EFFICIENT CONTRACTING AND MARKET POWER: EVIDENCE FROM THE U.S. NATURAL GAS INDUSTRY*

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I. INTRODUCTION

THE transactions-cost approach to industrial organization[1] departs sharply from neoclassical tradition in its shift of emphasis from the market to the individual transaction. Behavior such as vertical integration and long-term contracting that had previously been viewed with suspicion as anticompetitive was explained as an efficient response to small-numbers bargaining problems. When a transaction entails one party committing capital that has little value in other uses, the other party has a strong incentive to appropriate the quasi rents through opportunistic actions.

A small literature has developed that explains various forms of organization that depart from repeated auction-market transactions between individual buyers and sellers as efficient responses to this "hold-up" problem rather than as monopolistic behavior.[2] The two are hardly mutu-

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[1] See, for example, Ronald H. Coase, The Nature of the Firm, 4 Economica 386 (n.s. 1937); and Oliver E. Williamson, Markets and Hierarchies (1975).

[2] See, for example, Vertical Integration in the Oil Industry (Edward J. Mitchell ed. 1976).

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ally exclusive, however, but attempts to disentangle them are difficult. The role of contractual arrangements—while important in many markets for commodities and industrial products—has not received much attention in empirical work.

Two fundamental problems must be overcome in order to distinguish the new approach from market power as a motivation for observed long-term linkages between buyers and sellers. First, the transactions-cost hypothesis is not easily falsifiable because it is not associated with a particular formal model. Second, although the approach suggests some testable hypotheses, the necessary data on individual transactions are almost never publicly available. Empirical work has required laborious surveys or extraction of provisions from individual contracts.[3]

This article takes advantage of a large, detailed data set on contracts between U.S. natural gas producers and pipelines signed during the 1950s. Many factors may motivate long-term contracting.[4] Considerations of transactions costs and the potential for opportunism in the bilateral relationship are probably most important in explaining the use of long-term contracts between producers and pipelines. When a market is characterized by small-numbers bargaining, trade organized through spot exchange is prone to frequent and costly renegotiation.[5] In the natural gas industry, the wellhead producer and pipeline face this problem. (We discuss contracting procedure in more detail later.) In addition, once the initial gas well development costs are sunk, a pipeline faces the tempta-

[3] See, for example, Victor P. Goldberg & John E. Erickson, Quantity and Price Adjustment in Long-Term Contracts: A Case Study of Petroleum Coke, 30 J. Law & Econ. 369 (1987); Kirk Monteverde & David J. Teece, Supplier Switching Costs and Vertical Integration in the Automobile Industry, 13 Bell J. Econ. 206 (1982); Gary D. Libecap & Steven N. Wiggins, Contractual Responses to the Common Pool: Prorationing of Crude Oil Production, 74 Am. Econ. Rev. 87 (1984); Paul L. Joskow, Vertical Intergration and Long-Term Contracts: The Cast of Coal-burning Electric Generating Plants, 1 J. L. Econ. & Org. 33 (1985); Paul L. Joskow, Contract Duration and Relationship-specific Investments: Empirical Evidence from Coal Markets, 77 Am. Econ. Rev. 168 (1987); Steven N. Wiggins & Gary D. Libecap, Oil Field Unitization: Contractual Failure in the Presence of Imperfect Information, 75 Am. Econ. Rev. 368 (1985); Scott E. Masten & Keith J. Crocker, Efficient Adaptation in Long-Term Contracts: Take-or-Pay Provisions for Natural Gas, 75 Am. Econ. Rev. 1083 (1985); and R. Glenn Hubbard & Robert J. Weiner, Regulation and Long-Term Contracting in U.S. Natural Gas Markets, 35 J. Ind. Econ. 71 (1986).

[4] See, for example, arguments relating to risk allocation when buyers and/or sellers are risk averse—as in Dennis W. Carlton, Contracts, Price Rigidity, and Market Equilibrium, 87 J. Pol. Econ. 1034 (1979); R. Glenn Hubbard & Robert J. Weiner, Long-Term Contracting and Multiple-Price Systems, J. Bus. (in press); and A. Mitchell Polinsky, Fixed Price versus Spot Price Contracts: A Study in Risk Allocation, 3 J. L. Econ. & Org. 27 (1987).

[5] See Williamson, *supra* note 1; and Oliver D. Hart & Bengt Holmstrom, The Theory of Contracts (Working Paper No. 418, Massachusetts Inst. Technology, Dep't Economics 1986).

tion to appropriate some of the rents from production unless the producer has an alternative means of sale.[6] The pipeline itself is a form of specific capital. Since it is best operated near full capacity, a long-term contract "guaranteeing supplies" is in the buyer's interest as well.

The natural gas industry provides an ideal laboratory for examination of both transaction-cost and market-power models because of the relatively small number of buyers and sellers in each market and because of the specific upfront capital investments required on the part of both sellers, in the form of natural gas wells, and buyers, in the form of pipeline connections. Pricing in field markets is the outcome of bilateral negotiations; there is no organized marketplace, nor any market price.

Instead, the buyer (pipeline company) and seller (producer) negotiate a long-term contract that specifies the initial price to be paid for gas delivery, the quantity to be delivered, and the escalator provisions that determine the amount paid over the life of the contract. The initial price, referred to hereafter simply as "the price," provides a floor on the value of the contract to the producer. Although prices were rigid downward, they could rise through the presence in some contracts of definite price escalators (increases of a fixed amount per year) and indefinite price escalators (increases depending on market conditions). In addition, redetermination clauses permitted renegotiation of the terms of the contract at predetermined intervals.

Below, we present a model of the bilateral bargaining process in natural gas field markets under uncertainty. This model enables us to identify the price as the outcome of the bargaining over a fixed payment from pipeline to producer, and observed price-escalator provisions as a means of making the contract responsive at the margin to changes in the valuation of gas over the term of the agreement. These changes are uncertain because future movements in marginal cost and downstream demand are not known when a contract is signed.

The objective of our empirical work is to consider the relative effects of transaction-specific and market-power considerations on outcomes of contract negotiations. As noted above, the hypothesis that long-term contracting is a means of approximating efficiency in an environment of small-numbers bargaining, uncertainty, and immobile capital is difficult to reject because the transactions-cost model is often quite general and not formalized. We therefore focus on the central element of the theory—the emphasis on conditions characterizing the transacting parties

[6] This is as in Benjamin Klein, Robert Crawford, & Armen Alchian, Vertical Integration, Appropriable Rents, and the Competitive Contracting Process, 21 J. Law & Econ. 297 (1978).

and the transaction itself, rather than the market—as the determinant of observed prices and contract terms.

Our empirical work consequently entails testing for the effects of transaction-specific and market-specific factors on the outcomes of contract negotiations. Clearly, for price determination alone, the two hypotheses are not mutually exclusive.

The contract terms we seek to predict on the basis of transaction- and market-specific information are, however, both price and the presence of an indefinite price escalator in the contract. Although several indefinite escalators are in use in gas contracts today (for example, indexation to petroleum prices and the price level), the chief indefinite escalator during the period of our data was the most-favored-nation (MFN) provision. An MFN clause in a contract raises the contract price to the level of the price agreed to by the pipeline in any contracts signed later in nearby areas.[7] In addition to its wide use, the MFN provision is particularly appropriate for distinguishing between market-power and transaction-cost theories of contracting. Under the latter, an MFN clause can mitigate the ex post opportunistic behavior; sellers fearful of being at a disadvantage in contract negotiations can protect themselves by providing that future bargaining outcomes will apply to them as well. This feature is important. Joskow in particular has emphasized the potential relationship between the degree of asset specificity in a transaction and the length of the contract between the buyer and seller.[8] That relationship raises the question of how price is modified over the course of the contract as demand and cost conditions change.[9]

As described below, these two hypotheses yield different predictions regarding the occurrence of MFN clauses. We are thus able to test the extent to which MFN provisions serve an efficiency role, or whether they are part of monopolistic or monopsonistic arrangements. Although our tests are conducted on data from natural gas field markets, we believe the results shed light on small-numbers-bargaining and contracting problems in any product markets.

Our principal empirical findings are two. First, we find some evidence of monopsony potential in determining initial contract prices, though buyer and seller size (both absolutely and within particular markets) are also important. Second, we find that use of the MFN clause does not

[7] An MFN clause could serve only to raise prices, not to lower them. During the period covered by our data, however, prices increased steadily.

[8] See Joskow, Contract Duration, *supra* note 3.

[9] See Paul L. Joskow, Price Adjustment in Long-Term Contracts: The Case of Coal, 31 J. Law & Econ. 47 (1988).

reflect producer market power, nor does the clause have a unique shadow price in producer-pipeline contracts. The provisions are most often used by small producers (those with few contracts) to ensure flexible marginal compensation in periods of growing demand. These findings are common to reduced-form price and MFN equations and to a joint estimation.

The article is organized as follows. We develop a simple model of producer-pipeline contracting in Section II*A*. Section II*B* relates the key features of the model to the observed contracting process in the gas market. A detailed review of natural gas field markets in the 1950s (the period we examine) and of available data is presented in Section III. Empirical tests of models of price determination and the use of MFN clauses are presented in Sections IV and V, respectively. In Section VI, we present additional evidence from an endogenous switching regression model, in which the effect of transaction-specific variables on contract prices is allowed to vary according to whether the contract contains an MFN clause. Some conclusions and implications are discussed in Section VII.

II. Contracting in the Natural Gas Market

A. *Long-Term Contracting as a Bargaining Problem*

Tests of models of contractual provisions designed to mimic efficiency in the presence of market imperfections have been conducted by labor economists,[10] but applications to product markets have been rare. Public policy discussions of the structure of natural gas contracts and social desirability of wellhead price regulation require an analysis of whether contracts are designed to facilitate the exercising of market power by one or both parties or to approximate auction-market efficiency in the presence of transactions costs. Unlike other natural resource markets (for example, the oil market), which tend to be characterized by both spot and contract trades, gas sales have occurred overwhelmingly under long-term contracts. Other commodity markets lack the fundamentally bilateral re-

[10] Theoretical analyses of bilateral-monopoly bargaining date to early neoclassical writers. Our approach parallels closely models of bilateral bargaining between firms and labor unions that emphasize contracts for wages and employment. Such bargaining problems stem from the importance of specific capital and asymmetric information, both of which figure prominently in the natural gas market. It is well known in the labor economics literature that optimal contracting in the presence of asymmetric information will involve a specified relationship between employment and wage. See, for example, Robert E. Hall & David M. Lilien, Efficient Wage Bargains under Uncertain Supply and Demand, 69 Am. Econ. Rev. 868 (1979); and the survey in Oliver D. Hart, Optimal Labor Contracts under Asymmetric Information: An Introduction, 50 Rev. Econ. Stud. 3 (1983).

lationship at the producer level since buyers and sellers are not linked by immobile capital.

Our basic framework draws on the implicit contracting models.[11] Pipeline technology, rolled-in pricing,[12] and final demand for natural gas are summarized in a revenue function $R(Q)$, which gives dollar net revenue to the pipeline (sales less operating costs) as a function of the intake Q of gas from the wellhead. Let $C(Q)$ represent the wellhead producer's opportunity cost of producing Q. In the absence of market imperfections, marginal efficiency would be assured, and $R'(Q) = C'(Q)$.

In natural gas field markets, however, the cost of locating alternative suppliers or purchasers is often prohibitive. The contracts that arise from the resulting bilateral bargaining problem serve at least in part to distribute rents between the pipeline and the producer. The contract specifies a payment $B(Q)$ from pipeline to producer as a function of output in each period of the contract.

There is, of course, substantial uncertainty over circumstances prevailing over the duration of the contract. Such uncertainty arises from demand shocks—because of fluctuations in economic activity or exogenous changes in the prices of alternative fuels—and supply shocks—changes in opportunity costs of production. Demand shocks are captured in a random variable, α, so that the revenue function becomes $R(Q, \alpha)$. On the supply side, shocks are characterized by a random variable, β, so that the cost function is $C(Q, \beta)$.

Both pipelines and producers are assumed to be risk neutral,[13] maximizing expected profits, given by

$$\pi_p = R(Q, \alpha) - B(Q, \alpha, \beta), \tag{1}$$

and

$$\pi_w = B(Q, \alpha, \beta) - C(Q, \beta), \tag{2}$$

respectively.

Given realizations of α and β, the efficient level of output $Q^*(\alpha, \beta)$ still requires equality of the value of the marginal product of gas as a pipeline

[11] See Hall & Lilien, *supra* note 10.

[12] "Rolled-in pricing" is the industry term used to refer to downstream regulation, which is essentially based on rates of return. Gas purchased by a pipeline at various prices is rolled in to come up with an average acquisition cost.

[13] Adding risk aversion does not change qualitatively the results presented in Section II; see Jerry Green & Charles M. Kahn, Wage-Employment Contracts, 98 Q. J. Econ. 173 (Suppl. 1983).

input and the marginal opportunity cost of wellhead production, so that

$$\frac{\partial R(Q, \alpha)}{\partial Q} = \frac{\partial C(Q, \beta)}{\partial Q}. \tag{3}$$

Equation (3) implicitly defines the set of ex post efficient payment rules $B[\alpha, \beta, Q^*(\alpha, \beta)]$. Problems arise because the rules themselves can depend on the outcomes of the supply and demand shocks. Not all variables affecting the contract may be anticipated by the transacting parties.

The distribution of rents, a significant component of the bargaining problem, is not specified by the efficiency conditions. The shape of the payment function B is determined by efficiency conditions; however, the level of payment is not without further assumptions. In general, ideal contracts conditioned only on output (to avoid the monitoring problems discussed above) do not exist because the payment function is "lacking in instruments" to target efficiency under all potential realizations of α and β.

Absent problems of opportunism, an efficient output-contingent contract exists in the special case where demand and opportunity-cost shocks are related by a monotonic function; that is, $\beta = f(\alpha)$. This case stylizes the natural gas industry because of the exhaustible nature of the resource. Stochastic demand shifts affect the price of gas in the future, thereby affecting opportunity cost today. In this case, an efficient contract satisfies the conditions

$$\frac{\partial R(Q, \alpha)}{\partial Q} = B'(Q), \tag{4}$$

and

$$\frac{\partial C[Q, f(\alpha)]}{\partial Q} = B'(Q). \tag{5}$$

Let $\alpha(Q)$ represent the value of the demand shock for which Q is the efficient output level (that is, the inverse function of $Q^*(\alpha)$). Then, integrating the differential equation (5) over Q yields a payment rule of the form

$$B(Q) = \overline{B} + \int_0^Q \frac{\partial C\{Q, f[\alpha(Q)]\}}{\partial Q} dQ, \tag{6}$$

where $\overline{B}$ is independent of output and determined through contract negotiation. That is, the lump-sum compensation $\overline{B}$ encompasses inframarginal payments. We discuss below the implementation of the contractual bargain in the natural gas field markets.

B. Implementing the Efficient Contract

The model outlined above yields the result that the efficient contract under demand uncertainty and bilateral monopoly is characterized by a fixed payment that is unrelated to variable cost conditions and a flexible payment that covers marginal opportunity costs. Contracts of this form will involve a fixed payment as a quasi rent, the distribution of which demands on the relative bargaining position of the contracting parties. The flexible payment ensures appropriate compensation on the margin.

There are two aspects of timing in contractual arrangements between buyers and sellers in these markets. First, with respect to the period in which a contract is signed, the producer's time frame encompasses the interval during which offers from pipelines can be entertained. Wellhead producers typically do not consider offers until exploratory drilling has been conducted to the point where a reliable estimate of sustainable volume can be obtained. MacAvoy notes that there was typically a two-year maximum time interval between exploratory drilling and lapse of the lease on the property. The relevant time frame for a pipeline is longer. As discussed by MacAvoy: "A new pipeline usually obtains the reserves necessary for certification within one to four years (while engineering and financing of transmission are planned). Once the original reserves are obtained, there is no urgent need for a transporter to purchase replacement reserves until twenty years have passed. Actually, it may be least costly for the buyer to purchase reserves equal to five years' production every five years. . . . The buyer's market includes most reserves offered in a five-year period in the established gathering region."[14]

The second aspect of timing in the contractual arrangement is that once the large capital outlays are made they are sunk for the duration of the contract (typically twenty years). Given the difference in initial market time frame for the buyer and seller, the possibility for opportunistic behavior on the part of the pipeline is clear. There is little reason to believe that, absent contractual provisions to the point, pipelines would compensate producers for changes in the value of their gas as demand increased over time.

Hence, given the particular conditions governing producer-pipeline bargains, the efficient contract cannot be implemented without the use of provisions to guard against the possibility of opportunistic behavior after the contract is signed. Natural gas is sold by the producer to a pipeline, which then transports it to distribution companies or final users downstream; producers lacked direct access to downstream markets until re-

[14] Paul W. MacAvoy, Price Formation in the Natural Gas Fields, 53–56 (1962).

cently (that is, the late 1980s). More than a simple price guarantee is required to support $\overline{B}$ in equation (6) since a pipeline could force renegotiation at a lower price. If the producer objected, the pipeline could reduce purchases. Since pipelines in general have significant alternative sources of supply, such a threat would be credible.

In field markets for natural gas, the fixed payment is determined as follows. Contracts typically specify a minimum payment each year, regardless of downstream demand, in terms of a take-or-pay requirement, calculated as the product of a fixed contract price and a fixed quantity specified as a percentage of the well's physical production capacity.[15] Definite (fixed-price) escalators establish minimum prices in each period of the contract. These provisions, together with the price and the take-or-pay provision, guarantee a minimum payment to the producers in each period of the contract. Take-or-pay percentages varied little across contracts in quantity terms,[16] though the price set in the contract in general differs across contracts depending on differences in costs and on the relative bargaining positions of the transacting parties. We address this issue in the next section.

In his pioneering work, MacAvoy considered static comparisons of models of pipelines monopsony and competition in explaining price determination in natural gas fields. Within the framework of our model, it is possible that differences in horizontal market power on the buyers' and sellers' sides affected the distribution of the rents in natural gas production. It is important to remember, however, that the middle and late 1950s were a time of new discoveries in the fields and of expanding final demand for natural gas. Most pipelines signed large numbers of contracts with many producers. The number of pipelines dealt with by a single producer in different fields or markets obviously varied with the size of the producer. For producers with many contracts, producer-pipeline relationships were an ongoing process of signing new contracts, suggesting that

[15] An alternative to long-term contracting in these circumstances is that the transaction-specific assets be jointly owned, through vertical integration or a joint venture between buyer and seller. The issue of joint ownership versus long-term contracting does not arise here because downstream cost-of-service regulations discouraged pipeline companies from owning natural gas wells. In the Hope Natural Gas case (320 U.S. 603 (1944)), the U.S. Supreme Court upheld the Federal Power Commission (FPC, the regulatory body in this industry—regulation is described in detail below) practice of computing cost of service for regulated utilities on an original cost rather than replacement cost basis. Thus, integrated producer-pipeline companies could not take advantage of rising wellhead prices. The fraction of U.S. natural gas produced by pipeline companies dropped from 36 percent at the time of the Supreme Court decision to 13 percent ten years later. See Arlon R. Tussing & Connie C. Barlow, The National Gas Industry (1984).

[16] See MacAvoy, *supra* note 14.

a static market-power approach to analyzing price determination, while useful for some issues, will likely be inadequate for modeling contracts in a market with repeated trades.

Efficiency in contracting outcomes requires that prices paid over time reflect changing demand conditions (valuation of the gas). Given the vertical structure of the market, with the importance of large sunk-cost capital investments and the potential for opportunistic behavior, there is no reason to believe that pipelines will represent downstream demand correctly in providing marginal compensation to producers. Nothing would guarantee increases in real prices in response to growth in demand.

One clause providing some protection against this type of opportunistic behavior is the two-party MFN clause, commonly used in contracts during this period. Simply put, the clause states that, if a pipeline signs a new contract in a field at a higher price than that paid on existing contracts in that field, it must grant the higher price to existing contracts as well. It is important to note that adjustment occurs only in one direction; the initial price acts as a floor over the life of the contract. When combined with the take-or-pay requirement, the initial price serves to guarantee the payment $\overline{B}$, irrespective of demand fluctuations.

As an alternative to complex contracts contingent on the realization of cost and demand disturbances, contracts with a two-party MFN clause allow the pipeline to vary transaction prices and quantities, while stopping it from discriminating against "old" and "new" sellers (as in the spirit of the commitment problem discussed by Coase).[17] During a time of rapid growth in which large numbers of contracts are signed each period, MFN clauses are useful since transaction prices in a contract are linked to terms in future contracts, rather than to movements in underlying costs or demand, which are unlikely to be observable by both parties to the contract.[18] For such a provision to be useful in practice, however, sellers should be relatively homogeneous—having similar underlying cost structures and selling to the same downstream market. Natural gas field markets in the 1950s fit this description well.

Large producers are more likely to operate in several field markets than small producers and are less likely to be at an informational disadvantage relative to pipelines. When downstream demand is not directly observable, the two-party MFN may be a useful proxy. Prices are adjusted to reflect not only the field market valuation of gas but also its resale value. Signing of new contracts occurs only when downstream demand condi-

[17] Ronald H. Coase, Durability and Monopoly, 15 J. Law & Econ. 143 (1972).

[18] Note that, since clauses link prices to the outcomes of future contract negotiations, they are not merely a means of creating a spot market under another name.

tions warrant payment of prevailing field prices. In addition, when the pipeline has superior information about current and future levels of downstream demand, the MFN provision can have substantial value. By putting the clause in the contract, a seller can mitigate the problem of being outnegotiated for a lack of knowledge about current or future demand and prices. This information would be most needed by small producers, who lack the resources to prepare elaborate forecasts of downstream demand.[19]

Our interpretation of the MFN as an instrument to replicate efficient contracting during periods of growing demand implies that it is unlikely to be merely a reflection of producer market power, a claim often made by proponents of wellhead price controls in the 1950s. Even at first glance, the market-power argument is not very convincing. If producer market power were important, there is no reason that it should have materialized in the form of MFNs rather than high initial prices or take-or-pay requirements. In addition, the MFN is activated at the discretion of the buyer. It is also inappropriate to think of the MFN as just a means of nonprice competition. Studies of regulated industries have emphasized the importance of nonprice competition,[20] but wellhead price ceilings were not binding during our period of study. In a highly competitive, growing market, relatively high prices and frequent use of MFNs, might go hand in hand. A mature market with substantial monopsony power might be characterized by both low prices and a general absence of MFN provisions.[21]

III. U.S. Natural Gas Field Markets: Background, Data, and Existing Literature

A. *Historical Setting and Data*

The industry developed in the 1930s with the discovery of large fields in the Southwest and the introduction of seamless pipe, which allowed the construction of large pipelines to transport gas at high pressure without leakage over the long distances from producing areas to consumers in the East, Midwest, and West. The Natural Gas Act of 1938 authorized the Federal Power Commission (FPC) to regulate interstate pipeline tar-

[19] Recall that there are no auction-market prices to which the individual seller can refer.

[20] See, for example, Hubbard & Weiner, *supra* note 3.

[21] We describe as "mature" markets wherein geological uncertainty is relatively small due to extensive drilling. During the 1950s, the eastern Gulf coast, Hugoton/Panhandle, and West Texas/New Mexico markets fit this description most closely.

iffs, but wellhead prices (the prices charged by producers to pipelines) remained uncontrolled.[22]

The Supreme Court extended the FPC's jurisdiction to wellhead prices in the *Phillips* case in 1954.[23] The decision was based in large part on the alleged monopoly power of Phillips Petroleum, the largest of the more than 2,000 independent[24] producers selling natural gas into interstate commerce in the late 1940s and other large gas producers. Natural gas demand had risen sharply after World War II, and Phillips and other producers had raised prices substantially. Alleged monopoly power by gas producers was a major policy issue throughout the 1950s.[25]

As a result of the *Phillips* decision, the FPC froze wellhead prices in 1954 and required producers to file rate schedules[26] on their existing contracts, requests for price increases, and new contracts. In this era of increasing demand and prices there followed a deluge of price-increase requests and requests for new-contract certification, inundating the commission, which was obliged to approve the vast majority of them.[27] The commission estimated that, utilizing its time-consuming cost-based regulatory procedures, it would require until the year 2043 to review the thousands of requests it had received by 1960.[28]

The FPC abandoned its quixotic effort to base prices on costs at individual wells in 1960 and adopted pricing based on geographic areas. Prices were effectively unregulated until that time and had nearly doubled since 1954.

Our data base consists of 1,804 contracts filed between 1953 and August 1957. The contracts filed run to several pages each, but fortunately the relevant economic data were extracted and compiled systematically as part of the initial rate hearing (the so-called Omnibus Hearing on regula-

[22] Discussions of natural gas regulation can be found in Ronald R. Braeutigam & R. Glenn Hubbard, Natural Gas: The Regulatory Transition, in Regulatory Reform: What Actually Happened (Leonard Weiss & Michael Klass eds. 1986); and Richard H. K. Vietor, Energy Policy in America since 1945 (1984).

[23] Phillips Petroleum v. Wisconsin et al. 342 U.S. 672 (1954).

[24] "Independent" refers to gas not produced by a pipeline company.

[25] See Vietor, *supra* note 22.

[26] "Rate Schedule" refers to the provisions of the contract.

[27] The FPC declined to review initial prices on new contracts (see MacAvoy, *supra* note 14, at 253). It did review price increases. Of the roughly 2,400 applications it received in the year following *Phillips*, only about 100 were suspended for investigation. Most of these were later approved. See Martin L. Lindahl, Federal Regulation of Natural Gas Producers and Gatherers, 46 Am. Econ. Rev. Papers & Proc. 532 (1956).

[28] See Braeutigam & Hubbard, *supra* note 22.

tory methods) following the *Phillips* decision.[29] The data cover the majority of transactions during this period. Each contract is a transaction because regulators obliged producers to dedicate the output from each well to only one pipeline. Omitted are (1) contracts for gas not dedicated to interstate commerce (since intrastate pipelines were outside FPC jurisdiction);[30] (2) short-term contracts (with a duration of less then twenty years);[31] (3) wells outside the main producing areas of the Gulf Coast, Southwest, and Rocky Mountains (which account for over 90 percent of U.S. production); and (4) contracts signed but not yet filed by September 1, 1957.

Associated with each transaction is the following information: pipeline, producer, date, location (state, county, and gas field), term length, price adjustment clause, initial price, price on June 30, 1957 (only three contracts in the data base were filed after this date), and volume in 1956 (for contracts filed after July 1, 1956, the volume in the first month of the contract). Some transactions have missing data, and some judgments were necessary regarding the identities of producers (for example, individual producers who appeared to be from the same family were aggregated).

These data provide a rare opportunity to observe prices charged by each seller to each buyer. The difficulty, as usual in industrial organization, is to define markets in an economically meaningful manner. The Federal Power Commission classified the major producing areas into three regions—Gulf Coast, Midcontinent, and Rocky Mountains. The FPC then divided the Gulf Coast region into five markets, from east to west: Mississippi, Southern Louisiana, Houston, Goliad, and Corpus Christi. The Midcontinent region was likewise divided into five markets: North Louisiana/East Texas, Hugoton/Panhandle, North Texas/Oklahoma, Kansas, and West Texas/Southeast New Mexico. The markets are depicted in Figure 1.

[29] Champlin Oil and Refining Co. *et al.* (Federal Power Commission Docket G-9277, 1957–59), exhibit 4-LC.

[30] MacAvoy, *supra* note 14, estimates that 70–80 percent of gas in contracts signed during this period was sold in interstate commerce.

[31] Short-term contracts were less desirable to pipelines because they could not be counted toward their regulatory reserve requirements. The 165 short-term contracts reported during the 1953–57 period were collected separately in the *Champlin* docket, *supra* note 29, exhibit 50, schedule 8. Since all contracts were for the life of the well, contract length was based on geological factors, rather than the outcome of bargaining. The short-term contracts in the data base are concentrated in particular fields. The vast majority of our 1,804 long-term contracts were twenty years.

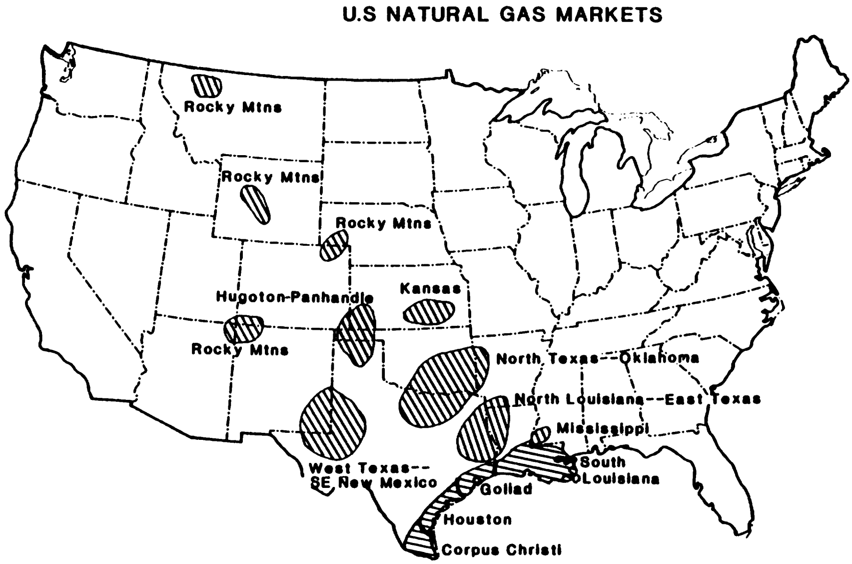

FIGURE 1.—U.S. natural gas markets

In his early study of price formation in natural gas fields, MacAvoy[32] reclassified the North Louisiana/East Texas (into the Gulf Coast region) and West Texas/Southwest New Mexico (into the Rocky Mountain region) markets on the basis of the destination of the gas produced there. Roughly speaking, Gulf Coast supplies went to the East, Midcontinent supplies to the Midwest, and Rocky Mountain supplies to the West. Market definition is discussed in detail by MacAvoy; with minor exceptions, we follow his classification (the Appendix provides a list of counties in each market).[33]

B. Previous Economic Research on Natural Gas Markets

Despite the intense political controversy, economic interest,[34] and data gathering and compilation at the time of wellhead price control, there

[32] See MacAvoy, *supra* note 14.

[33] Any market definitions are somewhat arbitrary, of course. To examine the robustness of the definitions we use, we also considered the following rules: (1) along the Gulf Coast, use the market definitions followed by the Federal Power Commission in *Champlin Oil, supra* note 29; (2) elsewhere, contracts in adjacent counties are included in the same market; (3) markets end where contracts are not contained in adjacent counties. Results obtained using these rules were very similar to those reported here.

[34] See Vietor, *supra* note 22; Lindahl, *supra* note 27; Alfred E. Kahn, Economic Issues in Regulating the Field Price of Natural Gas, 50 Am. Econ. Rev. Papers & Proc. 506 (1960); and Edward J. Neuner, The Natural Gas Industry (1960).

was little attempt at empirical analysis of market power. In the Omnibus Hearings, producers argued that the FPC should approve all prices that were the outcome of "competitive market forces" and intervene only where such forces were absent. Economists' views were couched in terms of concentration levels. The procompetitive position was that nationwide the industry was unconcentrated on both buyer and seller sides relative to averages of all industries, while the anticompetitive argument noted that the market was not national and that only new contracts, not total production, mattered because existing contracts bound buyers and sellers together for the long term.[35] Under this definition, markets could no longer be characterized as unconcentrated.

Two studies actually looked at pricing. MacAvoy conducted a detailed investigation of structure and conduct in various markets and carried out the only econometric analysis.[36] He ran price regressions on one market at a time (on the *Champlin*-docket data), looking at the extent to which cost factors affected the prices pipelines paid. He tested for monopsony versus competition (ignoring monopoly), assuming nearly vertical supply curves so that prices paid would vary between producers under competition but not monopsony (because under monopsony pipelines could extract the Ricardian rents). Controlling for various cost factors, he found evidence of monopsony in some of the markets with few pipelines. He did not take advantage of any firm-specific information. Neuner used descriptive summary statistics on a smaller set of contracts to look for evidence of monopoly power.[37] He did not find any.

Recently, the *Champlin* data have been used to look for evidence on the transaction-cost hypothesis by Mulherin, who sought to explain two nonprice contractual provisions—the delivery point for natural gas in the field, and pipelines' take-or-pay obligations—as well as price-adjustment provisions.[38] Mulherin obtained results consistent with the transactions-cost hypothesis but did not exploit any firm-specific or cost information, making it impossible to distinguish transaction-cost from market-power motiviations. Like other empirical work in this area, Mulherin's study offers no real alternative to the transaction-cost theory.[39]

The more recent era of natural gas wellhead price regulation has been

[35] See Kahn, *supra* note 34.

[36] See MacAvoy, *supra* note 14.

[37] See Neuner, *supra* note 34.

[38] J. Harold Mulherin, Complexity in Long-Term Contracts: An Analysis of Natural Gas Contractual Provisions, 2 J. L. Econ. & Org. 105 (1986).

[39] See Monteverde & Teece, *supra* note 3; and Joskow, Vertical Integration, *supra* note 3.

examined by Masten and Crocker and Hubbard and Weiner.[40] Because wellhead price ceilings were set by the federal government, these articles focused on nonprice contractual provisions and the effects of price regulation thereon.

C. Testing Transaction Cost and Market Power Hypotheses

We divide our empirical efforts into two parts: (1) individual reduced-form models of the determination of initial contract prices and the use of the most-favored-nation clause, and (2) a model of price determination in which the coefficients on market-specific and transaction-specific variables vary according to whether the contract contains a most-favored-nation clause. Simultaneous price estimation and MFN determination is designed to address the claim that the presence of the MFN clause is merely another item that producers request as part of their contractual package, possibly to be traded off for a higher initial price in the contract.

Our approach can be summarized as follows. We define variables associated with (1) market structure, (2) transaction and information costs, and (3) production costs and investigate their relative impact on contract provisions. We identify the first group of variables with market-power models and the second group with transactions-cost models. The third group of variables serves as a control. Thus, we are able to test whether contracting theories based on transactions costs, market structure, or both have explanatory power in this setting.

We expect zero coefficients on all of the market-structure variables in the empirical work presented below if only transactions-cost considerations matter. Likewise, if only market-power theories are relevant, the transactions-cost variables will have zero coefficients. Of course, the theories are not mutually exclusive; nonzero coefficients on both groups of variables would indicate this. It is only by including both groups of variables in the same empirical model that the transactions-cost and market-power views can be disentangled, which previous research has not attempted.

Market structure is of interest because allegations of producer monopoly power were instrumental in the decision to regulate wellhead prices, as noted above. There have also been claims that pipelines have appropriated some producer rents through their exercise of monopsony power. In a textbook case of monopsony power, a bargaining situation in which a single buyer faces a large number of independent sellers in arm's-length transactions would lead to a depressed field-market price. Producer-pipeline dealings are, however, characterized by repeated transactions

[40] See Masten & Crocker, *supra* note 3; and Hubbard & Weiner, *supra* note 3.

between parties, so that bargaining on price and nonprice provisions may mitigate inefficiencies on the margin associated with monopsonistic behavior.

Defining market boundaries for measuring buyer and seller concentration is difficult. While most pipelines were able to gather gas in any field within a basin (or FPC market) in which they operated, producers' markets are much more narrow. Because, by the middle 1950s, most pipelines within a large market could collect gas in all of the fields within the market, we define our measures of producer concentration with respect to the full markets. A high concentration measure for production in a given small field would mean little if pipelines were free to gather gas from neighboring fields in the same general market. Realized producer market power is unlikely given the asymmetries noted in the sizes of pipeline and producer markets. Table 1 shows buyer and seller concentration levels in each of the eleven field markets. It is clear that buyer (pipeline) concentration levels are considerably higher than seller concentration levels. In empirical tests, we use the four-firm concentration ratio ($C4$) for sellers and the two-firm concentration ratio ($C2$) for buyers (since $C4$ was so close to unity), as well as the Herfindahl index for both buyers and sellers.[41]

Problems of opportunistic behavior are potentially important in gas markets because of the way transactions are organized. There is no central marketplace and no quoted market price. Rather, each contract is the outcome of bilateral negotiations. The pipeline and the well are both forms of immobile capital, and buyer and sellers have little choice but to deal with each other over an extended period.

An important asymmetry exists between buyers and sellers. Most sellers are small firms or individuals and are likely to have only one well, perhaps a handful.[42] The buyers are natural gas pipelines, large companies with knowledge of downstream demand and a large number of contracts to guide them in negotiating terms. Moreover, sellers have little recourse if buyers act opportunistically; the seller's definition of "market" is very restrictive. In contrast, buyers' pipelines run hundreds of miles and carry the output of many sellers. Attempts by sellers to appropriate rents can

[41] The n-firm concentration ratio is defined as the sum of the shares of the largest n firms in the market. The Herfindahl index is defined as the sum of the squares of the shares of all firms in the market. It can be shown that the "correct" measure of market power is the former if the largest n firms jointly maximize profit (while the rest act as price takers) and the latter if all firms act as Cournot followers; see, for example, Michael Waterson, Economic Theory of the Industry (1984). The reciprocal of the Herfindahl index is equal to the number of Cournot followers if all firms were the same size.

[42] Of the 579 producers in the data base with recorded contract volumes, 350 (60 percent) have only one contract, and 517 (almost 90 percent) have five or fewer.

TABLE 1

MARKET CHARACTERISTICS: CONCENTRATION AND PRICING

MARKET	VOLUME (MMCF/Year) (Number of Contracts)	AVERAGE Price (¢/MCF)	SELLER CONCENTRATION			BUYER CONCENTRATION		
			$C4$	Herfindahl	Number	$C2$	Herfindahl	Number
1. Mississippi	31,783 (68)	19.47	.80	.26	46	1.00	.99	3
2. South Louisiana	221,997 (161)	16.22	.50	.08	58	.52	.20	9
3. Goliad	76,659 (146)	11.37	.28	.03	88	.68	.32	6
4. Houston	46,584 (169)	10.13	.32	.04	89	.77	.39	6
5. Corpus Christi	156,610 (160)	11.08	.46	.10	73	.78	.33	5
6. North Louisiana/ East Texas	200,111 (221)	10.68	.48	.09	95	.69	.30	8
7. North Texas/ Oklahoma	116,730 (223)	9.78	.60	.11	81	.75	.35	7
8. Kansas	38,374 (98)	12.57	.52	.09	48	.95	.80	5
9. Hugoton/ Panhandle	131,242 (354)	13.33	.59	.13	100	.65	.31	7
10. West Texas/ New Mexico	66,840 (105)	9.95	.65	.14	56	1.00	.86	2
11. Rocky Mountains	39,149 (99)	7.49	.70	.17	45 579*	.60	.24	7 33†

NOTE.—Data (except for number of contracts) refer only to contracts with recorded volumes (1,563 or 1,804 contracts). MMCF = million cubic feet. MCF = thousand cubic feet.

* Number of different sellers.

† Number of different buyers.

be met by switching to other sellers in the same market or switching to other markets. A description of pipeline operations in each market is contained in Table 2.

As shown in Table 3, there were, however, a few very large sellers, with many contracts across several markets. During the period covered by the data base, there were ten producers that signed more than thirty contracts. These producers, all large oil companies, also had a sizable stock of existing contracts (see Table 3). One might expect that these firms had both a much better idea of the value of their gas at diverse locations than did the single-contract producers and a better idea of how to negotiate with pipelines. Moreover, reputation effects are important in dealing with such sellers. Pipelines would be less apt to try to capture all of the rents from a partner that they anticipate facing repeatedly in the future.

In an attempt to capture these considerations we employ firm size as an explanatory variable, both within the market (using market share) and across all markets.[43] We can then test whether, for example, the Texas Company (Texaco) is able to obtain a better deal than a small producer for its gas, when market structure and other factors are properly controlled for.[44]

Third, transportation and production cost considerations are important. Our revenue function, R, for the pipeline represents net revenue, so that differences in acquisition costs of gas must be controlled for. Relative to its value, natural gas is expensive to transport. Some gas is worthless because it is further from pipelines or the field is far from consumers. Similarly, a large-volume well is worth more because the cost of connecting the well to the pipeline is fixed and because of the higher pressure associated with such wells.[45,46]

[43] These firm-specific measures are not highly correlated with the market-specific measures of concentration. For example, on the buyer side: corr(C2, H) = 0.916; corr(market share, C2) = 0.367; corr(market share, H) = 0.269; and on the seller side: corr(C4, H) = 0.820; corr(market share, C4) = 0.086; corr(market share, H) = 0.026.

[44] Our discussion suggests using the number of contracts as the appropriate measure of producer size and total volume for pipeline size. Experiments with both volume and number of contracts produced similar results.

[45] Cost savings from large-volume wells are traceable to economies of scale in transmission. It is important to control for this since, on account of lower transport costs for large deliveries, a premium price can be offered to such producers. The sources of cost savings are reductions in construction and operating costs and in costs of rights of way per thousand cubic feet (mcf) of gathered gas. MacAvoy, *supra* note 14, estimates that these volume-driven differences in costs are substantial relative to the average wellhead price.

[46] In this market, there is little question of the statistical exogeneity of volume in considering the price offered a given well. While exploration and drilling may be price sensitive, gas wells, once sunk, produce at maximum sustainable yield because of transmission-cost considerations and the common-pool problem.

TABLE 2

Pipeline Operations by Market

Market	Pipeline	Number of Contracts	Average Price Paid (¢/MCF)	Market Share	Total Volume (MMCF)	Percentage of Buyer Total
Mississippi	United	64	19.82	.997	31,648	33.0
	Texas Eastern	2	19.00	. . .	. . .	. . .
	Southern	1	7.20	.002	55	1.7
	Transcontinental	1	18.00	.001	30	.0
South Louisiana	Transcontinental	39	15.45	.317	70,281	99.2
	United Fuel Gas	36	16.54	.202	44,905	100.0
	American	20	18.65	.182	40,457	100.0
	United	10	17.43	.132	29,198	30.4
	Tennessee	21	15.89	.079	17,619	8.3
	Niagara	2	16.40	.048	10,714	100.0
	Texas Gas Transmission	20	15.90	.033	7,423	16.8
	Trunkline	8	12.23	.005	1,114	1.5
	Southern	5	16.80	.001	286	8.1
Houston	Tennessee	98	10.71	.447	34,271	16.2
	Texas Eastern	18	12.97	.237	18,131	25.7
	Texas Gas Pipeline	11	12.27	.232	17,794	40.2
	Texas-Illinois	9	13.97	.079	6,024	26.2
	Texas Gas Corporation	8	12.35	.005	412	100.0
	Trunkline	1	18.00	.001	30	.0
Goliad	Texas Eastern	108	10.24	.579	26,970	38.2
	Tennessee	27	10.39	.187	8,691	4.1
	United	12	6.92	.101	4,727	4.9
	Trunkline	8	8.00	.078	3,628	4.9
	Texas-Illinois	6	12.60	.044	2,038	9.0
	Transcontinental	8	12.94	.011	530	4.7

Corpus Christi	Trunkline	19	11.87	.433	67,777	91.6
	Tennessee	111	11.95	.348	54,506	25.7
	United	8	11.96	.107	16,813	4.9
	Texas-Illinois	7	11.88	.095	14,904	64.9
	Texas Eastern	1	19.08	.001	2,610	3.7
North Louisiana/ East Texas	Tennessee	25	10.75	.485	97,084	45.8
	Arkansas	76	9.80	.201	40,225	100.0
	Texas Eastern	51	13.01	.114	22,897	32.4
	Texas Gas Transmission	13	11.75	.095	19,096	16.8
	United	34	8.72	.068	13,563	14.1
	Lone Star	10	10.20	.013	2,638	8.7
	Southeastern	7	9.84	.016	3,197	90.4
	Trunkline	1	15.60	.007	1,411	1.9
North Texas/ Oklahoma	Cities Service	54	10.69	.516	60,269	52.8
	Lone Star	132	9.11	.236	27,579	91.3
	Oklahoma	3	10.00	.155	18,101	100.0
	Fort Smith	1	12.78	.073	8,492	100.0
	Consolidated Utilities	27	10.00	.019	2,186	100.0
	Colorado	4	15.00	.000	56	.1
	Northern	2	15.00	.000	47	.2
Kansas	Cities Service	61	11.93	.890	34,159	29.9
	Michigan	2	15.00	.061	2,326	100.0
	Northern	27	13.57	.044	1,704	7.8
	Panhandle	7	13.86	.003	134	1.3
	Zenith	1	10.00	.001	51	100.0
Hugoton/ Panhandle	Colorado	102	13.98	.497	65,203	99.4
	Northern	87	12.90	.153	20,093	92.0
	Cities Service	22	8.91	.150	19,650	17.2
	Natural Gas Pipeline of America	47	15.10	.103	13,572	100.0
	Panhandle	65	13.67	.076	9,960	98.7
	Kansas-Nebraska	28	12.12	.020	2,638	24.9
	Kansas-Colorado	3	12.00	.001	126	100.0

TABLE 2 (*Continued*)

Market	Pipeline	Number of Contracts	Average Price Paid (¢/MCF)	Market Share	Total Volume (MMCF)	Percentage of Buyer Total
West Texas/ New Mexico	El Paso	37	9.73	.926	61,889	82.7
	Permian	68	10.06	.074	4,951	100.0
Rocky Mountains	El Paso	8	11.56	.336	13,149	17.5
	Southern Union	5	7.73	.262	10,273	100.0
	Kansas-Nebraska	50	10.12	.204	7,968	75.1
	Montana-Dakota	5	8.78	.083	3,248	100.0
	Mountain	5	10.72	.060	2,349	100.0
	Pacific	24	12.15	.048	1,862	100.0
	Colorado	2	15.50	.008	300	.5

SOURCE.—Champlin Oil and Refining Co. et al., Federal Power Commission Docket G-9277 (1957–59), exhibit 4-LC.

TABLE 3

TEN LARGEST CONTRACT SIGNERS (Producers)

Firm*	Contracts Signed 1953–57	Contract Signed Pre-1953	U.S. Rank in Natural Gas Production
1. Magnolia Petroleum (Mobil)	52	1	6
2. Texas Co.	50	76	5
3. Sinclair	41	43	16
4. Pan American Production (Standard Oil of Indiana)	38	22	3
5. Sunray Midcontinent	38	70	15
6. Gulf	34	32	8
7. Superior	34	10	17
8. Cities Service	34	56	7
9. Atlantic Refining	32	100	12
10. Shell	31	90	4

SOURCES.—For column 1, Champlin Oil and Refining Co., et al. (FPC Docket G-9277, 1957–59), exhibit 4-LC. Contracts are only those in table 1. For column 2, *ibid.*, exhibit 2-LC, table 1. All interstate contracts still in effect as of 1955 are included. For column 3, American Petroleum Institute, Market Shares and Individual Company Data for U.S. Energy Markets: 1950–83 (Discussion Paper No. 014P, November 1984). The figures are for 1955.

* These are the firm names in use at the time. Many of the firms have changed ownership or name; affiliated firms are in parentheses.

We are no more able to establish costs than was the FPC staff in the 1950s, so we employ proxies—the distance of the market from consuming regions (represented by region dummies),[47] the density of wells per county (higher density means lower fixed cost of gathering lines to transport gas from wellhead to pipeline), and the volume of the contract. An additional consideration in measuring cost differences is distinguishing the more common gas-well-gas and occasional oil-well-gas contracts; the latter represent gas produced jointly with oil (thus at a substantially lower marginal cost than gas-well gas). The main body of data we use did not contain this information. By matching contact information with ancillary data in exhibit 2-LC of the *Champlin* case FPC docket, we were able to exclude oil-well-gas contracts from the analysis.

Finally, we include two additional factors that affect the size of the rent to be divided. The common-pool nature of producing from underground fields serves to reduce the rent available to be split between buyer and seller. As a rough measure of the extent of the common-pool problem, we use the number of sellers producing in the given field; the more sellers per field, the greater the potential problem. The large number of pools in each market prevents a multicollinearity problem with the seller market-structure variables. The level of demand is clearly important; we employ dummy variables for each year after 1953 because a secular increase in demand caused prices to rise over the period.[48]

Whereas we follow the industrial organization literature in treating the number and size of buyers and sellers (as measured by concentration ratios and Herfindahl indices) in a given market as elements of market structure, Mulherin uses the number of buyers and sellers in a given field as a proxy for asset specificity, a transaction-cost measure.[49] Since our results depend on proper identification of market-structure and transaction-cost variables, it is worth justifying the differences here.

[47] We also experimented with a variable representing the distance of the market from consuming regions. The variable was constructed using FPC maps, by measuring the distance along major pipeline routes from the center of each market to selected reference points; the method of construction is available from the authors on request. The coefficient on this variable in the price equations was always statistically insignificantly different from zero, and its inclusion did not affect our estimates of other coefficients; we exclude the variable from the results reported in Table 5. Because of this problem and since distances are not comparable across regions (because of, for example, varying terrain, weather, and rights of way), we include dummy variables for the Midcontinent and Rocky Mountain regions.

[48] Dummy variables are appropriate here only if the slope of the demand curve is constant. We have used them to avoid estimating a demand function, which would lead us into simultaneity problems.

[49] See Mulherin, *supra* note 38.

First, Mulherin's concern (and that of Masten and Crocker)[50] over the common-pool problem's effect on seller bargaining power motivates his (and their) inclusion of the number of sellers per field as a transaction-cost-related measure. Because we use seller-specific data, and because common-pool effects are by their very nature identical across contracts in a given field, we treat these effects (as proxied by the number of sellers per field) as part of costs and include them as controls, in addition to our market-structure and transaction-cost-related variables. Our concentration measures, in contrast, are for entire markets, which include many fields (many of which are relatively small).

Second, Mulherin uses the number of sellers per field to explain (through whether the contractual delivery point is at the well or the pipeline) the provision for the ownership of the gathering system that carries gas in the field to the pipeline. This provision is likely to be related to the number of sellers in the field because the cost of the gathering system is largely fixed and is spread over the various wells to which the system connects. Thus its inclusion as a transaction-cost-related variable arguably makes sense for the purpose that Mulherin uses it.

Finally, our use of buyer concentration measures for each market as a measure of market structure is similar to that of Masten and Crocker, who also included the number of buyers per field as a transaction-cost-related variable.[51] As discussed above, our view of transaction costs is one closely related to games with asymmetric information, for which the use of and seller size is a more appropriate proxy for bargaining power than the number of buyers or sellers in a given field.

IV. Empirical Tests of Determinants of Contract Prices: Reduced-Form Model

The specification of our reduced-form price equation is

$$P_{ijkt} = \alpha + \mu M_k + \omega w_{ijk} + \Omega W_{ij} + \gamma C_{ijk} + \delta D_t + \epsilon_{ijkt}, \qquad (7)$$

where i indexes sellers, j buyers, k markets, and t years; P_{ijkt} is the initial price in a contract signed between the ith seller and the jth buyer in the kth market in the tth year; M is a vector of variables related to market structure; w a vector of characteristics of pipelines and producers within the market where the transaction takes place; W a vector of variables associated with the contracting parties across markets; C a vector of transportation cost variables; D a vector of time dummy variables; ϵ an

[50] See Masten & Crocker, *supra* note 3.

[51] *Id.*

additive disturbance; and α, μ, ω, Ω, γ, and δ are coefficients to be estimated. In the absence of small-numbers-bargaining problems, we expect prices in a given field to depend only on market characteristics (transportation costs, level of demand, and buyer and seller concentration) and not on characteristics of specific contracting firms.

Equation (7) was estimated by ordinary least squares using data on contracts in markets 2–10.[52] Market 1 (Mississippi) was omitted because no distinction is made between firm and market characteristics (as shown in Table 1, there was only one buyer in this market); there are few contracts in the market; and most of these contracts are in a single county near the Louisiana (market 2) border. Market 11 (Rocky Mountains) was omitted because it covers not one market, but a large number of small, isolated fields stretching from the Four Corners area of the southwest to the Canadian border. Thus, the only Rocky Mountain contracts used are those from market 10 (West Texas/Southeast New Mexico). As a result of these omissions and incomplete information in some of the contracts, 1,424 contracts are available for use in the empirical analysis. Because we later estimate jointly models of the determinants of price and the use of an MFN clause, we restrict our analysis to the 1,102 contracts with information on both.[53]

Table 4 contains the means of the explanatory variables. Table 5 reports the regression results for the contract-price equation. The results in Table 5 are present for the categories of variables described previously. Two sets of market structure variables were used: the concentration ratios on the buyer (two-firm) and seller (four-firm) sides, and the Herfindahl indices for buyers and sellers. In addition, two sets of variables were employed as measures of absolute size of buyers and sellers: buyer and seller total volume and total number of contracts, and buyer total volume and seller total contracts. The latter represent the case for which seller size and access to information about market conditions is proxied by the number of contracts, while pipelines, with their better access to information about market conditions, are indexed for size by their total volume.

[52] Some motivation for this particular approach is needed. MacAvoy, *supra* note 14, examined price equations for each FPC market separately over various periods covered by the data. This strategy would not be appropriate for our purposes, since we want to consider the influence of both market- and transaction-related variables on price determination. We did, however, examine the robustness of our estimates (in Table 5) of the effects of transaction-related variables by using fixed market effects instead of our measures of market concentration on the buyer and seller sides. The fixed effects reflected the patterns predicted by the market structure variables, and the coefficient estimates on the firm and transaction variables of interest were similar to those reported in Table 5.

[53] The results reported in Table 5 are robust to estimation over the full set of 1,424 contracts.

TABLE 4

MEANS OF EXPLANATORY VARIABLES IN PRICE EQUATION

Variable	Mean Value
Market-specific variables:	
Seller concentration (*C*4)	.51
Seller Herfindahl	.11
Buyer concentration (*C*2)	.72
Buyer Herfindahl	.38
Transaction-specific variables:	
Seller market share	.02
Buyer market share	.29
Seller size (total volume in million cubic feet)	.10
Buyer size (total volume in million cubic feet)	1.04
Seller size (total contracts)	14.1
Buyer size (total contracts)	134.4
Cost variables:	
Contract volume (in million cubic feet)	.075
Gathering-cost proxy (volume per square mile in county)	19.0
Other variables:	
Common-pool proxy (sellers per field)	13.8

Apart from other conditions, the yearly dummy variables indicate generally a rising profile of prices over the period.

The coefficients on the buyer and seller concentration ratios yield evidence of pipeline monopsony power, though there is no evidence of a positive association between producer concentration and the price received by producers in the contract. These results are consistent with much of the discussion of the gas market by economists in the 1950s: the anticompetitive problems that might exist were most likely to come from the buyer, not the seller. Similar findings occur on the buyer and seller sides when the Herfindahl index is used.

The coefficient estimates in Table 5 reflect the importance of transaction-specific and firm-specific characteristics in contract-price determination. Measures of buyer and seller size in the market are associated with negative and positive effects, respectively, on the price. Our indicators of the effects of absolute size of transacting parties reveal that the number of contracts is more important than size measured by total volume, most likely reflecting the information-gathering process associated with having many contracts.[54] Increases in the number of producer contracts raises the contract price, while the opposite is true for buyers. In

[54] This is probably more important for producers than for pipelines, who have better information about downstream demand conditions. Indeed, when we include only producer volume and buyer total contracts, the same pattern emerges.

TABLE 5

PRICE DETERMINATION IN PRODUCER-PIPELINE CONTRACTS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Market-specific variables:								
Seller concentration ratio	1.49	1.95	...	...	1.35	1.76	...	...
	(1.49)	(.98)			(.99)	(.97)		
Buyer concentration ratio	−9.78	−6.12	...	...	−10.52	−6.73	...	...
	(11.6)	(5.75)			(12.72)	(6.37)		
Seller Herfindahl index	...	...	1.57	.02	...	...	3.50	4.87
			(.47)	(.01)			(1.04)	(1.45)
Buyer Herfindahl index	...	...	−.91	−.82	...	...	−1.30	.15
			(1.36)	(.96)			(1.87)	(.18)
Transaction-specific variables:								
Seller market share	5.57	7.27	4.63	6.46	4.82	6.16	5.56	7.01
	(2.79)	(3.63)	(2.16)	(2.18)	(2.63)	(3.41)	(2.78)	(3.47)
Buyer market share	.30	.63	−.88	−.28	.66	.98	−.36	.16
	(.93)	(1.94)	(2.45)	(.72)	(2.04)	(3.08)	(1.00)	(.41)
Seller size (total volume $\times 10^{-5}$)	−.10	−.13	−.005	−.04	...	...	...	...
	(1.41)	(1.81)	(.07)	(.53)				
Buyer size (total volume $\times 10^{-5}$)	.26	.26	.64	.64	−.26	−.25	−.42	.16
	(1.80)	(1.83)	(4.12)	(4.19)	(3.12)	(3.01)	(4.58)	(4.70)
Seller size (total contracts)	.02	.02	.02	.02	.01	.01	.02	.014
	(3.06)	(3.25)	(2.80)	(2.97)	(2.47)	(2.36)	(3.15)	(2.90)
Buyer size (total contracts)	−.006	−.006	−.012	−.013	...	...	...	...
	(−4.39)	(4.23)	(8.31)	(8.45)				
Cost variables:								
Midcontinent dummy	−.12	−.12	−.79	−.74	−.28	−.27	−1.08	−1.05
	(.43)	(.43)	(3.00)	(2.83)	(.99)	(.98)	(4.03)	(3.94)
Rocky Mountain dummy	.71	−.01	−1.35	−2.02	.88	.11	−1.16	−1.68
	(1.40)	(.03)	(−2.37)	(3.22)	(1.71)	(.21)	(2.00)	(2.61)

Contract volume ($\times$ 10^{-5})	4.21	6.44	4.72	1.87	5.15	6.32	7.10	2.25
	(1.70)	(4.97)	(1.78)	(3.29)	(2.07)	(4.85)	(2.60)	(3.87)
Gathering-cost proxy (volume per square mile in the country)	−.005	.103	−.001	.032	−.006	.107	−.002	.024
	(1.85)	(3.84)	(.40)	(2.81)	(2.17)	(3.93)	(.70)	(2.05)
Buyer concentration measure × contract volume	. . .	−8.71	. . .	−4.57	. . .	−8.41	. . .	−4.99
		(4.79)		(2.90)		(4.60)		(3.09)
Buyer concentration measure × gathering-cost proxy	. . .	−.152	. . .	−.104	. . .	−.16	. . .	−.08
		(4.02)		(2.97)		(4.14)		(2.27)
Other variables:								
Constant term	17.63	14.64	12.63	11.73	17.36	14.31	11.60	10.83
	(21.65)	(15.25)	(0.40)	(24.97)	(21.19)	(14.82)	(29.39)	(22.93)
Common-pool proxy (sellers per field)	−.03	−.03	−.03	−.035	−.033	−.038	−.042	−.046
	(4.27)	(5.12)	(4.42)	(4.86)	(4.92)	(5.74)	(5.75)	(6.20)
1954 dummy	−.74	−.64	−.81	−.75	−.63	−.53	−.59	−.53
	(3.92)	(3.43)	(4.01)	(3.73)	(3.34)	(2.87)	(2.86)	(2.57)
1955 dummy	1.04	1.11	.92	1.00	1.18	1.25	1.20	1.29
	(5.33)	(5.84)	(4.40)	(4.83)	(6.11)	(6.61)	(5.68)	(6.08)
1956 dummy	2.30	2.32	2.24	2.27	2.42	2.43	2.48	2.52
	(12.16)	(12.50)	(10.94)	(11.17)	(12.81)	(13.11)	(11.92)	(12.16)
1957 dummy	2.42	2.42	2.42	2.43	2.68	2.67	2.95	2.97
	(9.67)	(9.81)	(9.02)	(9.10)	(10.88)	(11.00)	(10.96)	(11.11)
Summary statistics:								
N	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102
$\overline{R}^2$	.44	.46	.36	.37	.43	.45	.32	.34
F	51.6	50.8	36.9	34.7	56.0	54.4	35.1	32.4
F-tests for exclusion (Significance Levels):								
Seller and buyer concentration	.0001	.0001	.3943	.6128	.001	.001	.0478	.3427
Transaction-specific variables	.0110	.0001	.0001	.0001	.0001	.0001	.0001	.0001
Cost variables	.0023	.0001	.0113	.0001	.0001	.0001	.0001	.0001

NOTE.—Absolute values of t-statistics (with respect to heteroskedasticity-consistent standard errors) are in parentheses.

general, the variables specific to transacting parties are relatively more important on the seller side than the buyer side, where market-specific effects dominate. For example, spanning the range of our sample, very large producers with 100 contracts receive prices about 9 percent greater than very small producers with only one contract.

Finally, on the cost side, the positive coefficient on the contract volume reflects the significance of the fixed cost of connecting the individual well to the pipeline. The gathering-cost proxy was imprecisely estimated; the coefficients on the region dummies reflected the greater proximity of the Midcontinent and Rocky Mountain regions to final markets. The negative and statistically significant coefficient on the number of sellers per field indicates the importance of the common-pool problem. We test further for momopsony power by allowing the coefficients on the cost proxies (well volume and gathering cost) to vary with the degree of buyer concentration. The negative estimated coefficients on the cost-concentration interactions indicate that the rents from being a low-cost producer accrue in part to buyers in markets with a high degree of concentration on the pipeline side.

The results in Table 5 are indicative of the importance of small-numbers-bargaining issues in the gas market. Based on the F-tests reported in the table, we can reject at any reasonable significance level the hypotheses that the numbers of buyer and seller contracts, the combination of volumes and numbers of contracts, and the combination of volumes, numbers of contracts, and market shares should not be included in the contract-price equation. We also cannot reject the joint inclusion of buyer and seller concentration ratios, though only the former is individually consistent with the seller-market-power hypothesis.

V. Determinants of Use of the Most-Favored-Nation Clause

A. *Market-Power or Transaction-Cost Influences?*

As noted before, the most-favored-nation clause raises the contract price to the level of the highest price paid by the pipeline on any new contracts in the field.[55] Table 6 illustrates the use of MFN clauses in the various field markets included in our data. Their use differed considerably

[55] This is true under a two-party MFN clause. There are also a few three-party MFNs where the pipeline is obliged to match the highest price on new contracts signed by any pipeline in the area. Definitions of the relevant area vary; the most common procedure was to specify a list of counties (see *Champlin Oil, supra* note 29, exhibit 2-LC, table 3). The relatively small size of most counties suggests that the areas are within the same field as the contract, or neighboring fields within the same market.

TABLE 6

USE OF MOST-FAVORED-NATION PROVISION

Market	Percentage of Contracts Covered by MFN
1. Mississippi	.0
2. South Louisiana	76.1
3. Houston	82.1
4. Goliad	83.4
5. Corpus Christi	91.1
6. North Louisiana/East Texas	57.5
7. North Texas/Oklahoma	68.0
8. Kansas	54.1
9. Hugoton/Panhandle	.8
10. West Texas/New Mexico	46.7
11. Rocky Mountains	33.8
All markets	51.9

across markets.[56] Below we contrast the predictions of the transaction-cost and market-power views. During the 1950s, concern over the use of MFNs was based on their supposed origins in producer market power.[57] Such arguments would suggest that MFNs should appear most frequently in contracts in markets with relatively high seller concentration.

As in the model of the initial contract price, we include both market-structure variables (buyer and seller concentration ratios or Herfindahl indices) and transaction-specific variables (measuring buyer and seller size absolutely and within specific markets). Time dummies are included, as are dummies for the Midcontinent and Rocky Mountain regions (to reflect differences in "maturity" of the regions). That is, we consider a probit model of the form

$$\mathrm{MFN}_{ijkt} = f(M_k, w_{ijk}, W_{ij}, D_t), \tag{8}$$

where "MFN" takes on the value of one when a two-party MFN is used in the contract, and zero otherwise. The variables are as defined in the price model.

[56] State maximum-price laws in Kansas and Oklahoma that applied to contracts in the Hugoton-Panhandle field virtually eliminated the use of MFN clauses there. Indeed, examination of ancillary data (in *Champlin Oil, supra* note 29, exhibit 2-LC) revealed several cases in which when an initial price was less than the legislated price, contract prices were adjusted accordingly. In later years, these laws were struck down because of conflicting jurisdiction with the FPC as a result of the *Phillips* case (see MacAvoy, *supra* note 14, at 232; and Cities Service Gas Co. v. Kansas State Corp. Comm., 355 U.S. 391, 1958). Affected contracts were excluded from our analysis of determinants of the use of MFNs.

[57] See Hearings on HR4560, Exemption of Gas Producers, Part I and II (1955), and the discussion in Neuner, *supra* note 34.

Additional questions as to the definition of market boundaries arise in the consideration of MFN clauses. One potential cost of MFN stems from the obvious pecuniary externality problem stressed by Neuner and MacAvoy.[58] Resources may be wasted as pipelines switch fields to avoid triggering MFNs. We include in the model in equation (8) a buyer-escape variable measuring the fraction of a pipeline's total volume accounted for outside the contract's market. The expected sign on this variable is ambiguous. On the one hand, a higher value of buyer escape makes the pipeline more willing to grant an MFN, ceteris paribus; on the other hand, higher values make the potential for field-switching greater, making the clause of less value to producers.[59]

Specific tests are formulated as follows. A market-power interpretation of the occurrence of MFNs would imply a positive effect of producer concentration and a negative effect of pipeline concentration. The contracting interpretation suggests that market-structure variables are irrelevant but that informational asymmetries and the potential for opportunistic behavior (and hence the value of the MFN) are greater, ceteris paribus, the larger the buyer or the smaller the seller.

Probit results are presented in Table 7 for the same markets and groupings of transaction-related variables considered in Table 5; the results are consistent with the contracting approach outlined earlier. Coefficients on neither the buyer nor seller concentration ratio are statistically significantly different from zero; the producer-concentration-ratio coefficient even has the opposite sign from that predicted by the market-power hypothesis. Coefficients on the Herfindahl measures are statistically significant, though the producer index still has the wrong sign for the market-power explanation. Coefficients on buyer and seller size indicate that large buyers and small sellers (both in the market and in absolute size) are more likely to have an MFN in their contracts. In particular, the coefficient on seller size measured by number of contracts is negative and precisely estimated. The estimated negative coefficients on buyer escape suggest that the field-switching problem may well have been important. The Rocky Mountain and Midcontinent dummies have the expected negative signs, reflecting the more infrequent use of MFNs in those relatively mature regions.

These results from the reduced-form model provide support for the hypothesis that the MFN is part of a contractual package designed to approximate marginal efficiency over the course of a long-term contract

[58] See Neuner, *supra* note 34; and MacAvoy, *supra* note 14.

[59] See the discussion in David A. Butz, Long-Term Contracting in Field Markets for Natural Gas: A New Perspective on the Most-Favored-Nation Provision (unpublished Ph.D. dissertation, Northwestern Univ. 1986).

TABLE 7

DETERMINANTS OF USE OF MOST-FAVORED-NATION CLAUSE

	(1)	(2)	(3)	(4)
Market-specific variables:				
Seller concentration	−1.29	−1.55	. . .	. . .
	(1.48)	(1.94)		
Buyer concentration	−1.91	−.56	. . .	. . .
	(2.79)	(.85)		
Seller Herfindahl	. . .	. . .	−4.36	−4.54
			(1.62)	(1.82)
Buyer Herfindahl	. . .	. . .	−1.23	−1.12
			(2.26)	(2.08)
Transaction-specific variables:				
Seller market share	−2.17	−1.06	−2.30	−1.07
	(1.43)	(.89)	(1.52)	(.90)
Buyer market share	2.26	1.74	2.32	1.96
	(8.02)	(6.56)	(7.62)	(6.83)
Seller size (total volume)	.003	. . .	−.002	. . .
	(.23)		(.03)	
Buyer size (total volume)	−.030	.66	−.019	.62
	(.23)	(7.37)	(.14)	(6.64)
Seller size (total contracts)	−.010	−.012	−.011	−.012
	(2.23)	(3.78)	(2.34)	(3.65)
Buyer size (total contracts)	.009	. . .	.010	. . .
Other variables:	(8.22)		(7.98)	
Buyer escape	−1.22	−1.20	−1.19	−1.03
	(6.67)	(6.63)	(6.04)	(5.37)
Midcontinent dummy	−.42	−.24	−.53	−.246
	(1.99)	(1.18)	(3.06)	(1.49)
Rocky Mountain dummy	−.15	−.47	−.10	−.035
	(.38)	(1.23)	(.23)	(.085)
Constant term	1.48	1.09	.35	.64
	(2.13)	(1.65)	(1.17)	(2.26)
Summary statistics:				
N	1,102	1,102	1,102	1,102
χ^2	965.4	966.7	1,039.3	1,036.4

NOTE.—Coefficients on year dummies are not reported. Absolute values of t-statistics are in parentheses.

(by making price changes responsive to growth in demand), while allowing inframarginal rents to be distributed between producer and pipeline according to differences in bargaining power. Our findings point up the need to consider contractual provisions together as part of a bargain and not focus individually on price and nonprice competition. Policy proposals to restrict the use of particular provisions are likely to be inappropriate.[60]

[60] This point is discussed in the context of current policy debates over the take-or-pay provision in Hubbard & Weiner, *supra* note 3; and Masten & Crocker, *supra* note 3. MFN provisions were restricted as anticompetitive in the 1960s.

B. *Alternative Explanations*

One alternative explanation of the use of the MFNs is as an anticompetitive device on the buyer side.[61] That is, if each pipeline in a given market offered a two-party MFN in its contracts, competitive bidding would be discouraged—buyers, by competing for new suppliers, would trigger price increases in existing contracts. The difficulties with this explanation are three. First, the presence of an MFN clause (in the data) is negatively associated with concentration on the buyer side. Second, credible punishments would have to be explained; pipelines not using the MFN can take advantage of their rivals. Third, entry barriers must be substantial to forestall competition from potential rivals. These criticisms are serious. The estimates in Table 7 suggest that buyers with large market shares are more likely to have MFNs in their contracts. Moreover, in an examination of the Southern Louisiana market over the 1946–55 period, Butz concludes that MFNs are used extensively even though the market was growing rapidly with substantial pipeline entry.[62]

A second alternative emphasizes insurance features of contracts. While the model in Section II assumed that buyers and sellers are risk neutral, more generally, contractual provisions may redistribute risks between risk-averse contracting parties. In related work, we derived the optimal mix of spot (flexible-price) and contract (fixed-price) trades as a function of market characteristics and the risk aversion of buyers and sellers.[63] Suppose, for example, that pipelines and large corporate producers are risk neutral and small, undiversified producers are risk averse. If uncertainty stems principally from the demand side (as opposed to uncertainty over production costs), then small producers would prefer a fixed-price contract and large producers would prefer a flexible-price contract.[64] This prediction is not borne out by the results in Table 7.[65,66]

[61] See Thomas E. Cooper, Most-Favored-Customer Pricing and Tacit Collusion, 17 Rand J. Econ. 377 (1986); and Steven C. Salop, Practices That (Credibly) Facilitate Oligopoly Coordination, in New Developments in the Analysis of Market Structure (Joseph E. Stiglitz & G. Frank Mathewson eds. 1986).

[62] See Butz, *supra* note 59.

[63] See Hubbard & Weiner, *supra* note 4.

[64] *Id.*

[65] The same intuition holds in the case of a contract with a floor price. Very risk-averse sellers would prefer a high fixed price, while less risk-averse sellers would prefer a lower floor price with variable adjustment (see Polinsky, *supra* note 4).

[66] An additional possibility here stems from risk preferences induced by regulation; that is, regulation can induce risk-averse behavior (if a ceiling on profits is imposed) or risk-loving behavior (if a minimum return is guaranteed), even if participants are actually risk

VI. Joint Estimation of Price and Most-Favored-Nation-Clause Models

The reduced-form models outlined in Sections IV and V indicate the potential importance of transaction-specific factors (over and above market-specific conditions) in the contract bargain. Given the role of transaction-specific factors in influencing the use of an MFN clause, it is possible that the estimated effect of transaction variables in the price equation just reflects the tradeoff between the price and the MFN clause in the initial bargain. Including a dummy variable for the presence of an MFN clause in the price equation would not be sufficient since the two contract terms are determined simultaneously.

To consider this issue, we begin with the following form of the price equation:

$$P = \begin{cases} X'\beta + W'\delta_1 + \epsilon_1, & \text{if MFN} = 1, \\ X'\beta + W'\delta_0 + \epsilon_0, & \text{if MFN} = 0, \end{cases} \tag{9}$$

where

$$\text{MFN} = \begin{cases} 1, & \text{if } Z'\gamma - u > 0, \\ 0, & \text{otherwise}, \end{cases} \tag{10}$$

and W is a vector of transaction-specific variables; X is a vector of other variables in the price equation; Z is a vector of exogenous variables in the MFN equation; and ϵ_0, ϵ_1, and u are error terms.

Including a dummy variable for MFN in the price equation would imply an exogenous switching process, appropriate only if the error terms ϵ_0 and ϵ_1 are uncorrelated with u (the error term). We correct for potential simultaneity bias by estimating the price equation as an endogenous switching regression (that is, price and MFN are jointly determined as endogenous variables), wherein the dummy variable MFN is replaced on the right-hand side of the price equation by its fitted value from probit models analogous to those presented in Table 7.[67]

Specifically, we assume that u, ϵ_0, and ϵ_1 are jointly normally distrib-

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neutral. See Ronald R. Braeutigam & James P. Quirk, Demand Uncertainty and the Regulated Firm, 70 Int'l Econ. Rev. 45 (1984). During the period covered by our study, price ceilings were not binding for producers. The observed variation in the use of MFNs across markets by the same pipeline is not supportive of the regulation-cum-risk-preference explanation on the pipeline side.

[67] See Lung-Fei Lee & Robert P. Trost, Estimation of Some Limited Dependent Variable Models with Application to Housing Demand, 8 J. Econometrics 357 (1978).

uted, and let Φ and ϕ denote, respectively, the cumulative normal density and the normal density:[68]

$$\begin{aligned} E(P) = X'\beta &+ [W'\delta_1 + E(\epsilon_1 | u < Z'\gamma)] \text{ prob } (u < Z'\gamma) \\ &+ [W'\delta_0 + E(\epsilon_0 | u \geqq Z'\gamma)] \text{ prob } (u \geqq Z'\gamma). \end{aligned} \tag{11}$$

Using standard results on the truncated normal distribution, this can be rewritten as[69]

$$\begin{aligned} E(P) &= X'\beta + (W'\delta_1 - \delta_{1u}\phi/\Phi)\Phi + (W'\delta_0 + \delta_{0u}\phi/(1 - \Phi))(1 - \Phi) \\ &= X'\beta + W'\delta_0 + \Phi W'(\delta_1 - \delta_0) + \phi(\delta_{0u} - \delta_{1u}), \end{aligned} \tag{12}$$

or[70]

$$P = X'\beta + W'\delta_0 + \Phi W'(\delta_1 - \delta_0) + \phi(\delta_{0u} - \delta_{1u}) + \eta. \tag{12'}$$

We can estimate (12′) using ordinary least squares with estimates $\hat{\Phi}$ and $\hat{\phi}$ used in place of the true Φ and ϕ, which are not known. The procedure is to first obtain an estimate $\hat{\gamma}$ of γ from the maximum likelihood probit model for MFN, then, using $\hat{\gamma}$, construct $\hat{\Phi}$ and $\hat{\phi}$. The next step is to estimate (12′) by ordinary least squares using the estimates $\hat{\Phi}$ and $\hat{\phi}$. We estimate the endogenous switching model described above for the price models outlined in columns 2, 4, 6, and 8 of Table 5. The first stage estimates the likelihood of a MFN clause in the contract from the probit models in Table 7 with similar right-hand-side variables. Estimated coefficients for the endogenous switching model are reported in Table 8.

An efficient-contracting interpretation of the combination of price and

[68] That is, Φ and ϕ represent:

$\Phi(Z'\gamma) = \text{prob}(u < Z'\gamma) = \text{prob(regime 1)},$

and

$\phi(Z'\gamma) =$ standard normal density evaluated at $Z'\gamma$.

[69] See G. S. Maddala, Limited-Dependent and Qualitative Variables in Econometrics (1982).

[70] Here,

$$\begin{aligned} \eta = (\text{MFN})\epsilon_1 &+ (1 - \text{MFN})\epsilon_0 + (\text{MFN} - \Phi)W'(\delta_1 - \delta_0) \\ &+ (\Phi - \hat{\Phi})W'(\delta_1 - \delta_0) + (\phi - \hat{\phi})(\delta_{0u} - \delta_{1u}). \end{aligned}$$

The usual ordinary-least-squares standard errors are incorrect for two reasons: (1) the true error is conditionally heteroskedastic; and (2) $\hat{\phi}$ and $\hat{\Phi}$ are estimated, as opposed to being known a priori. We follow the procedure outlined in Lee, Maddala, and Trost to construct the correct covariance matrix for the estimated coefficients. See Lung-Fei Lee, G. S. Maddala, & Robert P. Trost, Testing for Structural Change by D-Methods in Switching Simultaneous Equation Models, J. Am. Stat. Assn. Proc. 461 (1979).

TABLE 8

CONTRACT PRICE DETERMINATION: ENDOGENOUS SWITCHING MODEL

	(1)	(2)	(3)	(4)
Market-specific variables:				
Seller concentration ratio	2.60	1.80	. . .	. . .
	(.96)	(1.01)		
Buyer concentration ratio	−9.30	−6.96	. . .	. . .
	(8.67)	(6.58)		
Seller Herfindahl index	. . .	. . .	5.63	−1.58
			(1.71)	(.47)
Buyer Herfindahl index	. . .	. . .	−5.02	−.11
			(4.95)	(.12)
Transaction-specific variables:				
Seller market share	11.94	14.49	9.89	13.33
	(2.47)	(2.32)	(1.82)	(1.98)
Buyer market share	−3.91	.82	−4.76	−2.13
	(2.86)	(.63)	(3.05)	(1.46)
Seller size (total volume $\times$ 10^{-5})	. . .	−.095	. . .	.025
		(.42)		(.10)
Buyer size total volume $\times$ 10^{-5})	.36	−1.49	.71	−1.57
	(.76)	(2.79)	(1.37)	(2.68)
Seller size (total contracts)	.026	.052	.010	.042
	(2.01)	(2.84)	(.62)	(2.09)
Buyer size (total contracts)	. . .	.008	. . .	.004
		(1.83)		(.43)
$\hat{\Phi}$ $\times$ seller market share	−10.79	−11.15	−8.46	−9.09
	(1.76)	(1.51)	(1.24)	(1.14)
$\hat{\Phi}$ $\times$ buyer market share	3.94	−.88	2.53	3.16
	(2.66)	(.60)	(1.50)	(1.91)
$\hat{\Phi}$ $\times$ seller size (volume)	. . .	−.04	. . .	−.10
		(.14)		(.33)
$\hat{\Phi}$ $\times$ buyer size (volume)	−1.33	2.23	−2.14	2.78
	(2.43)	(3.67)	(3.60)	(4.14)
$\hat{\Phi}$ $\times$ seller size (contracts)	−.038	−.050	−.016	−.032
	(2.34)	(2.21)	(.87)	(1.29)
$\hat{\Phi}$ $\times$ buyer size (contracts)	. . .	−.024	. . .	−.026
		(4.07)		(3.96)
Cost variables:				
Midcontinent dummy	.09	−.06	−.54	−.63
	(.31)	(.23)	(1.93)	(2.36)
Rocky Mountain dummy	.45	−.37	.51	−1.97
	(.85)	(.71)	(.75)	(2.99)
Contract volume ($\times$ 10^{-5})	5.58	5.90	2.05	1.71
	(4.45)	(4.74)	(3.67)	(3.09)
Gathering-cost proxy (volume per square mile in the county)	.037	.080	−.044	.027
	(1.30)	(2.87)	(3.19)	(2.11)

TABLE 8 (*Continued*)

	(1)	(2)	(3)	(4)
Buyer concentration measure × contract volume	−7.31	−7.99	−4.40	−4.24
	(4.13)	(4.57)	(2.81)	(2.75)
Buyer concentration measure × gathering-cost proxy	−.060	−.120	.143	−.092
	(1.41)	(3.05)	(3.30)	(2.28)
Other variables:				
Constant term	16.62	13.20	14.23	9.47
	(13.52)	(12.89)	(14.52)	(13.21)
Common-pool proxy (sellers per field)	−.045	−.035	−.0521	−.036
	(7.00)	(5.44)	(7.23)	(5.00)
1954 dummy	−.55	−.63	−.56	−.74
	(3.08)	(3.54)	(2.86)	(3.81)
1955 dummy	1.27	1.19	1.25	1.06
	(6.92)	(6.48)	(6.10)	(5.23)
1956 dummy	2.52	2.42	2.54	2.34
	(13.87)	(13.24)	(12.45)	(11.62)
1957 dummy	2.85	2.57	3.16	2.56
	(11.82)	(10.63)	(11.89)	(9.67)
$\hat{\Phi}$	2.52	3.97	3.04	4.15
	(4.25)	(7.15)	(4.47)	(6.60)
$\hat{\phi}$	−5.86	−1.55	−8.92	−1.03
	(4.65)	(1.41)	(6.24)	(.81)
Summary statistics:				
N	1,102	1,102	1,102	1,102
$\bar{R}^2$	.50	.51	.38	.41
F	47.7	42.6	29.8	28.8
F-tests for exclusion (significance levels):				
MFN interactions	.0005	.0001	.0013	.0001

NOTE.—Absolute values of t-statistics (with respect to heteroskedasticity-consistent standard errors) are in parentheses.

MFN provisions would suggest that (1) MFNs are most likely to be used in growing markets with significant entry so that, ceteris paribus, high prices and the use of MFNs go hand in hand; and (2) holding constant the presence of an MFN in contracts, the effects of transaction-specific characteristics on price should not be important. This pattern stands in contrast to the notion of a simple tradeoff between price and the MFN provision, in which MFNs would be used primarily in low-price markets, irrespective of transaction-specific characteristics.

Given the estimated coefficients in Table 8, one can easily reject the hypothesis of a unique tradeoff between initial price and MFN clauses in producer-pipeline contracts. The effects of characteristics of transacting parties on contract prices vary significantly between contracts with and without MFN provisions. In particular, the positive impacts on price of seller market share and seller size (measured by the number of contracts) are traceable to contracts without MFN provisions; such effects are negligible in contracts with MFNs. Similarly, the negative association of buyer market share and price in the reduced-form model is a feature of contracts not containing an MFN clause. These characteristics of the transacting parties affect the likelihood of contracts' including two-party MFN clauses (see Table 7) and, in so doing, affect the contract price.

All other things being equal, small sellers received higher prices in contracts with MFNs; they are more likely as well to have an MFN provision. We also know from previous discussion that MFNs were most often used in growing markets. Hence the pattern of MFNs is consistent with their being used to permit flexible price adjustment in the presence of growing demand. The results in Table 8 are inconsistent with a static seller-market-power interpretation, in which a tradeoff between price and MNF would be related only to market-specific characteristics. Similarly, if use of MFNs reflected primarily tacit collusion among buyers (which we noted earlier was unlikely a priori), any estimated negative effect of buyer market share on price should be greater in the presence of an MFN provision; just the opposite is true.

VII. Conclusions and Implications

It is well recognized by economists that long-term contracting under an array of price and nonprice provisions may be an efficient response to small-numbers bargaining problems. Empirical work to distinguish such issues from predictions of models of market power and bargaining has been sparse, principally because the necessary data on individual transactions are seldom publicly available. The U.S. natural gas industry is well suited for such tests because of both the small number of buyers (pipelines) and sellers (producers) in each market and the large capital commitments required of transacting parties at the beginning of the contract.

In this article, we make use of a large detailed data set on contracts between U.S. natural gas producers and pipelines signed during the 1950s. With respect to the determination of the initial price in the contract, principal results are two. First, static market-power influences are not the only factors in contract price determination. While there is some evidence of pipeline monopsony power, there is no evidence for positive effects of producer market power (as measured by concentration) on contract prices. Second, transaction-specific and firm-specific variables are important, including measures of buyer and seller market share and size indicated by total volume or total number of contracts.

The key test of the relative role played by transaction considerations is to assess how prices adjust over time. Use of the most-favored-nation clause in this respect cannot be explained by producer market power; indeed the provision is used by large buyers and small sellers to approximate the flexible marginal compensation under growing demand suggested by the model in Section II.

We have discussed many problems associated with arm's-length transactions in field markets for natural gas, including specific capital, unspecified property rights, and asymmetric information. Exchange is complicated still further by a regulatory framework that has been attacked as both inefficient and inequitable. Recent research has focused on regulation and its reform.[71] Phased deregulation of wellhead prices began in 1978, yet field markets still show few signs of a balance between supply and demand. Some researchers have attempted to measure the effects of price regulation; others have offered proposals for regulatory reform. Maintained throughout much of this literature is the assumption that the use of long-term contracts is an obstacle to economic efficiency.

For example, regulation is blamed for the problem associated with large take-or-pay requirements in contracts negotiated just prior to the onset of deregulation. That contracts are long-term is blamed for the problem's persistence. Many policy proposals have attempted to force changes in contracting practices, either by abrogating existing contracts or directing all parties to recontract. Others suggest changes in the institutional structure of the industry, thereby reducing the need for long-term contracts. It is often argued, for example, a switch from private to common carriage would allow spot markets and short-term marketing arrangements to displace long-term contracts. We have noted in this article the widespread use of long-term contracts prior to the advent of binding wellhead price regulation and have argued that such contracts were effective at coordinating production and exchange in the presence of potential opportunistic behavior.

Two differences between the provisions in the contracts we studied and more recent marketing arrangements are important. First, recent contracts generally provide for downward price and quantity adjustments when demand falls. Second, recent arrangements are of much shorter duration than their early postwar counterparts, and they typically feature escape clauses allowing either the pipeline or the producer to terminate the agreement. Otherwise, provisions in recent agreements closely resem-

[71] See the review in Braeutigam & Hubbard, *supra* note 22.

ble provisions in older contracts. Contracts from the 1950s did not need to incorporate the downward price flexibility observed in recent marketing arrangements since natural gas prices were rising rapidly in real terms. Had such flexibility been needed, there is no reason a priori to suppose that it could not have been generated.

The much shorter duration of recent contracts arises from current supply conditions in the industry. Low market prices have reduced new exploration, and take-or-pay provisions have made it difficult for pipelines to substitute cheaper gas from new sources for more expensive gas covered in existing contracts. Much of the contracting in recent years has, in fact, been recontracting. In some cases, the original long-term contracts have expired, and the relationship is maintained using short-term arrangements or spot-market transaction. In other cases, short-term exchange replaces long-term contracts on a temporary basis; if the arrangement is terminated for any reason, the relationship reverts back to an existing long-term contract.[72] That is, these short-term contracts are used by producers and pipelines that are already hooked up. No substantial new specific capital is involved. To the extent that specific investments are the primary motive for long-term contracts in these markets, the shorter length of recent agreements is not surprising.

Our analysis suggests that, as new relationships are begun, private carriage will once again entail long-term contracting. Gathering lines will be needed to connect pipelines with new producers, and the capital involved will be both long-lived and specific. Producers will be reluctant to make the investments in these lines unless they are assured of long-term access to pipeline capacity. Pipelines will likely refuse to make these investments unless producers are willing to commit their reserves on a long-term basis. Short-term contracts cannot provide these assurances.

This focus on the efficiency role of long-term contracts has important policy implications. If pipelines continue to operate as private carriers, long-term contracting will likely reemerge as an important means of organized exchange, along with short-term marketing agreements and spot-market transactions. Our research indicates that, during the 1950s, long-term contracts served to allocate resources efficiently, while mitigating the potential for opportunistic behavior. Although these older contracts contained few mechanisms for downward price and quantity adjustments, there is no reason that they could not have done so if there had been a need. Future long-term contracts will likely contain such mechanisms.

[72] O'Neill and Burke provide a detailed account of the problems facing the industry in the mid-1980s, including those problems associated with short-term contracting. Richard P. O'Neill & David A. Burke, Natural Gas Wellhead Markets: Past, Present, and Future, Natural Gas Monthly, DOE/EIA Publication No. A-0130 (1985).

APPENDIX

TABLE A1

CONSTRUCTION OF NATURAL GAS MARKETS AND REGIONS

	DEFINITIONS			
MARKET	Federal Power Commission	MacAvoy (1962)	As Used Here	AREAS INCLUDED
1. Mississippi	Gulf Coast	Gulf Coast	Omitted	Forrest, Hancock, Jasper, Jefferson Davis, Jones, Lamar, Pearl River, and Simpson counties
2. South Louisiana	Gulf Coast	Gulf Coast	Gulf Coast	Arcadia, Allen, Assumption, Beauregard, Calcasieu, Cameron, Iberia, Jefferson, Jefferson Davis, Lafayette, Lefourche, Placquemines, Rapides, Saint Charles, Saint Landry, Saint Mary, and Terrebonne parishes*
3. Houston	Gulf Coast	Gulf Coast	Gulf Coast	Bee, DeWitt, Frio, Goliad, Jackson, Karnes, La Salle, Lavaca, Live Oak, McMullen, Refugio, and Victoria counties
4. Goliad	Gulf Coast	Gulf Coast	Gulf Coast	Austin, Brazoria, Chambers, Colorado, Fort Bend, Galveston, Hardin, Harris, Jasper, Jefferson Liberty, Matagorda, Montgomery, Newton, Orange, Polk, San Jacinto, and Wharton counties
5. Corpus Christi	Gulf Coast	Gulf Coast	Gulf Coast	Brooks, Duvall, Hidalgo, Jim Wells, Kleberg, Nueces, San Patricio, Starr, and Willacy counties

6. North Louisiana/ East Texas	Midcontinent	Gulf Coast	Gulf Coast	In Louisiana: Bienville, Bossier, Caddo, Claiborne, De Soto, East Carroll, Lincoln, Madison, Ouachita, Webster, and West Carroll parishes;† in Texas: Cass, Gregg, Harison, Marion, Panola, Rusk, Shelby, Smith, and Wood counties; in Arkansas: Miller County
7. North Texas/ Oklahoma	Midcontinent	Midcontinent	Midcontinent	All counties in Oklahoma except Beaver, Cimarron, and Texas counties and the Hugoton area and vicinity; all counties in North Texas; in Arkansas: Crawford, Franklin, and Sebastian counties
8. Kansas	Midcontinent	Midcontinent	Midcontinent	All counties except Finney, Grant, Gray, Hamilton, Haskell, Kearney, Meade, Morton, Seward, Stanton, and Stevens
9. Hugoton/ Panhandle	Midcontinent	Midcontinent	Midcontinent	In Colorado: Baco County; in Kansas: Finney, Grant, Hamilton, Haskell, Kearney, Meade, Morton, Seward, Stanton, and Stevens counties; in Oklahoma: Beaver, Cimarron, and Texas counties; in Texas: Carson, Gray, Hansford, Hutchinson, Moore, Ochiltree, Potter, Roberts, and Sherman counties
10. West Texas/ Southeast New Mexico	Midcontinent	Rocky Mountains	Rocky Mountains	In New Mexico: Lea County; in Texas: the western portion, excluding the Panhandle area
11. Rocky Mountains	Rocky Mountains		Omits all but a portion	All counties in the "Four Corners" area of New Mexico, Colorado, Utah, and Arizona; in Nebraska: Cheyenne, Deuel, and Kimball counties

* All counties south of 31 degrees north latitude, including offshore contracts.
† All counties north of 31 degrees north latitude.