$

Equation (72) fits the data well, with the relative price term significant at the 95% level. Although equation (73) as a whole is not significant at the 90% level, the dependent variable has very little variance in the Gulf region, so that the equation will be adequate for simulation purposes.[38]

In the final form of the model the static input-output coefficients calculated for 1971 are used for all states. But in those five regions where intrastate sales are significant, the relative price equations (72) and (73) are applied to state sales first. In these states intrastate sales are subtracted from consumption figures in Table 4.9.6, and new f_{ij} and g_{ij} coefficients are calculated. In simulations of the model, the fraction (1-PCT) of gas which leaves each producing region is allocated via the g_{ij} coefficients to the different demand regions, and the remainder is sold as intrastate gas within that production region.

---

[38] The regression equations (72) and (73) provide no guarantee that PCT will remain in the interval (0,1), thus logical operators are included in the simulation program to prevent PCT from taking on values outside this interval.

4.10. Summary

The estimated equations that are used in the final form of the model are summarized on a block-by-block basis in Table 4.11 (with references to the regression results in the text). Each equation was chosen not only on the basis of statistical fit, but also on how well the equation tracked the actual data when simulated over an historical time period individually or as part of the block to which it belongs.[39]

The statistical fit of the individual equations varies from block to block, but on the whole is good, particularly considering the degree of structural and regional detail in the model. The reserves equations have the weakest fit and contain a good deal of unexplained variance, reflecting the stochastic elements of the discovery process that do not conform to economic laws. The production, offshore, markup, and demand equations all fit the data well, however. The reserves equations are also the most non-linear part of the model, so that errors in these equations, as they are squared and multiplied, may become magnified during simulation of the model. Since it is the level of reserves (and not reserve additions) that affects production in the model, errors in the reserves equations should not accumulate across other blocks of equations.

There are a total of only thirty-nine estimated behavioral equations, but a much larger number of equations must be solved simultaneously when the model is simulated. This is due to the regional structure of the model, and the fact that equations were estimated by pooling cross-section and time-series data. Thus although a single equation is estimated for the pipeline price markup, forty equations must be written to explain the wholesale price in

---

[39] Much of the model's explanatory power, however, lies in the dynamic interactions of variables both within and across blocks, so that an important test of the validity of the model is its ability to track historical data when simulated as a whole. This overall historical simulation is described in Chapter 5.

each of forty demand regions when the model is simulated. Similarly, the nine reserves equations become 180 equations that apply to 20 production districts, the six wholesale oil demand equations become 80 equations that determine (separately) residential/commercial and industrial oil demand in each of the forty demand regions, etc.

In addition to this "multiplication" of the behavioral equations, all of the accounting identities in the model are "multiplied" (e.g., equations defining cumulative wells drilled, total reserves, etc., must be written for <u>each</u> production district). Finally, the input-output matrix must be expressed as a set of simultaneous equations that determine gas flows from producing to consuming regions. As a result the model, in its simulation format, contains some 1250 equations (or "statements") that must be solved simultaneously.

Simulation results for the model are presented in the next chapter. We will first examine a simulation of the model over an historical time period, and this will test the ability of the model as a whole to reproduce the actual behavior of gas markets. Then we will present the forecast simulations that were used in the policy analyses of Chapters 1 and 2.

Table 4.11

Estimated Equations of the Model

Block	Variables Explained	Number of Equa.	Estimation Method	Equation Numbers in Text
Reserves	Exploratory Wells (WXT)	1	↑	(16)
	Size of Discovery, gas and oil (SZG,SZO)	2		(17), (18)
	Success Ratio, gas and oil (SRG,SRO)	2	GLS, with single ρ for all districts	(19), (20)
	Extensions, gas and oil (XG,XO)	2		(21), (22)
	Revisions, gas and oil (RG,RO)	2	↓	(27), (28)
Production (onshore)	Production out of reserves (QG), for each of 3 regions	3	GLS with TSLS	(29), (30), (31)
Offshore Model	Acreage, Reserves, Production (WWT,DG, XRG, FWT, QG, ACRD, ACPN).	7	Second-order serial correlation with TSLS.	(34), (37) (38), (39) (40), (41), (42)
Price Markup	Wholesale Gas Price(PGW)	1	GLS	(43)
Wholesale Gas Demand	Res./Comm. Demand (TRGS) and Indus. Demand(TINS) for each of 5 regions; Extraction fuel demand (FS)	11	↑ GLS with TSLS ↓	(47),(48),(49) (50),(51),(52) (53),(54),(55) (56),(57)
Wholesale Oil Demand	Res./Comm. Demand (QO2) and Indus. Demand(RSID) for each of 3 regions	6	GLS	(60),(61),(62), (63),(64),(65)
Interregional Flows	Input-Output Coefficients	--	see Section 4.9	Table 4.9c
	Intrastate Allocations (PCT) for each of 2 regions	2	GLS	(72),(73)

CHAPTER 5:

SIMULATIONS OF THE ECONOMETRIC MODEL

The model of the natural gas industry described in the last two chapters consists of a set of equations which have been specified and estimated independently from each other. Taken one at a time, these equations are of limited use for forecasting the behavior of the gas industry. As we said in the beginning of Chapter 3, in order to analyze the industry it is necessary that one take into account the simultaneous interaction of supply and demand on both field and wholesale levels, i.e., that one view the industry as a complete system. This is done by simulating the model as a whole, i.e., by solving as a simultaneous system the set of equations that comprise the model.[1]

In this chapter, simulation results will be presented that relate to both the past and future behavior of the natural gas industry. In Section 5.1, we examine a simulation performed over a period in the recent past, namely 1967 through 1972. This historical simulation serves an important purpose. By comparing the simulated with the actual historical values of the endogenous variables in the model, we can determine how well the model reproduces the behavior of the industry, and this provides one measure of model validation. If, for example, the simulation shows no upward or downward bias in production over time, it might be expected that the model's predictions for future excess would show no bias when compared to actual values five years hence. On the other hand, any bias in the historical simulation might be expected to be repeated in forecasting.

In the second set of simulations we use the model for forecasting and

---

[1]The word "simulation" simply refers to the solution of a set of simultaneous time-dependent equations.

policy analysis. In Section 5.2 simulations are presented for the model through the year 1980, under alternative regulatory policies and alternative assumptions about future economic conditions. These alternative forecast simulations have been discussed in Chapter 2 in the context of their policy implications. In this chapter, we examine them in more detail and determine how sensitive they are to assumptions made about exogenous economic variables. Finally, in Section 5.3, we illustrate the diverse uses of the model by forecasting the demands by region of a gas substitute contingent on Federal price policies for gas in the field.

5.1. Historical Simulations

An historical simulation is performed by using actual 1966-1972 values for the exogenous variables and actual 1966 values for the endogenous variables as "start up" values to solve the model for 1967-1972 values of the endogenous variables. The computed values are shown for the most important endogenous variables of the model in Tables 5.1 through 5.20. In addition to listing the simulated values, actual values, and errors for each variable, we indicate the mean and root-mean-square (RMS) simulation errors.

Additions to reserves and its components for both gas and oil are shown in Tables 5.1 and 5.5. Although total wells drilled is simulated with an RMS error of only 12 percent, these errors are combined with errors from the success ratio and size of discovery equations so that new discoveries of natural gas simulate with an RMS error that is about 40 percent of the mean actual value. New discoveries of oil have a percentage RMS error that is relatively smaller, as smaller errors are introduced in the oil success ratio. Combined with errors in extensions and revisions, additions to reserves for natural gas have an RMS error that is about 50 percent of the mean actual value, and additions to reserves of oil have an RMS error that is about 20 percent of the mean actual value.

Although these RMS errors are large in magnitude, particularly for natural gas, we can observe from the tables that most of the error occurs in one year, namely 1968, when the model fails to reproduce a large one-year decrease that occurred in new discoveries. (The very low level of new discoveries in that year is impossible to explain on economic grounds or on the basis of geological conditions). Much of the remaining error in additions to gas reserves comes from revisions which, as explained in Section 3.2, is an erratic series that is difficult to analyze in an econometric model. The model simulates positive (though small) gas revisions over the entire period, while actual gas revisions were negative from 1969 to 1972. The net result is that the model overpredicts additions to gas reserves. For these reasons the level of total gas reserves is overpredicted by about 10 percent by 1972.

Simulation values for production, the average wellhead price, and the average wholesale price are all shown in Table 5.7. Although the simulated values for total reserves are too high by about 6 percent in 1970 and 9 percent in 1971, the simulated values for production in 1971 and 1972 are almost exactly equal to the actual values. Although this is in part a result of emphasis in the production model on variables other than reserves, in part it is a result of too-high predictions of reserves-to-production ratios.

In all, it is not possible to say that policy analysis of the 1960's would have been much affected by upward bias in historical simulations of reserves, and downward bias in reserve-production ratios. Policy analysis is focused on gas production and demand, and the dependence of these on regulated prices. We thus place a greater emphasis on the ability of the model to reproduce past behavior of production, demand, and prices in evaluating its applicability to such policy analysis.

As can be seen in Table 5.7, gas production is simulated with an RMS error that is about 2 percent of the average actual value. Average wellhead and wholesale prices are simulated with RMS errors that are respectively 1 percent and 3 percent of their average values, so that the field price "roll-in" mechanism is being accurately represented, as is the price mark-up charged by pipeline companies.

Simulation results of the demand for gas are shown on a regional and sectoral basis in Tables 5.8 through 5.15. Simulated values for demand in all regions are close to the actual values, with average RMS errors that range from 1 percent to 6 percent. The larger errors occur in the South Central region, which is not surprising in view of the poor statistical fits of the demand equations that were estimated for that region.[2]

Finally, historical simulation results for wholesale oil demand are shown by region and by type (distillate oil for residential/commercial use and residual oil for industrial use) in Tables 5.16 through 5.20. Although simulations for oil demand are not as close to the actual values as in the case for natural gas demand, the RMS simulation errors are generally less than 10 percent of the mean actual values, so that we have enough confidence in this part of the model to include an analysis of wholesale oil markets in our forecasts under alternative policy assumptions.

In summary, the historical simulation shows a small upward bias in the prediction of reserve levels, but this is counterbalanced by an over-prediction of the reserve-production ratio, so that there is no net bias in predictions of natural gas supply. This would indicate that our policy analyses and estimates of future gas shortages are, if anything, somewhat conservative.

---

[2]Simulated values for both production demand and supply are much closer to the actual values than was the case in the earlier version of this model described in P.W. MacAvoy and R.S. Pindyck [57], and demand equations have essentially the same functional form that they did in that earlier model. We attribute at least part of the improvement in the model's simulation performance to the GLS technique that was used in its estimation.

TABLE 5.1: Historical Simulation of Gas and Oil Well Drilling Activity

Year	(1) Simulated Total Wells	(2) Actual Total Wells	(3) Wells Error (1) - (2)	(4) Simulated Successful Gas Wells	(5) Actual Successful Gas Wells	(6) Gas Wells Error (4) - (5)	(7) Simulated Successful Oil Wells	(8) Actual Successful Oil Wells	(9) Oil Wells Error (7) - (8)
1967	7964	6754	1211	361	316	45	813	858	-45
1968	7760	6621	1139	349	263	86	855	672	183
1969	6748	7113	-365	284	367	-83	588	883	-295
1970	5759	5590	169	236	369	-133	520	622	-102
1971	4665	4990	-325	194	318	-124	395	499	-104
1972	5415	5163	252	218	422	-204	422	533	-111

MEAN TOTAL WELLS ERROR = 347
RMS ERROR = 718
MEAN ACTUAL = 6038

MEAN SUCCESSFUL GAS WELLS ERROR = -69
RMS ERROR = 123
MEAN ACTUAL = 343

MEAN SUCCESSFUL OIL WELLS ERROR = -79
RMS ERROR = 161
MEAN ACTUAL = 678

TABLE 5.2 : Historical Simulation of Gas and Oil Discoveries

Year	(1) Simulated Gas Discoveries (trillions cu.ft)	(2) Actual Gas Discoveries (trillions cu.ft)	(3) Gas Discoveries Error (1) - (2)	(4) Simulated Oil Discoveries (billions of brls.)	(5) Actual Oil Discoveries (billions of brls)	(6) Oil Discoveries Error (4) - (5)
1967	5.5	5.2	0.3	0.34	0.28	0.06
1968	7.5	2.7	4.8	0.36	0.27	0.09
1969	6.1	3.7	2.4	0.19	0.24	-0.05
1970	4.8	5.6	-0.8	0.21	0.31	-0.10
1971	5.5	5.9	-0.4	0.17	0.14	-0.03
1972	6.9	4.7	2.2	0.18	0.27	-0.09

MEAN GAS DISCOVERIES ERROR = 1.4
RMS ERROR = 2.4
MEAN ACTUAL = 4.6

MEAN OIL DISCOVERIES ERROR = -0.01
RMS ERROR = 0.08
MEAN ACTUAL = 0.25

TABLE 5.3: **Historical Simulation of Gas and Oil Extensions**

Year	(1) Simulated Gas Extensions (trillions cu.ft)	(2) Actual Gas Extensions (trillions cu.ft)	(3) Gas Extensions Error (1) - (2)	(4) Simulated Oil Extensions (trillions cu.ft)	(5) Actual Oil Extensions (billions of bbls)	(6) Oil Extensions Error (4) - (5)
1967	10.0	10.9	-0.9	0.55	0.59	-0.04
1968	10.0	8.0	0.2	0.57	0.58	-0.01
1969	10.1	5.2	4.9	0.56	0.58	-0.02
1970	9.1	7.5	1.6	0.51	0.57	-0.06
1971	8.0	5.6	2.4	0.48	0.38	0.10
1972	7.7	6.0	1.7	0.44	0.41	0.03

MEAN GAS EXTENSIONS ERROR = 2.0
RMS ERROR = 2.6
MEAN ACTUAL = 7.2

MEAN OIL EXTENSIONS ERROR = 0.0
RMS ERROR = 0.05
MEAN ACTUAL = 0.52

TABLE 5.4: Historical Simulations of Gas and Oil Revisions

Year	(1) Simulated Gas Revisions (trillions cu.ft)	(2) Actual Gas Revisions (trillions cu.ft)	(3) Gas Revisions Error (1) - (2)	(4) Simulated Oil Revisions (billions of bbls)	(5) Actual Oil Revisions (billions of bbls)	(6) Oil Revisions Error (4) - (5)
1967	2.0	4.4	-2.4	1.96	1.82	0.14
1968	1.7	1.0	0.7	1.34	1.27	0.07
1969	1.5	-0.9	2.4	1.39	1.21	0.18
1970	1.2	-2.1	3.3	1.14	1.87	-0.73
1971	0.9	-1.0	1.9	1.05	1.51	-0.46
1972	0.6	-1.9	2.5	0.91	0.66	0.25

MEAN GAS REVISIONS ERROR = 1.4
RMS ERROR = 2.3
MEAN ACTUAL = -0.1

MEAN OIL REVISIONS ERROR = -0.09
RMS ERROR = 0.38
MEAN ACTUAL = 1.39

TABLE 5.5 : Historical Simulation of Gas and Oil Additions to Reserves

Year	(1) Simulated Gas Additions to Reserves (trillions cu.ft)	(2) Actual Gas Additions to Reserves (trillions cu.ft)	(3) Gas Additions to Reserves Error (1) - (2)	(4) Simulated Oil Additions to Reserves (billion bbls)	(5) Actual Oil Additions to Reserves (billion bbls)	(6) Oil Additions to Reserves Error (4) - (5)
1967	17.6	20.6	-3.0	2.85	2.69	0.16
1968	19.2	11.6	7.6	2.27	2.11	0.16
1969	17.8	8.0	9.8	2.14	2.03	0.11
1970	15.1	11.0	4.1	1.87	2.76	-0.89
1971	14.4	10.5	3.9	1.70	2.04	-0.34
1972	15.3	8.8	6.5	1.53	1.35	0.18

MEAN GAS ADDITIONS TO RESERVES ERROR = 4.8
RMS ERROR = 6.3
MEAN ACTUAL = 11.8

MEAN OIL ADDITIONS TO RESERVES ERROR = -0.10
RMS ERROR = 0.41
MEAN ACTUAL = 2.16

TABLE 5.6 : Historical Simulation of Gas and Oil Reserves

Year	(1) Simulated Gas Reserves (trillions cu.ft)	(2) Actual Gas Reserves (trillions cu.ft)	(3) Gas Reserves Error (1) - (2)	(4) Simulated Oil Reserves (billions bbls)	(5) Actual Oil Reserves (billion bbls)	(6) Oil Reserves Error (4) - (5)
1967	285	289	-4	29.5	24.0	5.5
1968	285	282	3	29.2	28.4	0.8
1969	282	269	13	28.9	27.5	1.4
1970	276	259	17	28.3	27.2	1.1
1971	269	246	23	27.7	26.3	1.4
1972	261	234	27	26.9	24.6	2.3

MEAN GAS RESERVES ERROR = 13
RMS ERROR = 17
MEAN ACTUAL = 263

MEAN OIL RESERVES ERROR = 2.1
RMS ERROR = 2.6
MEAN ACTUAL = 26.3

TABLE 5.7: Historical Simulation of U. S. Gas Production, Average Wellhead Price, and Average Wholesale Price

Year	(1) Simulated Production (trillion cu. ft.)	(2) Actual Production (trillion cu. ft.)	(3) Production Error (1) - (2)	(4) Simulated Average Wellhead Price (cents per Mcf)	(5) Actual Average Wellhead Price (cents per Mcf)	(6) Average Wellhead Price Error (4) - (5)	(7) Simulated Average Wholesale Price (cents per Mcf)	(8) Actual Average Wholesale Price (cents per Mcf)	(9) Wholesale Price Error (7) - (8)
1967	18.9	18.9	0.0	17.3	17.3	0.0	30.7	30.7	0.0
1968	20.1	19.9	0.2	17.4	17.5	-0.1	31.3	30.7	0.6
1969	20.9	21.3	-0.4	17.8	17.9	-0.1	31.8	31.5	0.3
1970	21.8	22.6	-0.8	18.5	18.3	0.2	33.2	33.1	0.1
1971	22.8	22.8	0.0	19.7	19.5	0.2	35.3	37.4	-2.1
1972	23.6	23.3	0.3	*	*	*	*	*	*

MEAN PRODUCTION ERROR = 0.1

RMS ERROR = 0.4

MEAN ACTUAL = 21.5

* Data not available for 1972

MEAN AVERAGE WELLHEAD PRICE ERROR = 0.05

RMS ERROR = 0.15

MEAN ACTUAL = 18.1

MEAN AVERAGE WHOLE PRICE ERROR = -0.19

RMS ERROR = 0.95

MEAN ACTUAL = 32.7

TABLE 5.8 : Historical Simulation of Northeast Gas Demand by Sector

Year	(1) Simulated Northeast Residential Demand (trillion cu.ft.)	(2) Actual Northeast Residential Demand (trillion cu.ft.)	(3) Demand Error (1) - (2)	(4) Simulated Northeast Industrial Demand (trillions cu.ft)	(5) Actual Northeast Industrial Demand (trillions cu.ft)	(6) Demand Error (4) - (5)
1967	2.02	2.12	-0.10	1.31	1.27	0.04
1968	2.08	2.23	-0.15	1.38	1.35	0.03
1969	2.14	2.32	-0.18	1.45	1.48	-0.03
1970	2.20	2.42	-0.22	1.53	1.49	0.04
1971	2.26	2.47	-0.21	1.61	1.52	0.09

MEAN NORTHEAST RESIDENTIAL DEMAND ERROR = -0.17
RMS ERROR = 0.18
MEAN ACTUAL = 2.31

MEAN NORTHEAST INDUSTRIAL DEMAND ERROR = 0.04
RSM ERROR = 0.05
MEAN ACTUAL = 1.42

TABLE 5.9 : Historical Simulation of North Central Gas Demand by Sector

Year	(1) Simulated North Central Residential Demand (trillion cu.ft.)	(2) Actual North Central Residential Demand (trillion cu.ft.)	(3) Demand Error (1) - (2)	(4) Simulated North Central Industrial Demand (trillion cu.ft.)	(5) Actual North Central Industrial Demand (trillion cu.ft.)	(6) Demand Error (4) - (5)
1967	1.99	1.97	0.02	1.56	1.59	-0.03
1968	2.07	2.17	-0.10	1.68	1.70	-0.02
1969	2.16	2.33	-0.17	1.80	1.86	-0.06
1970	2.23	2.42	-0.19	1.93	2.05	-0.12
1971	2.33	2.47	-0.14	2.07	2.11	-0.04

MEAN NORTH CENTRAL RESIDENTIAL DEMAND ERROR = -0.12
RMS ERROR = 0.14
MEAN ACTUAL = 2.27

MEAN NORTH CENTRAL INDUSTRIAL DEMAND ERROR = -0.05
RMS ERROR = 0.06
MEAN ACTUAL = 1.86

TABLE 5.10: Historical Simulation of Southeast Gas Demand by Sector

Year	(1) Simulated Southeast Residential Demand (trillion cu.ft.)	(2) Actual Southeast Residential Demand (trillion cu.ft.)	(3) Demand Error (1) - (2)	(4) Actual Southeast Industrial Demand (trillion cu.ft.)	(5) Actual Southeast Industrial Demand (trillion cu.ft.)	(6) Demand Error (4) - (5)
1967	0.47	0.46	0.01	0.87	0.86	0.01
1968	0.50	0.55	-0.05	0.92	0.92	0.00
1969	0.52	0.58	-0.06	0.98	1.01	-0.03
1970	0.54	0.60	-0.06	1.04	1.11	-0.07
1971	0.56	0.61	-0.05	1.10	1.09	0.01

MEAN SOUTHEAST RESIDENTIAL DEMAND ERROR = -0.14
RMS ERROR = 0.05
MEAN ACTUAL = 0.56

MEAN SOUTHEAST INDUSTRIAL DEMAND ERROR = -0.02
RMS ERROR = 0.03
MEAN ACTUAL = 1.00

TABLE 5.11 : Historical Simulation of South Central Gas Demand by Sector

Year	(1) Simulated South Central Residential Demand (trillion cu.ft.)	(2) Actual South Central Residential Demand (trillion cu.ft.)	(3) Demand Error (1) - (2)	(4) Simulated South Central Industrial Demand (trillion cu.ft.)	(5) Actual South Central Industrial Demand (trillion cu.ft.)	(6) Demand Error (4) - (5)
1967	0.89	0.93	-0.04	5.44	5.40	0.04
1968	0.91	1.11	-0.20	5.72	5.71	0.01
1969	0.92	1.14	-0.20	5.94	6.10	-0.16
1970	0.92	1.20	-0.28	6.09	6.48	-0.39
1971	0.90	1.00	-0.10	6.31	6.15	0.16

MEAN SOUTH CENTRAL RESIDENTIAL DEMAND ERROR = -0.17
RSM ERROR = 0.19
MEAN ACTUAL = 1.08

MEAN SOUTH CENTRAL INDUSTRIAL DEMAND ERROR = -0.07
RMS ERROR = 0.20
MEAN ACTUAL = 5.97

TABLE 5.12 : Historical Simulation of West Gas Demand by Sector

Year	(1) Simulated West Residential Demand (trillion cu.ft.)	(2) Actual West Residential Demand (trillion cu.ft.)	(3) Demand Error (1) - (2)	(4) Simulated West Industrial Demand (trillion cu.ft.)	(5) Actual West Industrial Demand (trillion cu.ft.)	(6) Demand Error (4) - (5)
1967	1.20	1.19	0.01	1.84	1.90	-0.06
1968	1.25	1.23	0.02	1.98	2.07	-0.09
1969	1.31	1.34	-0.04	2.00	2.06	-0.06
1970	1.35	1.37	-0.02	2.10	2.21	-0.11
1971	1.40	1.50	-0.10	2.13	2.11	0.02

MEAN WEST RESIDENTIAL DEMAND ERROR = -0.02
RMS ERROR = 0.05
MEAN ACTUAL = 1.32

MEAN WEST INDUSTRIAL DEMAND ERROR = -0.06
RMS ERROR = 0.08
MEAN ACTUAL = 2.07

TABLE 5.13: Historical Simulation of Total Gas Demand by Region

Year	(1) Simulated U.S. Lease and Plant Fuel Demand (trillion cu.ft.)	(2) Actual U.S. Lease and Plant Fuel Demand (trillion cu.ft.)	(3) Demand Error (1) - (2)	(4) Simulated Northeast Total* Demand (trillion cu.ft.)	(5) Actual Northeast Total* Demand (trillion cu.ft.)	(6) Demand Error (4) - (5)
1967	1.02	1.10	-0.08	3.33	3.40	-0.07
1968	1.12	1.20	-0.08	3.47	3.58	-0.11
1969	1.18	1.31	-0.13	3.60	3.80	-0.20
1970	1.25	1.36	-0.11	3.73	3.92	-0.19
1971	1.32	1.37	-0.05	3.88	4.00	-0.12

MEAN LEASE AND PLANT FUEL DEMAND ERROR = -0.09
RMS ERROR = 0.10
MEAN ACTUAL = 1.27

MEAN NORTHEAST TOTAL* DEMAND ERROR = -0.14
RMS ERROR = 0.15
MEAN ACTUAL = 3.74

*Includes lease and plant fuel demand.

TABLE 5.14: Historical Simulation of Total Gas Demand by Region

Year	(1) Simulated North Central Total* Demand (trillion cu.ft.)	(2) Actual North Central Total* Demand (trillion cu.ft.)	(3) Demand Error (1) - (2)	(4) Simulated Southeast Total Demand (trillion cu.ft.)	(5) Actual Southeast Total Demand (trillion cu.ft.)	(6) Demand Error (4) - (5)
1967	3.55	3.57	-0.02	1.34	1.32	0.02
1968	3.75	3.87	-0.12	1.42	1.47	-0.15
1969	3.96	4.20	-0.24	1.50	1.60	-0.10
1970	4.16	4.46	-0.30	1.59	1.70	-0.11
1971	4.40	4.58	-0.18	1.66	1.69	-0.03

*Includes lease and plant fuel demand.

MEAN NORTH CENTRAL TOTAL* DEMAND ERROR = -0.17
RMS ERROR = 0.20
MEAN ACTUAL = 4.14

MEAN SOUTHEAST TOTAL* DEMAND ERROR = -0.06
RMS ERROR = 0.07
MEAN ACTUAL = 1.56

TABLE 5.15: **Historical Simulation of Total Gas Demand by Region**

Year	(1) Simulated South Central Total Demand (trillions cu.ft.)	(2) Actual South Central Total* Demand (trillions cu.ft.)	(3) Demand Error (1) - (2)	(4) Simulated West Total * Demand (trillions cu.ft.)	(5) Actual West Total * Demand (trillions cu.ft.)	(6) Demand Error (4) - (5)
1967	7.20	7.26	-0.06	3.19	3.25	-0.06
1968	7.60	7.86	-0.26	3.37	3.46	-0.09
1969	7.90	8.40	-0.50	3.44	3.55	-0.11
1970	8.12	8.87	-0.75	3.58	3.74	-0.16
1971	8.40	8.37	0.03	3.65	3.75	-0.10

MEAN SOUTH CENTRAL TOTAL* DEMAND ERROR = -0.31
RMS ERROR = 0.42
MEAN ACTUAL = 8.15

MEAN WEST TOTAL* DEMAND ERROR = -0.11
RMS ERROR = 0.11
MEAN ACTUAL = 3.55

*Includes Lease and Plant Fuel Demand

TABLE 5.16: Historical Simulation of Northeast Oil Demand by Type

Year	(1) Simulated Northeast Distillate Demand (Million bbls)	(2) Actual Northeast Distillate Demand (Million bbls)	(3) Demand Error (1) - (2)	(4) Simulated Northeast Residual Demand (Million bbls)	(5) Actual Northeast Residual Demand (Million bbls)	(6) Demand Error (4) - (5)
1967	283	284	-1	390	397	-7
1968	283	285	-2	407	414	-7
1969	292	291	1	422	455	-33
1970	294	299	-5	439	526	-87
1971	302	296	6	457	544	-87

MEAN NORTHEAST DISTILLATE DEMAND ERROR = 0
RMS ERROR = 4
MEAN ACTUAL = 291

MEAN NORTHEAST RESIDUAL DEMAND ERROR = -44
RMS ERROR = 57
MEAN ACTUAL = 41

TABLE 5.17: Historical Simulation of North Central Oil Demand by Type

Year	(1) Simulated North Central Distillate Demand (Million bbls)	(2) Actual North Central Distillate Demand (Million bbls)	(3) Demand Error (1) - (2)	(4) Simulated North Central Residual Demand (Million bbls)	(5) Actual North Central Residual Demand (Million bbls)	(6) Demand Error (4) - (5)
1967	82.5	87.0	-4.5	51.3	50.2	1.1
1968	83.9	95.1	-11.2	52.8	52.0	0.8
1969	86.9	92.3	-5.6	56.0	53.9	2.1
1970	88.3	91.3	-3.0	56.9	61.7	-4.8
1971	92.6	92.4	0.2	61.0	58.7	2.3

MEAN NORTH CENTRAL DISTILLATE DEMAND ERROR = -4.8	MEAN NORTH CENTRAL RESIDUAL DEMAND ERROR = 0.3
RMS ERROR = 6.1	RMS ERROR = 2.6
MEAN ACTUAL = 91.6	MEAN ACTUAL = 55.3

Table 5.18: Historical Simulation of Southeast Oil Demand by Type

Year	(1) Simulated Southeast Distillate Demand (Million bbls)	(2) Actual Southeast Distillate Demand (Million bbls)	(3) Demand Error (1) - (2)	(4) Simulated Southeast Residual Demand (Million bbls)	(5) Actual Southeast Residual Demand (Million bbls)	(6) Demand Error (4) - (5)
1967	20.2	21.9	-1.7	63.1	59.3	3.8
1968	20.5	23.4	-2.9	66.1	61.8	4.3
1969	20.3	23.1	-2.8	70.4	69.0	1.4
1970	20.4	25.1	-4.7	73.6	82.6	-9.0
1971	20.6	23.0	-2.4	78.8	89.9	-11.1

MEAN SOUTHEAST DISTILLATE DEMAND ERROR = -2.9
RMS ERROR = 3.1
MEAN ACTUAL = 23.3

MEAN SOUTHEAST RESIDUAL DEMAND ERROR = -2.1
RMS ERROR = 6.9
MEAN ACTUAL = 72.5

TABLE 5.19: **Historical Simulation of South Central Oil Demand by Type**

Year	(1) Simulated South Central Distillate Demand (Million bbls)	(2) Actual South Central Distillate Demand (Million bbls)	(3) Demand Error (1) - (2)	(4) Simulated South Central Residual Demand (Million bbls)	(5) Actual South Central Residual Demand (Million bbls)	(6) Demand Error (4) - (5)
1967	2.3	1.9	0.4	24.3	26.6	-2.3
1968	2.7	2.4	0.3	24.0	27.6	-3.6
1969	3.2	4.2	-1.0	25.3	28.9	-3.6
1970	3.6	4.3	-0.7	24.8	30.2	-5.4
1971	4.2	4.6	-0.4	25.9	26.0	-0.1

MEAN SOUTH CENTRAL DISTILLATE DEMAND ERROR = -0.3
RMS ERROR = 0.6
MEAN ACTUAL = 3.5

MEAN SOUTH CENTRAL RESIDUAL DEMAND ERROR = -3.0
RMS ERROR = 3.5
MEAN ACTUAL = 27.9

TABLE 5.20: Historical Simulation of West Oil Demands by Type

Year	(1) Simulated West Distillate Demand (Million bbls)	(2) Actual West Distillate Demand (Million bbls)	(3) Demand Error (1) - (2)	(4) Simulated West Residual Demand (Million bbls)	(5) Actual West Residual Demand (Million bbls)	(6) Demand Error (4) - (5)
1967	17.3	18.5	-1.2	94.4	95.1	-0.7
1968	17.6	19.8	-2.2	96.2	101.7	-5.5
1969	17.3	18.3	-1.0	94.5	102.7	-8.2
1970	17.6	18.5	-0.9	91.5	90.9	0.6
1971	17.6	20.8	-3.2	90.1	106	-15.9

MEAN WEST DISTILLATE DEMAND ERROR = -1.7
RMS ERROR = 1.9
MEAN ACTUAL = 19.2

MEAN WEST RESIDUAL DEMAND ERROR = -5.9
RMS ERROR = 8.2
MEAN ACTUAL = 99.2

5.2. Use of the Model for Forecasting and Policy Analysis

Chapter 2 presents, in summary form, a set of simulations of the model through the year 1980 under alternative regulatory price policies. In this section, we examine these simulation results in more detail, so as to ascertain to what degree they are dependent upon assumptions on field and wholesale prices of oil, as well as on economic variables such as GNP and the rate of inflation.

In fact the forecasts in Chapter 2 are based on a specific set of values for the variables that are expected to hold during the 1970's. The important exogenous determinants of demand for gas and oil include state-by-state value added in manufacturing, population, income, and capital equipment additions. It is assumed that value added, income, and capital additions will grow at 4.2 percent per annum in terms of constant dollars.[3] We chose a conservative expected rate of growth of prices of 6.5 percent; the rate of inflation likely to prevail in the late 1970's is rather uncertain and is under considerable debate, and the rate of 6.5 percent simply represents a rough average of several inflation forecasts that have been made recently. Thus, value added, income and capacity grow at 10.7 percent in current dollar terms. It is assumed that the rate of growth of population 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). The domestic price of crude oil is assumed to remain constant at $6.50 per barrel in 1974 dollars for the remainder of the decade, and wholesale prices for both distillate and residual oil are also assumed to remain constant in real terms. Finally, average drilling costs are expected to increase at a rate of 3.3% per annum in real terms, in keeping with the trend of cost increases

[3]This assumption is based on the Data Resources Quarterly Economic Model forecast for the period 1972 to 1980.

over the late 1960's and early 1970's.

These values of the exogenous variables can be altered, and new values inserted into the model to produce new simulations that would indicate how the forecast results presented in Chapter 2 would depend on the particular assumptions that have been made. It is of particular interest to determine how these results depend on the assumptions made regarding the price of oil (the future of which is open to considerable speculation), as well as assumptions made regarding general economic conditions such as the growth in output and the rate of inflation. As an alternative to the set of "medium" assumptions for exogenous variables described above, we have chosen "high" and "low" assumptions for both oil prices and economic variables.

In contrast to the "medium" scenario for oil prices, we offer a "low" scenario in which the crude oil price declines by 25¢ per barrel each year (from \$6.50 in 1974 to \$5.00 in 1980) and a high scenario in which the price of crude oil increases from \$6.50 per barrel in 1974 to \$7.50 per barrel in 1980 (again in constant 1974 dollars). Wholesale oil prices (as well as prices for alternative fuels such as coal and electricity) are assumed to change in these scenarios at the same percentage rate as the crude oil price.

In contrast to the "medium" scenario for economic growth, we offer a 'low' scenario in which output variables (such as income, value added, and capital additions) grow at 2.5 percent in real terms with a rate of inflation of 4.0 percent, and a high scenario in which output variables grow at 5.0 percent in real terms and the rate of inflation is 8.0 percent.

5.2.1. Alternative Forecasts for Natural Gas and Oil

Alternative simulation results for the three oil price scenarios are shown in Table 5.21. In this table, it is assumed that the "FPC Regulation" policy on natural gas is in effect. Alternative results for the "Phased deregulation" price policy are shown in Table 5.22.

Table 5.21: Forecasts for "FPC Regulation" Under Three Oil Price Scenarios* Assuming Medium Economic Conditions

Year	New Discoveries	Total Additions to Reserves	Total Reserves	Supply of Production	Demand for Production	Excess Demand	New Contract Price	Average Wholesale Price
1972	$4.7^{4.7}_{4.7}$	$8.8^{8.8}_{8.8}$	$233.5^{233.5}_{233.5}$	$23.3^{23.3}_{23.3}$	$23.5^{23.5}_{23.5}$	$0.2^{0.2}_{0.2}$	$31.7^{31.7}_{31.7}$	$39.9^{39.9}_{39.9}$
1973	$10.2^{10.2}_{10.2}$	$17.5^{17.5}_{17.5}$	$228.4^{228.4}_{228.4}$	$23.7^{23.7}_{23.7}$	$24.3^{24.3}_{24.3}$	$0.6^{0.6}_{0.6}$	$34.7^{34.7}_{34.7}$	$41.6^{41.6}_{41.6}$
1974	$10.1^{10.1}_{10.1}$	$19.0^{19.0}_{19.0}$	$224.0^{224.0}_{224.0}$	$24.6^{24.6}_{24.6}$	$26.3^{26.3}_{26.3}$	$1.7^{1.7}_{1.7}$	$39.7^{39.7}_{39.7}$	$44.7^{44.7}_{44.7}$
1975	$13.3^{13.1}_{13.5}$	$22.1^{22.0}_{22.3}$	$222.1^{221.9}_{222.3}$	$25.4^{25.4}_{25.4}$	$28.8^{28.8}_{28.5}$	$3.4^{3.4}_{3.0}$	$44.8^{44.8}_{44.8}$	$48.7^{48.7}_{48.7}$
1976	$15.4^{15.1}_{15.7}$	$24.8^{24.6}_{25.1}$	$221.9^{221.6}_{222.5}$	$26.4^{26.4}_{26.4}$	$31.3^{31.3}_{30.4}$	$4.8^{4.9}_{3.9}$	$49.8^{49.8}_{49.8}$	$52.7^{52.7}_{52.7}$
1977	$17.6^{17.4}_{18.0}$	$27.4^{27.2}_{27.8}$	$223.7^{223.1}_{224.6}$	$27.4^{27.4}_{27.4}$	$33.6^{33.9}_{31.9}$	$6.2^{6.3}_{4.5}$	$54.9^{54.9}_{54.9}$	$57.2^{57.2}_{57.2}$
1978	$19.4^{19.0}_{20.0}$	$29.8^{29.4}_{30.4}$	$226.7^{225.8}_{228.2}$	$28.7^{28.6}_{28.7}$	$35.8^{36.5}_{33.1}$	$7.1^{7.8}_{4.4}$	$60.0^{60.0}_{60.0}$	$62.1^{62.1}_{62.1}$
1979	$19.9^{18.5}_{21.1}$	$30.8^{29.4}_{32.0}$	$229.6^{227.3}_{232.2}$	$30.1^{30.0}_{30.1}$	$37.9^{39.2}_{33.9}$	$7.8^{9.2}_{3.8}$	$65.1^{65.1}_{65.1}$	$67.2^{67.2}_{67.2}$
1980	$18.9^{16.9}_{21.6}$	$29.8^{27.5}_{32.7}$	$230.2^{225.8}_{235.5}$	$31.5^{31.4}_{31.7}$	$39.9^{42.0}_{34.4}$	$8.4^{10.6}_{2.7}$	$70.2^{70.2}_{70.2}$	$72.5^{72.5}_{72.5}$

*Superscript and subscript denote highest and lowest alternatives respectively.

Note: All quantities in trillions of cubic feet, and prices in cents/mcf.

Table 5.22: Forecasts for "Phased Deregulation" Under Three Oil Price Scenarios* Assuming Medium Economic Conditions

Year	New Discoveries	Total Additions to Reserves	Total Reserves	Supply of Production	Demand for Production	Excess Demand	New Contract Price	Average Wholesale Price
1972	$4.7^{4.7}_{4.7}$	$8.8^{8.8}_{8.8}$	$233.5^{233.5}_{233.5}$	$23.3^{23.3}_{23.3}$	$23.5^{23.5}_{23.5}$	$0.2^{0.2}_{0.2}$	$31.7^{31.7}_{31.7}$	$39.9^{39.9}_{39.9}$
1973	$10.2^{10.2}_{10.2}$	$17.5^{17.5}_{17.5}$	$228.4^{228.4}_{228.4}$	$23.7^{23.7}_{23.7}$	$24.3^{24.3}_{24.3}$	$0.7^{0.7}_{0.7}$	$34.7^{34.7}_{34.7}$	$41.6^{41.6}_{41.6}$
1974	$10.1^{10.1}_{10.1}$	$19.0^{19.0}_{19.0}$	$224.0^{224.0}_{224.0}$	$24.6^{24.6}_{24.6}$	$26.4^{26.4}_{26.4}$	$1.7^{1.7}_{1.7}$	$39.7^{39.7}_{39.7}$	$44.7^{44.7}_{44.7}$
1975	$16.7^{16.6}_{17.0}$	$25.6^{25.4}_{25.8}$	$224.2^{224.0}_{224.4}$	$26.8^{26.8}_{26.8}$	$28.7^{28.7}_{28.4}$	$1.9^{1.8}_{1.6}$	$64.7^{64.7}_{64.7}$	$52.8^{52.8}_{52.8}$
1976	$21.6^{21.4}_{22.0}$	$31.3^{31.1}_{31.6}$	$228.8^{228.5}_{229.4}$	$28.2^{28.2}_{28.2}$	$30.5^{30.6}_{29.6}$	$2.3^{2.4}_{1.5}$	$69.7^{69.7}_{69.7}$	$59.3^{59.3}_{59.3}$
1977	$25.4^{25.2}_{25.8}$	$35.8^{35.6}_{36.2}$	$237.1^{236.6}_{238.1}$	$29.2^{29.2}_{29.2}$	$32.0^{32.3}_{30.3}$	$2.8^{3.0}_{1.1}$	$74.8^{74.8}_{74.8}$	$65.4^{65.4}_{65.4}$
1978	$29.9^{29.7}_{30.0}$	$41.5^{41.4}_{41.6}$	$249.6^{248.9}_{250.6}$	$31.0^{31.0}_{31.0}$	$33.2^{33.9}_{30.4}$	$2.3^{2.9}_{-0.6}$	$80.0^{80.0}_{80.0}$	$71.9^{71.9}_{71.9}$
1979	$29.8^{29.3}_{29.8}$	$42.8^{42.4}_{42.7}$	$261.6^{260.5}_{262.4}$	$33.0^{32.9}_{33.0}$	$34.3^{35.4}_{30.1}$	$1.3^{2.5}_{-2.9}$	$85.1^{85.1}_{85.1}$	$78.2^{78.2}_{78.2}$
1980	$28.9^{25.5}_{29.3}$	$41.8^{38.4}_{42.0}$	$270.7^{266.3}_{271.6}$	$35.0^{35.0}_{35.1}$	$35.2^{37.1}_{29.4}$	$0.1^{2.1}_{-5.7}$	$90.3^{90.3}_{90.3}$	$84.2^{84.2}_{84.2}$

*Superscript and subscript denote highest and lowest alternatives respectively.

Note: All quantities in trillions of cubic feet, and prices in cents/mcf.

Under the "FPC Regulation" policy, new discoveries and additions to reserves are affected by the particular assumption made regarding oil prices, but there is less sensitivity under the "Phased Deregulation" policy. The reason for this is that when gas prices are low, as under regulation, a higher oil price serves as an incentive for additional exploratory drilling which results in significant additional gas discoveries. But when the price of gas is allowed to rise, as under "Phased Deregulation", there is already sufficient incentive for exploration on the extensive margin, and the additional incentive provided by the higher oil price is largely to increase directionality towards oil drilling.

In both the "FPC Regulation" and the "Phased Deregulation" policies the changes in oil prices add little more than 2 or 3 trillion cubic feet to total gas reserves. With small changes on reserves, the level of gas production remains almost the same under all three ceiling price scenarios. Demands for production, however, are quite sensitive to the price of oil. Under a scenario of low oil prices, for example, there is a shift in demand from natural gas to oil, and in 1980 the excess demand for natural gas is only 2.7 trillion cubic feet under the "FPC Regulation" policy. Under these oil price conditions, with "Phased Deregulation" the shortage of gas could be eased fairly soon. If oil prices decline in real terms by 5 percent per year, a field price increase for natural gas of only 10¢ or 15¢ in 1974 and 5¢ per year thereafter would be sufficient to clear markets by the end of the decade.

Alternative simulations for the three economic scenarios are shown for the "FPC Regulation" policy and the "Phased Deregulation" policy in Tables 5.23 and 5.24. Again there is relatively little variation in the level of production, but the demands for gas vary significantly. Under conditions of relatively slow economic growth, for example, the excess demand for natural gas in 1980 under the "FPC Regulation" policy is predicted to be 4.0 trillion cubic feet, in comparison with 8.4 trillion cubic feet under the medium economic economic scenario and 11.0 trillion cubic feet under the high economic

Table 5.23: "FPC Regulation" Forecasts Under Three Economic Scenarios* Assuming Medium Oil Price Conditions

Year	New Discoveries	Total Additions to Reserves	Total Reserves	Supply of Production	Demand for Production	Excess Demand	New Contract Price	Average Wholesale Price
1972	$4.7^{4.7}_{4.7}$	$8.8^{8.8}_{8.8}$	$233.5^{233.5}_{233.5}$	$23.3^{23.3}_{23.3}$	$23.5^{23.5}_{23.5}$	$0.2^{0.2}_{0.2}$	$31.7^{31.7}_{31.7}$	$39.9^{39.9}_{39.9}$
1973	$10.2^{10.2}_{10.2}$	$17.5^{17.5}_{17.5}$	$228.4^{228.4}_{228.4}$	$23.7^{23.7}_{23.7}$	$24.3^{24.3}_{24.3}$	$0.6^{0.6}_{0.6}$	$34.7^{34.7}_{34.7}$	$41.6^{41.6}_{41.6}$
1974	$10.1^{10.1}_{10.1}$	$19.0^{19.0}_{19.0}$	$224.0^{224.0}_{224.0}$	$24.6^{24.6}_{24.6}$	$26.3^{26.3}_{26.3}$	$1.7^{1.7}_{1.7}$	$39.7^{39.7}_{39.7}$	$44.7^{44.7}_{44.7}$
1975	$13.3^{13.2}_{13.4}$	$22.1^{22.0}_{22.2}$	$222.1^{222.0}_{222.2}$	$25.4^{25.4}_{25.4}$	$28.8^{28.9}_{28.5}$	$3.4^{3.5}_{3.1}$	$44.8^{44.8}_{44.8}$	$48.7^{48.7}_{48.7}$
1976	$15.4^{15.2}_{15.5}$	$24.8^{24.6}_{25.0}$	$221.9^{221.7}_{222.2}$	$26.4^{26.4}_{26.4}$	$31.3^{31.6}_{30.6}$	$4.8^{5.2}_{4.1}$	$49.8^{49.8}_{49.8}$	$52.7^{52.7}_{52.7}$
1977	$17.6^{17.5}_{17.8}$	$27.4^{27.3}_{27.6}$	$223.7^{223.3}_{224.2}$	$27.4^{27.4}_{27.4}$	$33.6^{34.2}_{32.3}$	$6.2^{6.9}_{4.9}$	$54.9^{54.9}_{54.9}$	$57.2^{57.2}_{57.2}$
1978	$19.4^{19.2}_{19.8}$	$29.8^{29.6}_{30.1}$	$226.7^{226.2}_{227.5}$	$28.7^{28.7}_{28.7}$	$35.8^{36.9}_{33.7}$	$7.1^{8.3}_{5.0}$	$60.0^{60.0}_{60.0}$	$62.1^{62.1}_{62.1}$
1979	$19.9^{19.1}_{20.7}$	$30.8^{30.0}_{31.6}$	$229.6^{228.3}_{231.1}$	$30.1^{30.0}_{30.1}$	$37.9^{39.6}_{34.8}$	$7.8^{9.6}_{4.7}$	$65.1^{65.1}_{65.1}$	$67.2^{67.2}_{67.2}$
1980	$18.9^{17.6}_{20.7}$	$29.8^{28.3}_{31.7}$	$230.2^{227.6}_{233.6}$	$31.5^{31.5}_{31.6}$	$39.9^{42.5}_{35.7}$	$8.4^{11.0}_{4.0}$	$70.2^{70.2}_{70.2}$	$72.5^{72.5}_{72.5}$

*Superscript and subscript denote highest and lowest alternatives respectively.

Note: All quantities in trillions of cubic feet, and prices in cents/mcf.

Table 5.24: "Phased Deregulation" Forecasts Under Three Economic Scenarios* Assuming Medium Oil Price Conditions

Year	New Discoveries	Total Additions to Reserves	Total Reserves	Supply of Production	Demand for Production	Excess Demand	New Contract Price	Average Wholesale Price
1972	$4.7^{4.7}_{4.7}$	$8.8^{8.8}_{8.8}$	$233.5^{233.5}_{233.5}$	$23.3^{23.3}_{23.3}$	$23.5^{23.5}_{23.5}$	$0.2^{0.2}_{0.2}$	$31.7^{31.7}_{31.7}$	$39.9^{39.9}_{39.9}$
1973	$10.2^{10.2}_{10.2}$	$17.5^{17.5}_{17.5}$	$228.4^{228.4}_{228.4}$	$23.7^{23.7}_{23.7}$	$24.3^{24.3}_{24.3}$	$0.7^{0.7}_{0.7}$	$34.7^{34.7}_{34.7}$	$41.6^{41.6}_{41.6}$
1974	$10.1^{10.1}_{10.1}$	$19.0^{19.0}_{19.0}$	$224.0^{224.0}_{224.0}$	$24.6^{24.6}_{24.6}$	$26.4^{26.4}_{26.4}$	$1.7^{1.7}_{1.7}$	$39.7^{39.7}_{39.7}$	$44.7^{44.7}_{44.7}$
1975	$16.7^{16.6}_{16.9}$	$25.6^{25.5}_{25.7}$	$224.2^{224.1}_{224.3}$	$26.8^{26.8}_{26.8}$	$28.7^{28.8}_{28.4}$	$1.9^{2.0}_{1.6}$	$64.7^{64.7}_{64.7}$	$52.8^{52.8}_{52.8}$
1976	$21.6^{21.5}_{21.8}$	$31.3^{31.2}_{31.5}$	$228.8^{228.6}_{229.1}$	$28.2^{28.2}_{28.2}$	$30.5^{30.8}_{29.8}$	$2.3^{2.7}_{1.6}$	$69.7^{69.7}_{69.7}$	$59.3^{59.3}_{59.3}$
1977	$25.4^{25.3}_{25.6}$	$35.8^{35.7}_{36.0}$	$237.1^{236.8}_{237.7}$	$29.2^{29.2}_{29.2}$	$32.0^{32.6}_{30.7}$	$2.8^{3.4}_{1.5}$	$74.8^{74.8}_{74.8}$	$65.4^{65.4}_{65.4}$
1978	$29.9^{29.8}_{29.9}$	$41.5^{41.4}_{41.6}$	$249.6^{249.2}_{250.1}$	$31.0^{31.0}_{31.0}$	$33.2^{34.3}_{31.1}$	$2.3^{3.4}_{0.1}$	$80.0^{80.0}_{80.0}$	$71.9^{71.9}_{71.9}$
1979	$29.8^{29.6}_{29.9}$	$42.8^{42.7}_{42.8}$	$261.6^{261.0}_{262.0}$	$33.0^{33.0}_{33.0}$	$34.3^{35.9}_{31.1}$	$1.3^{2.9}_{-1.9}$	$85.1^{85.1}_{85.1}$	$78.2^{78.2}_{78.2}$
1980	$28.9^{27.3}_{29.8}$	$41.8^{40.3}_{42.6}$	$270.7^{268.7}_{271.9}$	$35.0^{35.0}_{35.1}$	$35.2^{37.5}_{30.7}$	$0.1^{2.5}_{-4.4}$	$90.3^{90.3}_{90.3}$	$84.2^{84.2}_{84.2}$

* Superscript and subscript denote highest and lowest alternatives respectively.

Note: All quantities in trillions of cubic feet, and prices in cents/mcf.

scenario. This is not unreasonable in terms of direction; any decline in the long-term rate of growth for the American economy ought to reduce the rate of growth of demand for natural gas (as well as for other energy resources). If the rate of economic growth is slower than we have anticipated in our medium economic scenario, then smaller increases in the field price of gas will be necessary to clear natural gas markets by the end of the decade.

The econometric model can also be used to forecast the impact of alternative natural gas regulatory policies on the supply and demand for oil. This impact is of course also dependent upon the particular values chosen for the exogenous variables. Forecasts are presented here for new discoveries, and total additions to reserves, for crude oil under alternative regulatory policies for natural gas, alternative oil prices, and alternative scenarios for economic growth. Table 5.25 shows results for the "FPC Regulation" and "Phased Deregulation" gas price policies under the three alternative oil price scenarios and the three alternative economic scenarios. As can be seen, total additions to oil reserves grow by about 30 percent over the eight-year pariod 1972-1980 under both the "FPC Regulation" policy and the "Phased Deregulation" policy. Changes in reserves are slightly dependent on assumptions made about oil prices and economic variables (a 15 percent increase in the price of crude oil, for example, results in only a 3 percent increase in additions to oil reserves by the end of the decade). One might expect both an increase in well drilling and an increase in oil discoveries to result from higher oil prices. There is an increase in well drilling, but a slightly lower oil success ratio combined with only a small increase in discovery size (due in part to depletion) results in only modest increases in discoveries.

Alternative forecasts for wholesale oil demand under the "FPC Regulation" policies are shown in Table 5.26 through 5.29. As can be seen from those tables, the demand for oil is dependent on future oil prices

Table 5.25: Oil Supply Under Alternative Polic[illegible] Prices and Economic Conditions*

Year	"FPC Regulation Gas Policy--"Medium Economic Assumption--Alternative Oil Prices (Discoveries)	(Total Additions)	"FPC Regulation" Gas Policy--"Medium" Oil Prices--Alternative Economic Assumptions (Discoveries)	(Total Additions)	"Phased Deregulation Gas Policy--"Medium" Economic Assumptions--Alternative Oil Prices (Discoveries)	(Total Additions)	"Phased Deregulation" Policy--"Medium" Oil Prices--Alternative Economic Assumptions (Discoveries)	(Total Additions)
1972	$0.27^{0.27}_{0.27}$	$1.35^{1.35}_{1.35}$	$0.27^{0.27}_{0.27}$	$1.35^{1.35}_{1.35}$	$0.27^{0.27}_{0.27}$	$1.35^{1.35}_{1.35}$	$0.27^{0.27}_{0.27}$	$1.35^{1.35}_{1.35}$
1973	$0.34^{0.34}_{0.34}$	$1.21^{1.21}_{1.21}$	$0.34^{0.34}_{0.34}$	$1.21^{1.21}_{1.21}$	$0.34^{0.34}_{0.34}$	$1.21^{1.21}_{1.21}$	$0.34^{0.34}_{0.34}$	$1.21^{1.21}_{1.21}$
1974	$0.36^{0.36}_{0.36}$	$1.26^{1.26}_{1.26}$	$0.36^{0.36}_{0.36}$	$1.26^{1.26}_{1.26}$	$0.36^{0.36}_{0.36}$	$1.26^{1.26}_{1.26}$	$0.36^{0.36}_{0.36}$	$1.26^{1.26}_{1.26}$
1975	$0.54^{0.54}_{0.54}$	$1.59^{1.59}_{1.59}$	$0.54^{0.54}_{0.54}$	$1.59^{1.59}_{1.59}$	$0.54^{0.54}_{0.54}$	$1.59^{1.59}_{1.59}$	$0.54^{0.54}_{0.54}$	$1.59^{1.59}_{1.59}$
1976	$0.47^{0.48}_{0.46}$	$1.37^{1.38}_{1.37}$	$0.47^{0.47}_{0.47}$	$1.37^{1.37}_{1.37}$	$0.49^{0.49}_{0.48}$	$1.39^{1.39}_{1.39}$	$0.49^{0.49}_{0.48}$	$1.39^{1.39}_{1.38}$
1977	$0.60^{0.63}_{0.58}$	$1.69^{1.71}_{1.66}$	$0.60^{0.62}_{0.59}$	$1.69^{1.70}_{1.69}$	$0.61^{0.63}_{0.59}$	$1.71^{1.73}_{1.68}$	$0.61^{0.63}_{0.60}$	$1.71^{1.72}_{1.69}$
1978	$0.62^{0.66}_{0.57}$	$1.61^{1.66}_{1.55}$	$0.62^{0.64}_{0.59}$	$1.61^{1.64}_{1.58}$	$0.60^{0.64}_{0.54}$	$1.61^{1.66}_{1.55}$	$0.60^{0.62}_{0.57}$	$1.61^{1.64}_{1.58}$
1979	$0.61^{0.64}_{0.54}$	$1.77^{1.82}_{1.68}$	$0.61^{0.63}_{0.57}$	$1.77^{1.80}_{1.72}$	$0.55^{0.60}_{0.48}$	$1.72^{1.80}_{1.62}$	$0.55^{0.58}_{0.50}$	$1.72^{1.77}_{1.67}$
1980	$0.58^{0.60}_{0.54}$	$1.70^{1.75}_{1.61}$	$0.58^{0.59}_{0.56}$	$1.70^{1.73}_{1.66}$	$0.55^{0.58}_{0.45}$	$1.66^{1.73}_{1.51}$	$0.55^{0.58}_{0.49}$	$1.66^{1.71}_{1.57}$

*Superscripts and subscripts denote highest and lowest alternatives respectively.

Note: All discoveries and additions are in billions of barrels.

Table 5.26: Forecasts for Oil Demand Under Three Oil Price Scenarios Assuming "FPC Regulation" and Medium Economic Conditions (in 10^6 Barrels)

Region	Residential-Commercial Demand NE	NC	SE	SC	W	Industrial Demand NE	NC	SE	SC	W
1975	381^{381}_{381}	131^{131}_{131}	$24.5^{24.6}_{24.6}$	$7.53^{7.53}_{7.53}$	$19.2^{19.2}_{19.2}$	719^{719}_{719}	$97.0^{97.0}_{97.0}$	$98.4^{98.4}_{98.4}$	$32.5^{32.5}_{32.5}$	$96.7^{96.7}_{96.7}$
1976	390^{390}_{396}	136^{136}_{139}	$24.9^{25.1}_{25.2}$	$8.12^{8.12}_{8.24}$	$19.2^{19.2}_{19.5}$	760^{760}_{770}	109^{109}_{109}	103^{103}_{104}	$33.8^{33.8}_{34.0}$	$96.5^{96.5}_{97.0}$
1977	406^{404}_{421}	145^{144}_{151}	$25.2^{25.7}_{26.1}$	$8.91^{8.87}_{9.22}$	$19.6^{19.5}_{20.2}$	818^{814}_{842}	123^{122}_{124}	108^{108}_{109}	$35.0^{34.9}_{35.7}$	$97.5^{97.4}_{98.8}$
1978	429^{423}_{456}	156^{153}_{167}	$26.4^{26.5}_{27.4}$	$9.93^{9.81}_{10.5}$	$20.2^{19.9}_{21.3}$	891^{881}_{935}	138^{138}_{141}	114^{114}_{116}	$37.2^{36.9}_{38.4}$	$99.0^{98.5}_{101}$
1979	460^{447}_{501}	171^{165}_{188}	$27.6^{27.6}_{29.1}$	$11.2^{10.9}_{12.0}$	$21.2^{20.6}_{22.9}$	984^{962}_{1051}	157^{155}_{161}	120^{120}_{123}	$39.4^{38.8}_{41.3}$	102^{100}_{105}
1980	498^{476}_{557}	189^{179}_{213}	$29.1^{28.9}_{31.1}$	$12.7^{12.2}_{13.9}$	$22.4^{21.5}_{24.8}$	1094^{1057}_{1191}	177^{175}_{183}	127^{126}_{130}	$42.6^{41.6}_{45.4}$	105^{103}_{109}

*Superscript and subscript denote highest and lowest alternatives, respectively.

Table 5.27: Forecasts for Oil Demand Under Three Economic Scenarios*
Assuming "FPC Regulation" and Medium Oil Price Conditions (in 10^6 Barrels)

	Residential-Commercial Demand					Industrial Demand				
Region	NE	NC	SE	SC	W	NE	NC	SE	SC	W
1975	381^{396}_{355}	131^{138}_{119}	$24.5^{24.7}_{24.5}$	$7.53^{7.54}_{7.53}$	$19.2^{19.3}_{19.2}$	719^{736}_{690}	$97.0^{106}_{80.5}$	$98.3^{101}_{94.1}$	$32.5^{34.0}_{29.8}$	$96.7^{99.0}_{92.6}$
1976	390^{413}_{352}	136^{147}_{118}	$24.9^{25.2}_{24.9}$	$8.12^{8.10}_{8.16}$	$19.2^{19.2}_{19.2}$	760^{786}_{720}	$109^{123}_{84.1}$	$103^{107}_{97.0}$	$33.8^{36.0}_{30.0}$	$96.5^{99.9}_{90.8}$
1977	406^{437}_{357}	145^{159}_{121}	$25.5^{25.9}_{25.6}$	$8.91^{8.84}_{9.03}$	$19.6^{19.5}_{19.7}$	818^{851}_{766}	$123^{143}_{88.4}$	108^{114}_{100}	$35.0^{38.0}_{30.0}$	$97.5^{102}_{90.0}$
1978	429^{469}_{367}	156^{175}_{126}	$26.4^{26.8}_{26.6}$	$9.93^{9.80}_{10.2}$	$20.2^{20.0}_{20.5}$	891^{933}_{828}	$138^{167}_{93.7}$	114^{121}_{104}	$37.2^{41.2}_{30.9}$	$99.0^{105}_{89.4}$
1979	460^{511}_{384}	171^{195}_{134}	$27.6^{28.0}_{27.9}$	$11.2^{11.0}_{11.6}$	$21.2^{20.8}_{21.7}$	984^{1035}_{908}	$157^{194}_{99.8}$	120^{129}_{107}	$39.4^{44.5}_{31.6}$	$102^{109}_{89.8}$
1980	498^{561}_{408}	189^{219}_{144}	$29.1^{29.5}_{29.6}$	$12.7^{12.3}_{13.2}$	$22.4^{21.9}_{23.3}$	1094^{1156}_{1006}	177^{225}_{107}	127^{138}_{111}	$42.6^{49.0}_{33.2}$	$105^{114}_{90.4}$

*Superscript and subscript denote highest and lowest alternatives, respectively.

Table 5.28: Forecasts for Oil Demand Under Three Oil Price Scenarios* Assuming "Phased Deregulation" and Medium Economic Conditions in 10^6 Barrels)

	Residential-Commercial Demand					Industrial Demand				
Region	NE	NC	SE	SC	W	NE	NC	SE	SC	W
1975	380^{380}_{380}	131^{131}_{131}	$24.5^{24.6}_{24.6}$	$7.45^{7.45}_{7.45}$	$19.2^{19.2}_{19.2}$	717^{717}_{717}	$97.0^{97.0}_{97.0}$	$98.3^{98.4}_{98.4}$	$32.4^{32.4}_{32.4}$	$96.7^{96.7}_{96.7}$
1976	397^{397}_{403}	140^{140}_{143}	$25.3^{25.5}_{25.6}$	$8.37^{8.37}_{8.50}$	$19.9^{19.9}_{20.1}$	785^{785}_{795}	109^{109}_{109}	103^{104}_{104}	$33.9^{33.9}_{34.2}$	$97.0^{97.0}_{97.5}$
1977	426^{424}_{441}	154^{153}_{160}	$26.7^{26.9}_{27.3}$	$9.68^{9.65}_{10.0}$	$21.2^{21.1}_{21.8}$	883^{880}_{908}	123^{122}_{124}	109^{109}_{110}	$35.5^{35.5}_{36.3}$	$98.8^{98.6}_{100.}$
1978	464^{458}_{491}	172^{170}_{183}	$28.5^{28.6}_{29.5}$	$11.3^{11.2}_{11.9}$	$23.0^{22.8}_{24.1}$	1007^{997}_{1051}	138^{138}_{141}	115^{115}_{117}	$38.2^{37.9}_{39.5}$	101^{101}_{103}
1979	513^{500}_{550}	195^{189}_{212}	$30.7^{30.7}_{32.2}$	$13.2^{13.0}_{14.1}$	$25.3^{24.8}_{27.0}$	1160^{1138}_{1227}	157^{155}_{161}	122^{122}_{125}	$40.9^{40.4}_{42.9}$	105^{104}_{108}
1980	572^{550}_{631}	221^{211}_{245}	$33.4^{33.2}_{35.3}$	$15.3^{15.1}_{16.7}$	$27.8^{27.0}_{30.4}$	1337^{1300}_{1434}	177^{175}_{183}	130^{129}_{134}	$44.6^{43.7}_{47.5}$	109^{107}_{114}

*Superscript and subscript denote highest and lowest alternatives, respectively.

Table 5.29: Forecasts for Oil Demand Under Three Economic Scenarios*
Assuming "Phased Deregulation" and Medium Oil Price Conditions
in 10^6 Barrels)

	Residential-Commercial					Industrial Demand				
Region	NE	NC	SE	SC	W	NE	NC	SE	SC	W
1975	380^{396}_{354}	131^{138}_{118}	$24.5^{24.6}_{24.6}$	$7.45^{7.45}_{7.45}$	$19.2^{19.2}_{19.2}$	717^{734}_{688}	$97.0^{106}_{80.5}$	$98.3^{101}_{94.0}$	$32.4^{33.9}_{29.8}$	$96.7^{99.0}_{92.6}$
1976	397^{420}_{360}	140^{151}_{122}	$25.3^{25.5}_{25.6}$	$8.37^{8.37}_{8.50}$	$19.9^{19.9}_{20.1}$	785^{810}_{745}	$109^{123}_{84.1}$	$103^{107}_{97.3}$	$33.9^{36.2}_{30.2}$	$97.0^{100}_{91.3}$
1977	426^{457}_{376}	154^{169}_{130}	$26.7^{26.9}_{27.3}$	$9.68^{9.65}_{10.0}$	$21.2^{21.1}_{21.8}$	883^{917}_{832}	$123^{143}_{88.4}$	109^{114}_{101}	$35.5^{38.6}_{30.6}$	$98.8^{103}_{91.2}$
1978	464^{504}_{402}	172^{192}_{142}	$28.5^{28.6}_{29.5}$	$11.3^{11.2}_{11.9}$	$23.0^{22.8}_{24.1}$	1007^{1049}_{944}	$138^{167}_{93.7}$	115^{122}_{105}	$38.2^{42.2}_{31.9}$	$101^{107}_{91.6}$
1979	513^{564}_{437}	195^{219}_{158}	$30.7^{30.7}_{32.2}$	$13.2^{13.0}_{14.1}$	$25.3^{24.8}_{27.0}$	1160^{1211}_{1084}	$157^{194}_{99.8}$	122^{131}_{109}	$40.9^{46.1}_{33.2}$	$105^{112}_{92.9}$
1980	572^{635}_{481}	221^{251}_{176}	$33.4^{33.2}_{35.3}$	$15.3^{15.1}_{16.7}$	$27.8^{27.0}_{30.4}$	1337^{1399}_{1249}	177^{225}_{107}	130^{141}_{114}	$44.6^{51.2}_{35.3}$	$109^{119}_{94.6}$

*Superscript and subscript denote highest and lowest alternatives, respectively.

and rates of economic growth, as well as on gas regulatory policies. These dependencies vary, of course, from region to region as well as between residential and industrial demand. However, oil demand generally shows more long-term responsiveness to the oil price in the Northeast and North Central regions of the country, and less responsiveness in the Southeast, South Central, and West regions. Oil demand shows a great deal more responsiveness to the price of gas, and can be seen by comparing Tables 5.26 and 5.28 and Tables 5.27 and 5.29. There is also greater dependence on economic growth variables in the Northeast and North Central regions than elsewhere for residential demand, and greater dependence on growth in all regions for industrial than for residential demand.

These patterns could have been predicted from the regression equations alone. Those growth variables accounting for a large fraction of the explained variance in the regression equations also have the greatest effect on the simulations. The results are reasonable in view of the magnitudes of price increases and economy-wide growth in the past.

5.5.2. Simulations of Alternative Offshore Leasing Policies

Government policies affecting the natural gas industry include not only field price regulation but also the leasing of offshore lands for exploration, development, and production. Alternative offshore leasing policies can be simulated with the econometric model since the number of acres leased each year is an exogenous policy variable in the "offshore submodel", and affects (through reserve additions) offshore production.

All of the simulation results presented above are based on the assumption that two million acres of offshore lands would be leased each year by the Department of Interior's Bureau of Land Management. Simulation results for additions to reserves and production are shown in Table 5.30 for the alternative leasing policies of one million and three million acres per year.

Table 5.30 : Results with Alternative Leasing Policies*

	"FPC Regulation" Policy		"Phased Deregulation" Policy	
	Additions to Reserves	Production	Additions to Reserves	Production
1974	$19.0^{19.1}_{18.9}$	$24.6^{24.6}_{24.6}$	$19.0^{19.1}_{18.9}$	$24.6^{24.6}_{24.6}$
1975	$22.1^{22.4}_{21.8}$	$25.4^{25.4}_{25.4}$	$25.6^{26.0}_{25.1}$	$26.8^{26.8}_{26.8}$
1976	$24.8^{25.4}_{24.0}$	$26.4^{26.4}_{26.4}$	$31.3^{32.1}_{30.3}$	$28.2^{28.2}_{28.2}$
1977	$27.4^{28.3}_{26.3}$	$27.4^{27.4}_{27.4}$	$35.8^{36.9}_{34.5}$	$29.2^{29.2}_{29.2}$
1978	$29.8^{30.9}_{28.5}$	$28.7^{28.7}_{28.6}$	$41.5^{42.6}_{39.9}$	$31.0^{31.0}_{30.9}$
1979	$30.8^{32.1}_{29.1}$	$30.1^{30.2}_{29.9}$	$42.8^{44.0}_{41.2}$	$33.0^{33.1}_{32.8}$
1980	$29.8^{31.5}_{27.5}$	$31.5^{31.8}_{31.2}$	$41.8^{42.9}_{40.3}$	$35.0^{35.3}_{34.7}$

* Superscript denotes 3 million acreas leasing annually and subscript denotes 1 million acreas leasing annually.

These results are presented for the "FPC Regulation" and "Phased Deregulation" field price policies, and in both cases "medium" oil price and economic conditions are assumed.

As can be seen from the table, additions to reserves and production show very little sensitivity to the number of offshore acres leased annually. An increase of one million acres in offshore leasing results in only a 1 percent increase in production of gas by 1980. This is significant because it has been claimed that more liberal offshore leasing policies will serve to ameliorate the shortage of gas caused by stringent field price regulation. In fact the model indicates that expansion of offshore leasing will not significantly reduce future shortages of gas.

5.3. The Demand Function for Liquified Natural Gas

The model has other forecasting and analysis applications besides those dealing with FPC field price regulation. As an example, the econometric model can be used to determine the demand function for Liquified Natural Gas (or another substitute for natural gas) in different regions of the country under one or another particular field price regulatory policy. We explain in detail here how the LNG demand function is calculated, and present demand schedules for different regions of the country under the "FPC Regulation" price policy.

The demand function for Liquified Natural Gas is assumed to be the excess demand persisting after the supply of natural gas from existing sources, both onshore and offshore, has been parceled out regionally. Thus, the LNG demand function is obtained by horizontally subtracting supply from the demand function for natural gas in each region. This LNG demand function is of course <u>conditional on the particular FPC price policy that is in effect</u>.

It should be noted, however, that the demand function for natural gas that is relevent for this purpose is not the estimated equation in a particular region, but must be derived from simulations of the entire model. There are several reasons for this. First, the model determines demand in individual states through regional demand equations that contain exogenous variables (population, income, etc.) that, along with dummy variables, vary from state to state. This means that we cannot determine a price-quantity relationship for wholesale gas demand on a regional basis independent from exogenous and dummy variables. Furthermore, residential/commercial and industrial demand equations have been estimated separately, and there is no way of "summing" across states or across residential/commercial and industrial demand to form an aggregate demand function that is a relationship between quantity demanded and wholesale price. Finally, the input-output table in the model allocates flows of gas between producing and consuming regions, not to the level of individual states. By calculating simulated values of gas demand by state and by residential/commercial and industrial markets, along with regional supplies obtained after feeding in relevant values of the exogenous variables and other policy parameters, we estimate a weighted-average wholesale price and wholesale demand by region for each price simulation. By performing enough simulations (varying the regulated field price across simulations), sufficient "data points" can be obtained for price and demand to allow estimation of regional demand functions (i.e., quantity demanded in the region versus the weighted-average wholesale price).

Our estimation procedure, then, begins by obtaining total demand schedules for natural gas by region, for the three important excess demand regions, Northeast, North Central, and West. These demand schedules are of the form:

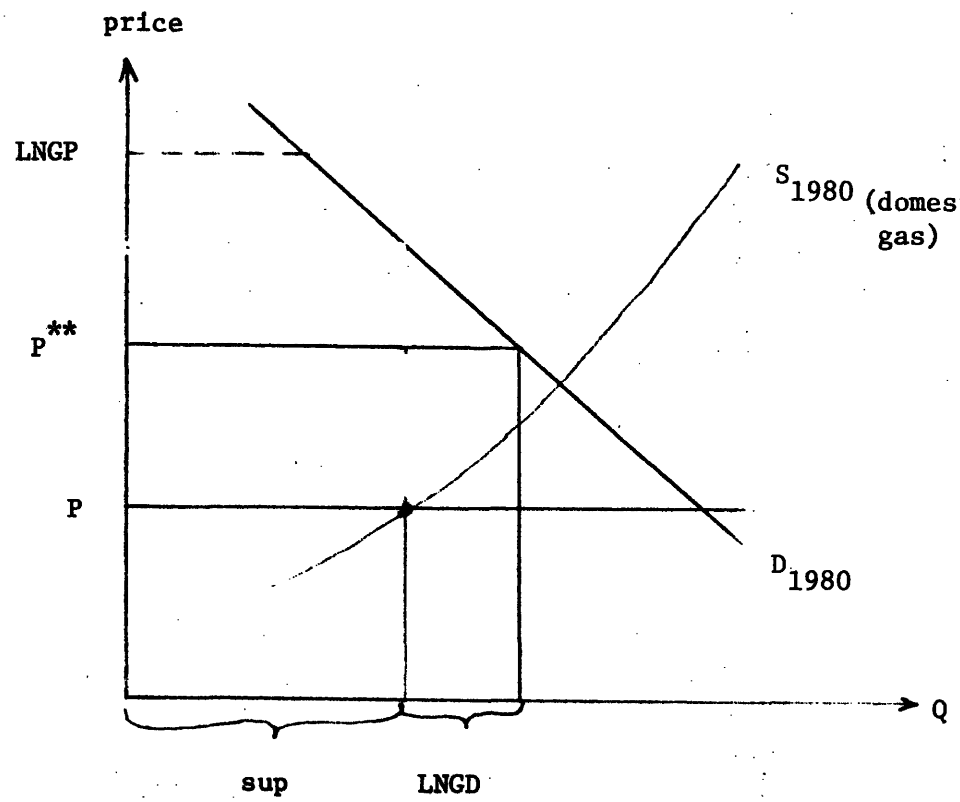
$$XXWD = c_0 + c_1 XXWP$$

where XX represents a regional prefix, and WD and WP are the wholesale demand and wholesale price respectively. Thus the schedule is a relationship between total quantity and weighted-average price. Once equation (1) has been estimated by a regression equation on the data derived for each region, we determine the LNG schedule by simulating the following equation for each region of the country:[4]

---

[4]Equation (2) is simply another way of writing equation (1), except that total gas demand is set equal to supply plus excess demand, and this excess demand is assumed to be the demand for LNG. P is the wholesale price (resulting in excess demand LNGD) and P^{**} is the weighted-average price that results from P and the LNG price for that portion of (excess) demand. The equation is illustrated graphically in Figure 5.1. Note that in the figure, LNGP is the price at which LNG can be sold to that volume exceeding SUP and satisfying total demand at P^{**}. By simulating equation (2) we find pairs of values (LNGP, LNGD) that make up the LNG demand schedule.

Figure 5.1 Calculation of LNG Demand Schedule



$$XXLNGD + XXSUP = c_0 +$$

$$c_1[((XXLNGD \cdot XXLNGP) + (XXSUP \cdot XXP)) / (XXLNGD + XXSUP)] \bullet \quad (2)$$

The coefficients c_0 and c_1 in equation (2) take on the values of the regression estimates of equation (1) in each region of the country. It is also important to remember that the data from which equation (1) is estimated are simulation results that apply to a single year, and that the simulation of equation (2) and the resulting LNG demand schedule should apply to the same year.

We have estimated equation (1) over the Northeast, North Central, and West regions, using simulation results for the year 1980. These regression results are shown below as equations (3), (4), and (5). Note that the number of observations used in each regression is simply equal to the number of states in the particular region.

Northeast:

$$\underset{}{NEWD} = \underset{(90.9)}{7.18\text{x}10^6} - \underset{(-32.0)}{21{,}600NEWP} \quad (3)$$

$R^2 = 0.99$ $F = 1023$ $S.E. = 5.29\text{x}10^4$

North Central:

$$NCWD = \underset{(76.5)}{1.261\text{x}10^7} - \underset{(-28.9)}{46{,}500\ NCWP} \quad (4)$$

$R^2 = 0.99$ $F = 834$ $S.E. = 1.18\text{x}10^5$

West:

$$WWD = \underset{(96.9)}{6.73\text{x}10^6} - \underset{(-29.7)}{22{,}300WWP} \quad (5)$$

$R^2 = 0.99$ $F = 884$ $S.E. = 4.89\text{x}10^4$

At this point we determine the LNG demand schedule in the Northeast, for example, by taking the estimated values of c_0 and c_1 from equation (3), substituting them in equation (2) and simulating equation (2) for various LNG prices to determine LNG demand at those LNG prices in 1980. This is repeated for the North Central and West regions to determine three regional LNG demand schedules, all of which apply, of course, to the "FPC Regulation" field price regulatory policy. The schedules are shown in Table 5.31. It is interesting to note that the table indicates that the greatest demand for LNG will be in the North Central region, ranging from 5.5 trillion cubic feet at a price of 50¢ per Mcf to 2.2 trillion cubic feet annually at a price of $2.50.

Although the magnitudes of LNG differ considerably from region to region, the demand elasticities do not differ widely. We have calculated average demand elasticities based on the schedules of Table 5.30 equal to -0.44 for the Northeast, -0.61 for the North Central, and -0.43 for the West. Of course these demand elasticities and the schedules from which they were derived are completely dependent on a particular natural gas regulatory policy, and an alternative policy would result in different LNG demand schedules and possibly different elasticities of demand.

5.4. Summary

The derivation of the LNG demand schedule is just one example of how the model can be applied to forecasting and policy analysis problems. There are other interesting applications. For example, it is straightforward to use the model to measure the gains and losses that would result from Federal allocation policies that shift gas from one region of the country to another. This would involve adding equations to demand regions according to criteria other than the input-output matrix (this would be similar to the method used now to allocate gas between intra- and interstate markets). Another application example would be to measure gains and losses resulting from the regulation of <u>intrastate</u>

TABLE 5.31: Regional LNG Demand Schedules for the Year 1980
Under "Status Quo" Policy
(Demands in trillions of cu. ft.)

Price of LNG (cents per mcf)	Northeast Demand	North Central Demand	West Demand
50.	0.3441	5.500	0.2113
55.	0.3361	5.364	0.2066
60.	0.3286	5.231	0.2021
65.	0.3213	5.101	0.1977
70.	0.3143	4.974	0.1935
75.	0.3076	4.850	0.1895
80.	0.3012	4.729	0.1857
85.	0.2950	4.611	0.1820
90.	0.2890	4.496	0.1784
95.	0.2833	4.383	0.1750
100.	0.2778	4.274	0.1717
105.	0.2725	4.167	0.1685
110.	0.2673	4.064	0.1654
115.	0.2624	3.963	0.1624
120.	0.2576	3.865	0.1596
125.	0.2530	3.770	0.1568
130.	0.2486	3.678	0.1541
135.	0.2443	3.588	0.1515
140.	0.2401	3.501	0.1490
145.	0.2361	3.417	0.1466
150.	0.2322	3.335	0.1442
155.	0.2284	3.256	0.1420
160.	0.2247	3.180	0.1398
165.	0.2212	3.105	0.1376
170.	0.2177	3.033	0.1355
175.	0.2144	2.964	0.1335
180.	0.2111	2.897	0.1316
185.	0.2080	2.831	0.1297
190.	0.2049	2.768	0.1278
195.	0.2019	2.707	0.1260
200.	0.1991	2.648	0.1243
205.	0.1962	2.591	0.1226
210.	0.1935	2.536	0.1209
215.	0.1908	2.482	0.1193
220.	0.1883	2.430	0.1177
225.	0.1857	2.380	0.1162
230.	0.1833	2.332	0.1147
235.	0.1809	2.285	0.1132
240.	0.1785	2.239	0.1118
245.	0.1763	2.195	0.1104
250.	0.1740	2.153	0.1091

gas so as to make its price always equal to the interstate price. Such a policy would change the allocation of supplies and would also affect the levels of supply and demand, and the extent of the impact could be measured using the model.[5]

Detailed econometric models of particular industries have been applied to forecasting and policy analysis only over the past few years, and have lagged the application of macroeconometric models. Industry models have the same limitations as macroeconometric models--their forecasts are subject to the errors that result from model misspecification, unexplained variance in regression equations, imprecise coefficient estimates and an inability to accurately predict exogenous variables. This model of the natural gas industry must also have these limitations. On the other hand, the model provides a consistent framework that simultaneously accounts for the interactions among producers, pipelines, and consumers in the gas industry and determine its behavior with respect to regulation and other government policies. Only the decade of the 1970's will tell whether its forecasts were accurate and whether its lessons on regulatory policy were effective.

---

[5]Individuals who desire to access the model for these and other simulation experiments can write to the authors at M.I.T., Cambridge, Massachusetts, U.S.A. for information on how to do so.

BIBLIOGRAPHY

1. Adelman, M.A. and M. Baughman, "Progress Report on the Estimation of the Gas Supply Cost Function". Unpublished memorandum to the Massachusetts Institute of Technology Energy Laboratory, July 2, 1973.

2. Alchian, A., "Costs and Outputs", in M. Abramowitz, ed., Allocation of Economic Resources. Stanford: Stanford University Press, 1958.

3. American Petroleum Institute, "Sales of Heating Oil, Grade No. 2, by States, 1937 - 1970", in Petroleum Facts and Figures.

4. American Petroleum Institute, American Gas Association, Committee on Natural Gas Reserves, The Special Report on Louisiana Offshore (Zones 2, 3, 4), 1954 - 1972. Unpublished material.

5. American Petroleum Institute/American Gas Association/Canadian Petroleum Association, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas. Published annually, 1966 - 1973.

6. Arps, J.J. and T.G. Roberts, "Economics of Drilling for Cretaceous Oil Production on the East Flank of Denver-Julesburg Basins". American Association of Petroleum Geologists Bulletin, Vol. 42, No. 11 (November 1958).

7. Averch, H. and L.L. Johnson, "Behavior of the Firm Under Regulatory Constraint". The American Economic Review, Vol. 52, No. 5 (December 1962).

8. Balestra, P., The Demand for Natural Gas in the United States. Amsterdam: North Holland Publishing Company, 1967.

9. __________ and M. Nerlove, "The Demand for Natural Gas". Econometrica, Vol. 34, No. 3 (July 1966).

10. __________, "Pooling Cross-Section and Time Series Data in the Estimation of a Dynamic Model: The Demand for Natural Gas". Econometrica, Vol. 34, No. 3 (July 1966).

11. Baumol, W.J. and A.K. Klevorick, "Input Choices and Rate of Return Regulation: An Overview of the Discussion", The Bell Journal of Economics and Management Science, Vol. 1, No. 2 (Autumn 1970).

12. Bradley, P.G., The Economics of Crude Petroleum Production. Amsterdam: North-Holland, 1968.

13. Breyer, S.G. and P.W. MacAvoy, Energy Regulation by the Federal Power Commission. Washington, D.C.: Brookings Institution, July 1974.

14. __________, "The Natural Gas Shortage and the Regulation of Natural Gas Producers". Harvard Law Review, Vol. 86, No. 6 (April 1973).

15. Brown, A. and A. Deaton, "Surveys in Applied Economics: Models of Consumer Behavior". The Economic Journal, Vol. 82, No. 4, (December 1972).

16. Challa, K., "Investment and Returns in Exploration and the Impact on the Supply of Oil and Natural Gas Reserves". Unpublished Ph.D. dissertation, M.I.T. Sloan School of Management, 1974.

17. Chetty, V.K., "Pooling of Time Series and Cross-Section Data". Econometrica, Vol. 36, No. 2 (April 1968).

18. Chow, G.C., "Technological Change and the Demand for Computers". The American Economic Review, Vol. 57, No. 5 (December 1967).

19. Council of Economic Advisors, Economic Indicators. Published monthly, 1960 - 1972.

20. Dam, K.W., "The Pricing of North Sea Gas in Britain". Journal of Law and Economics, Vol. 13, No. 1 (April 1970).

21. Diener, W.P., "Area Price Regulation in the Natural Gas Industry of Southern Louisiana". Tulane Law Review, Vol. 46 (1972).

22. Dirlam, J.B., "Natural Gas: Cost, Conservation, and Pricing". American Economic Review, Vol. 48, No. 2 (1958).

23. Douglas, P.H., "The Case for the Consumer of Natural Gas". Georgetown Law Journal, Vol. 44 (1955).

24. Edison Electric Institute, Statistical Annual of the Electric Utility Industry.

25. Eisner, M. and R.S. Pindyck, "A Generalized Approach to Estimation as Implemented in the TROLL/1 System". Annals of Economic and Social Measurement (January 1973).

26. Erickson, E.W. and R.M. Spann, "Supply Price in a Regulated Industry: The Case of Natural Gas". The Bell Journal of Economics and Management Science, Vol. 2, No. 1 (Spring 1971).

27. Fair, R.C., "The Estimation of Simultaneous Equation Models with Lagged Endogenous Variables and First Order Serially Correlated Errors". Econometrica, Vol. 38, No. 3 (May 1970).

28. Fisher, F.M., Supply and Costs in the U.S. Petroleum Industry: Two Econometric Studies. Baltimore: Johns Hopkins Press, 1974.

29. Garfield, P.J. and W.F. Lovejoy, Public Utility Economics. Englewood, N.J.: Prentice-Hall, 1964.

30. Garland, T.M. and W.D. Dietzman, "Engineering Cost Study of Development Wells and Profitability Analysis of Crude Oil Production". U.S. Bureau of Mines Information Circular #8561, 1972.

31. Gerwig, R.W., "Natural Gas Production: A Study of Costs of Regulation". Journal of Law and Economics, Vol. 5, No. 2 (October 1962).

32. Grilliches, Z., "A Note of Serial Correlation Bias in Estimates of Distributed Lags". Econometrica, Vol. 39, No. 1 (January 1971).

33. Hawkins, C.A., The Field Price Regulation of Natural Gas. Tallahassee: Florida University Press (1969).

34. Hildreth, G. and J.Y. Lu, "Demand Relations with Autocorrelated Disturbances". Technical Bulletin 76, Michigan State University Agricultural Experiment Station (November 1960).

35. Hoch, I., "Estimation of Production Function Parameters Combining Time-Serids and Cross-Section Data". Econometrica, Vol. 30, No. 1 (January 1962).

36. Houthakker, H.S. and L.C. Taylor, Consumer Demand in the United States 1929 - 1970. Cambridge: Harvard University Press, 1966.

37. Kahn, A.E., "Economic Issues in Regulating the Field Price of Natural Gas". American Economic Review, Vol. 50, No. 2 (1960).

38. __________, The Economics of Regulation. New York: John Wiley & Sons, Inc., 1970.

39. Kaufman, G.M., "Sampling Without Replacement and Proportional to Random Size". Memorandum II to the M.I.T. Natural Gas Research Group, March 19, 1973.

40. __________, Statistical Decision Theory and Related Techniques of Oil and Gas Exploration. Englewood Cliffs, N.J.: Prentice Hall (1963).

41. __________, Y. Baker and D. Kruyt, "A Probabilistic Model of the Oil and Gas Discovery Process -- Part I". Unpublished memorandum, Sloan School of Management, M.I.T., March 1974.

42. Khazzoom, J.D., "The F.P.C. Staff's Econometric Model of Natural Gas Supply in the United States". The Bell Journal of Economics and Management Science, Vol. 2, No. 1 (Spring 1971).

43. __________, "Gas Directionality". Public Utilities Fortnightly, Vol. 84 (December 18, 1969).

44. Kitch, E.W., "Regulation of the Field Market for Natural Gas by the Federal Power Commission". Journal of Law and Economics, Vol. 11, No. 2 (October 1968).

45. Kmenta, J., Elements of Econometrics. New York: Macmillan, 1971.

46. Kuh, E., "The Validity of Cross-Sectionally Estimated Behavior Equations in Time Series Applications". Econometrica, Vol. 30, No. 1 (January 1962).

47. ________ and J.R. Meyer, "How Extraneous are Extraneous Estimates?" Review of Economics and Statistics, Vol. 39, No. 4 (November 1957).

48. Landis, J.M., Report on Regulatory Agencies to the President-Elect, December 1960.

49. Leland, H.E., "The Theory of the Firm Facing Uncertain Demand". Report No. 24, Stanford Institute for Mathematics, 1970.

50. Lintner, J., "The Valuation of Risky Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets". Review of Economics and Statistics, Vol. 46, No. 1 (February 1964).

51. MacAvoy, P.W., The Crisis of the Regulatory Commissions. New York: Norton, 1970.

52. ________, "The Effectiveness of the Federal Power Commission". The Bell Journal of Economics and Management Science, Vol. 1, No. 2 (Autumn 1970).

53. ________, "The Formal Work-Product of the Federal Power Commissioners". The Bell Journal of Economics and Management Science, Vol. 2, No. 1 (Spring 1971).

54. ________, Price Formation in Natural Gas Fields. New Haven: Yale University Press, 1962.

55. ________, "The Regulation-Induced Shortage of Natural Gas". Journal of Law and Economics, Vol. 14, No. 1 (April 1971).

56. ________ and R. Noll, "Relative Prices on Regulated Transactions of the Natural Gas Pipelines". Bell Journal, Vol. 4, No. 1 (Spring 1973).

57. ________ and R.S. Pindyck, "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage". The Bell Journal of Economics and Management Science, Vol. 4, No. 2 (Autumn 1973).

58. McCall, J.J., "Probabilistic Microeconomics". The Bell Journal of Economics and Management Science, Vol. 2, No. 2 (Autumn 1971).

59. McFadden, D., "Conditional Logic Analysis of Qualitative Choice Behavior". Economics Working Paper No. 199, University of California, Berkeley, November 1972.

60. McKie, J.W., "Market Structure and Uncertainty in Oil and Gas Exploration". Quarterly Journal of Economics, Vol. 74, No. 1 (February 1960).

61. Mills, E.S., "Uncertainty and Price Theory". Quarterly Journal of Economics, Vol. 73, No. 1 (February 1959).

62. Mossin, J., "Equilibrium in a Capital Asset Market". Econometrica, Vol. 34, No. 4 (October 1966).

63. National Journal Reports, "Congress Near Showdown on Proposal to Decontrol Gas Prices". May 25, 1974.

64. National Petroleum Council, U.S. Energy Outlook (Interim Report), Washington, D.C., 1971.

65. __________, U.S. Energy Outlook. Washington, D.C., December 1972.

66. New York Times, "Federal Power Commission Head Urges End to Gas Curbs". Aptil 11, 1973.

67. Oi, W.Y., "A Disneyland Dilemna: Two Part Tariffs". Quarterly Journal of Economics, Vol. 85, No. 1 (February 1971).

68. Park, R.E., "Prospects for Cable in the 100 Largest Television Markets". The Bell Journal of Economics and Management Science, Vol. 3, No. 1 (Spring 1972).

69. Philps, L., "A Dynamic Version of the Linear Expenditure Model". Review of Economics and Statistics, Vol. 54, No. 4 (November 1972).

70. __________, "Substitution, Complementarity, and the Residual Variability Around Dynamic Demand Functions". American Economic Review (September 1971).

71. Pindyck, R.S., "The Regulatory Implications of Three Alternative Econometric Supply Models of Natural Gas". The Bell Journal of Economics and Management Science, Vol. 5, No. 2 (Autumn 1974).

72. Pirson, S., Oil Reservoir Engineering. New York: McGraw-Hill, 1958.

73. Pollak, R.A., "Habit Formation and Dynamic Demand Functions". Journal of Political Economy, Vol. 78 (1970).

74. __________ and P.J. Wales, "Estimation of the Linear Expenditure System". Econometrica, Vol. 37, No. 4 (October 1969).

75. Posner, A., "Taxation by Regulation". The Bell Journal of Economics and Management Science, Vol. 2, No. 1 (Spring 1971).

76. Potential Gas Agency, Colorado School of Mines, Potential Supply of Natural Gas in the U.S. Potential Gas Association, Minerals Resources Institute, Colorado University, 1971.

77. Pressman, I., "A Mathematical Formulation of the Peak-Load Pricing Problem". The Bell Journal of Economics and Management Science, Vol. 1, No. 2 (Autumn 1970).

78. Rowe, J.L., "Price Boost Approved for Natural Gas". The Washington Post, June 26, 1974.

79. Ryan, J.M., "National Academy of Sciences Report on Energy Resources: Discussion of Limitations of Logistic Projections". Bulletin of the American Association of Petroleum Geologists, Vol. 49, No. 10 (October 1965).

80. Sharpe, W.F., "Capital Asset Prices: A Theory of Market Equilibrium Under Conditions of Risk". Journal of Economics (September 1964).

81. __________, Portfolio Theory and Capital Markets. New York: McGraw-Hill, 1970.

82. Spritzer, "Changing Elements in the Natural Gas Picture: Implications for the Regulatory Scheme" in Brown, K.C. (ed.), Regulation of the Natural Gas Producing Industry. Baltimore: John Hopkins University Press, 1972.

83. Sussman, P.N., "Supply and Production of Offshore Gas Under Alternative Leasing Policies". Unpublished Master's thesis, Sloan School of Management, M.I.T., June 1974.

84. Taylor, L.D. and D. Weiserbs, "On the Estimation of Dynamic Demand Functions". Review of Economics and Statistics, Vol. 54, No. 4 (November 1972).

85. Uhler, R.S. and P.G. Bradley, "A Stochastic Model for Determining the Economic Prospects of Petroleum Exploration Over Large Regions". Journal of the American Statistical Association (June 1970).

86. U.S. Bureau of Mines, Annual Reports on Gas Consumption.

87. __________, Minerals Yearbook. Published annually.

88. U.S. Department of Commerce, Bureau of the Census, Annual Survey of Manufactures (1972).

89. U.S. Department of the Interior, Geological Survey -- Conservation Division, Outer Continental Shelf Statistics. Washington, D.C., June 1973.

90. U.S. Federal Power Commission, Annual Report for 1964. Washington, D.C.: U.S. Government Printing Office, 1965.

91. __________, Annual Report for 1972. Washington, D.C.: U.S. Government Printing Office, 1973.

92. __________, "Hugeton-Anadarko Area Rate Proceeding". Annual Report of the Federal Power Commission, 44 FPC 761, 1971.

93. __________, "Initial Rates for Future Gas Sales from All Areas". Annual Report for 1971, Washington, D.C.: U.S. Government Printing Office, 1972.

94. __________, "Southern Louisiana Area Rate Proceeding". Annual Report of the Federal Power Commission, 46 FPC 86, 1971.

95. __________, Proceedings on Curtailment of Gas Deliveries of Interstate Pipelines. Washington, D.C.: U.S. Government Printing Office, 1972.

96. __________, Sales of Natural Gas. Washington, D.C.: U.S. Government Printing Office, 1972.

97. __________, A Staff Report on National Gas Supply and Demand. Washington, D.C.: U.S. Government Printing Office, 1969.

98. __________, Statistics of Natural Gas Pipeline Companies, 1952 - 1967. Washington, D.C.: U.S. Government Printing Office.

99. __________, (Bureau of Natural Gas), The Gas Supplies of Interstate Natural Gas Pipeline Companies. Washington, D.C.: U.S. Government Printing Office, 1970.

100. __________, Natural Gas Supply and Demand, 1971 - 1990. Washington, D.C.: U.S. Government Printing Office, 1972.

101. U.S. Senate Commerce Committee, Hearings on Gas and Oil Regulatory Bills, 1973-1974.

102. __________, "Proposed Amendments to the Natural Gas Act". Staff Memorandum to the Chief Counsel, April 24, 1973.

103. U.S. Senate Committee on the Judiciary, Subcommittee on Administrative Practice and Procedure, Second Session Report on the Regulatory Agencies to the President-Elect (Landis Report), Committee Print, 1960.

104. Uren, L., Petroleum Production Engineering, 1934.

105. Vickrey, W.S., Microstatics. New York: Harcourt, Brace & World, Inc., 1964.

106. Wallace, T.D. and A. Hussain, "The Use of Error Components in Models Combining Cross-Section with Time Series Data". Econometrica, Vol. 37, No. 1 (January 1969).

107. Wellisz, S.H., "Regulation of Natural Gas Pipeline Companies: An Economic Analysis". Journal of Political Economy, Vol. 71, No. 1 (February 1963).

108. Westfield, F.M., "Methodology of Evaluating Economic Regulation". The American Economic Review, Vol. 61, No. 2 (May 1971).

109. Winch, D.M., "Consumers' Surplus and the Compensation Principle". The American Economic Review, Vol. 55, No. 4 (September 1965).

110. Zellner, A., "An Efficient Method of Estimating Seemingly Unrelated Regressions". Journal of the American Statistical Association, Vol. 57 (1962).