NATURAL GAS MARKETS AND CONTRACTS
R. Golombek, M. Hoel and J. Vislie (editors)

Natural Gas Contracting in Practice: Evidence from the United States*

by

R. Glenn Hubbard
Northwestern University and the
National Bureau of Economic Research

and

Robert J. Weiner
ICF Incorporated and Harvard University

1. Introduction

The design of long-term contracts for the sale of natural gas is a problem that is both important and difficult. It is *important* because a single contract can specify the commercial terms under which substantial reserves are sold over an extended period of time. Slight variations in contract design have the potential to make a large difference in revenues received. While contracts can be (and sometimes are) abrogated when conditions change, doing so is likely to be costly and detrimental to the abrogator's reputation as a reliable supplier or purchaser, resulting in worse terms in future negotiations.

Designing the optimal contract is *difficult* for three reasons. First is uncertainty over future market conditions, particularly the level and elasticity of demand, and the extent of interfuel competition. Second is the

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small number of competing buyers and sellers in the natural gas market. Bilateral oligopoly raises the prospect of strategic behavior on both sides. Third is the very complexity of the contract itself. On the one hand, no contract is complex enough to foresee all possible contingencies and specify terms for each. Thus, the prospect of *opportunistic* behavior by one's contracting partner — in other words, the taking advantage of circumstances unforeseen in the contract — must be protected against. On the other hand, contracts in force are already so complex — with various interacting price and non-price provisions — that existing economic optimization models are inadequate to deal with them.

Given the importance and difficulty of contract design, a surprisingly small amount of systematic quantitative research has been undertaken on the problem. There are at least three approaches to the problem that are both interesting and yield potentially fruitful results. Further advancements in theoretical optimization models could result in specification of contract provisions under various assumptions about environment and strategic behavior. Simpler, but perhaps more robust, simulation models can be developed to evaluate seller strategies under various scenarios. Analysis of actual contracts can shed light on factors that influence the outcome of contract negotiations, and provide insight into contractual performance.

The small literature on natural gas contracting is concerned primarily with the first approach, as exemplified by work at the Department of Economics at the University of Oslo, and the second, as exemplified by work at the Christian Michelsen Institute. The approach of this paper, in contrast, is empirical.

The paper examines contracts for the sale of wellhead natural gas in the United States in the era before price regulation. The motivations for examining these contracts are three. First, the bulk of U.S. natural gas production is now largely free of price controls, for the first time in a quarter century. Pricing behavior in an unregulated environment is an important question for public policy, since claims of anticompetitive behavior provided the rationale for controls, as well as an interesting problem in industrial organization. Although prices on new contracts are roughly five times in real terms what they were in 1960, the structure of the market is similar. Pricing is the outcome of bilateral negotiations; there is no organized marketplace, nor any "market price".

Second, from the standpoint of economists interested in natural gas trade, the 1950s offer a rich sample of contracts and contractual provisions, which can serve to stimulate intuition. The contracts exhibit the features characteristic of the gas industry — long term-length, favored-nation clauses, take-or-pay, etc. Theories of gas trading behavior should be testable with these data.

Third, from the standpoint of industrial organization, the data set we have assembled provides a rare opportunity. Structural information (identities of buyers and sellers, cost characteristics) and behaviorial information (price and non-price contract provisions) is available for every transaction in the market. Thus we can exploit data to test hypotheses suggested by the Williamsonian [1975] "transactions-cost" approach to industrial organization. The Williamsonian approach departed 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, which had previously been viewed with suspicion as anticompetitive, was explained as an efficient response to small numbers bargaining problems. When a transaction entails one of the parties' 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 as efficient responses to this so-called "hold-up" problem, rather than as monopolistic behavior (Mitchell [1976]). The two are hardly mutually exclusive, however, but no attempts have been made to disentangle them.

A fundamental problem with the Williamsonian approach is that although it suggests some testable hypotheses, the necessary data on individual transactions are almost never publicly available. The only empirical work in the area has required laborious surveys or extraction of provisions from individual contracts (Goldberg and Erickson [1982], Monteverde and Teece [1982], Joskow [1985]). The natural gas industry provides an ideal laboratory for examination of Williamsonian and monopolistic behavior because of the relatively small number of buyers and sellers in each market, and because of the specific up-front capital investments required on the part of both sellers, in the form of natural gas wells, and buyers, in the form of pipeline connections.[1]

The paper is organized as follows. Section 2 provides institutional background on the U.S. natural gas industry and a discussion of the data used. We develop a simple model of producer-pipeline contracting in Section 3. The model specifies an efficient contract involving both a fixed payment and flexible marginal compensation. The two issues we stress in

[1] Our focus is on transactions between wellhead producers and pipelines, though some of the forms of contractual provisions carry over to other segments of the industry as well (Kalt [1985]).

light of potential horizontal and vertical market failures (by structure or imperfect information) are bargaining over the size of the inframarginal payment, and the way in which efficient marginal compensation might be enforced once the contract is signed. That is, in addition to negotiations over initial price, producers and pipelines bargain over non-price contract provisions which serve to mitigate the Williamsonian "hold-up" problem.

Our approach offers two important extensions of contracting models in industrial organization. First, given the richness of the data we use — with both market and transaction detail — we can test the relative importance of "market power" and "Williamsonian" influences in contract negotiation. Second, we can test the extent to which non-price provisions serve an efficiency role in the contracting process or whether they are just instruments of non-price competition.

Our principal empirical findings in Section 4 are two. First, we find some evidence of monopsony power in determining initial contract prices, though Williamsonian variables reflecting buyer and seller size (both absolutely and within particular markets) are also important. Second, use of non-price provisions does not reflect producer market power, nor do these provisions have a particular "shadow price" in producer-pipeline contracts. Rather, the provisions are best explained as designed to mitigate problems of informational asymmetry between pipelines and producers, and to ensure flexible marginal compensation in periods of growing demand.

Some conclusions and implications are discussed in Section 5. Details about the construction of the variables used in the study appear in the Appendix.

2. The U.S. wellhead natural gas industry

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, Middle West, and West. The Natural Gas Act of 1938 authorized the Federal Power Commission (FPC) to regulate interstate pipeline tariffs, but wellhead prices (the prices charged by producers to pipelines) remained uncontrolled.[2] The Supreme Court extended the FPC's jurisdiction to wellhead prices in the *Phillips* case in 1954. The decision was based in large

[2] Discussions of natural gas regulation can be found in Braeutigam and Hubbard [1986] and Vietor [1984].

part on the alleged monopoly power of Phillips Petroleum, the largest of the more than 2,000 independent[3] 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 (Vietor [1984]).

As a result of the *Phillips* decision, the FPC froze wellhead prices in 1954, and required producers to file rate schedules[4] 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[5] (Vietor [1984]). 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 (Braeutigam and Hubbard [1986]).

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 database 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 regulatory methods) following the *Phillips* decision.[6]

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 (i) contracts for gas not dedicated to interstate commerce (since intrastate pipelines were outside FPC jurisdiction),[7] (ii) short-term contracts (with a duration

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

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

[5] The FPC declined to review initial prices on new contracts (MacAvoy [1962, p253]). 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 (Lindahl [1956]). Most of these were later approved.

[6] *Champlin Oil and Refining Co., et al.*, Federal Power Commission Docket G–9277, 1957–59, Exhibit 4–LC.

[7] MacAvoy [1962, p29]) estimates that 70– 80 percent of gas in contracts signed during this period was sold in interstate commerce.

of less than twenty years), (iii) 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 (iv) contracts signed, but not yet filed, by September 1, 1957.

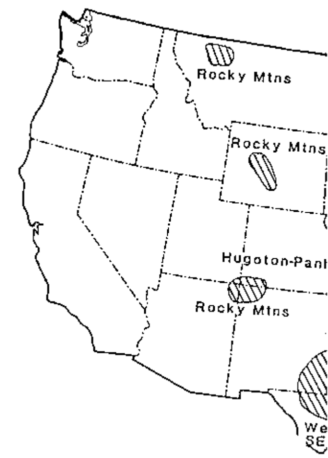
Associated with each transaction is the following information: pipeline, producer, date, location (state, county, and gas field), term length, price adjustment clause, initial price, price on June 30, 1957 (only three contracts in the database were filed after this date), and volume in 1956 (for contracts 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 (e.g., individual producer-owners who appeared to be from the same family were aggregated).

Thus we have 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, Mid-Continent, and Rocky Mountains. The FPC divided the Gulf Coast region into five markets, which from east to west are: Mississippi, Southern Louisiana, Houston, Goliad, and Corpus Christi. The Mid-Continent region was likewise divided into five markets — North Louisiana/East Texas, Hugoton-Panhandle, North Texas/Oklahoma, Kansas, and West Texas/Southeast New Mexico. Figure 1 shows the rough geographical extent of these markets.

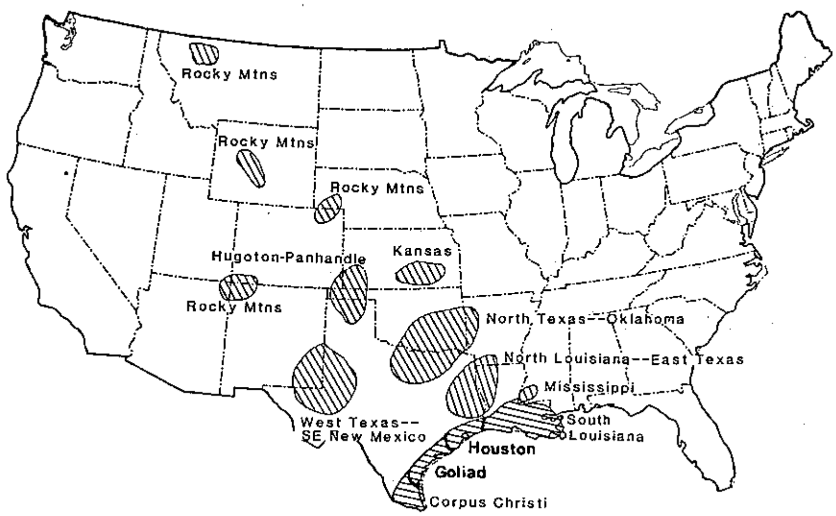
In his pioneering study of price formation in natural gas fields, MacAvoy [1962] reclassified the North Louisiana/East Texas and West Texas/Southwest New Mexico markets on the basis of the destination of the gas produced there. Roughly speaking, Gulf Coast supplies went to the East, Mid-Continent supplies to the Midwest, and Rocky Mountain supplies to the West. Market definition is discussed in detail by MacAvoy; we follow his classification here (the Appendix provides a list of counties in each market). Of course, the definition of a market must be based on economic as well as geologic considerations. We discuss this issue later in the context of empirical work.

3. Long-term contracting as a bargaining problem

To motivate our tests of market power and Williamsonian influences on contract bargaining, we develop a simple model of pipeline-producer contracting, wherein both price and non-price provisions are used. A bargaining



U.S NATURAL GAS MARKETS



problem is generated by the issues of distribution of inframarginal rents and payment of marginal compensation. Unlike other natural resource markets (e.g., the oil market), which tend to be characterized by both spot and contract trades, natural gas sales have occurred overwhelmingly under long-term contracts. Other commodity markets lack the fundamentally bilateral relationship at the producer level, since buyers and sellers are not linked by immobile capital.

Many factors may motivate long-term contracting. 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 organization through spot exchange is prone to frequent and costly renegotiation (Williamson [1975]). In the natural gas industry, the wellhead producer and pipeline face this problem. In addition, once the initial gas well development costs are sunk, a pipeline faces the temptation to appropriate some of the rents from production unless the producer has an alternative means of sale (see the discussion of "quasi-rents" in Klein, Crawford and Alchian, [1978]). 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.

Our basic framework drawn on implicit contracting models (see Hall and Lilien [1979], Hubbard and Weiner [1984], [1986]). Pipeline technology, rolled-in pricing,[8] 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 $B(Q,t)$ 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,[9] maximizing expected profits, given by:

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

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

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

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

8 "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.

9 Adding risk aversion does not qualitatively change the results presented here (Green and Kahn [1983]).

Equation (3) implicitly defines $B(\alpha, \beta, Q^*(\alpha, \beta))$, the set of efficient payment rules. 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. Moral hazard problems surface as well with respect to final pipeline demand, since there is no incentive for the pipeline to reveal the value of the gas.

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, but not its level. 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 (Hall and Lilien [1979]).

An efficient output-contingent contract exists in the special case wherein both demand and opportunity cost shocks occur, but are related; i.e., $\beta = f(a)$. 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. An efficient contract satisfies the conditions;

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

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

Let $\alpha(Q)$ represent the value of the demand shock for which Q is the efficient output level (i.e., 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 $\overline{B}$ encompasses inframarginal payments.

While this model is simple and highly stylized, it is sufficient to yield the important result (6) — efficient contracts under demand uncertainty and bilateral monopoly are characterized by a fixed payment which is unrelated to cost conditions, and a flexible payment that covers marginal costs. It is this result that motivates our empirical work. Viewing the fixed payment as a quasi-rent, we attempt to explain its distribution between the contracting parties in terms of market power. We treat the flexible payment somewhat differently, testing the Williamsonian efficiency hypothesis against the alternative that it too reflects market power.

In the gas market, the fixed payment comes about 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. Take-or-pay percentages varied little across contracts in quantity terms (see MacAvoy [1962]), though the *initial price* set in the contract will in general differ across contracts depending on the relative bargaining positions of the transacting parties. It is this bargaining that we model below with respect to initial contract prices. Contemporary accounts (e.g., MacAvoy [1962]) emphasized the importance of differences in market power (specifically pipeline monopsony power) in the bargaining process. Our approach will enable us to distinguish between market power and Williamsonian influences.

Of course, what is needed to ensure efficiency on the margin is 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 Williamsonian opportunism, there is no reason to believe that pipelines will represent downstream demand correctly in providing marginal compensation to producers. In addition, nothing would guarantee increases in real prices in response to growth in demand.

One clause providing some protection agains this type of opportunistic behavior is the two-party *most favored nation clause* (MFN), 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.

For our purposes in examining the contracting bargain, the MFN provision has substantial informational value. First, by putting a clause in the contract, the seller could mitigate the problem of being out-negotiated for a lack of knowledge about current or future demand and prices. This information would be most needed by small producers. Small producers lack the resources to prepare elaborate forecasts of downstream demand.

In addition, since large producers are more likely to operate in several field markets than small producers, pipelines are less likely to deny fair marginal compensation to them for fear of being denied access to gas in the future or in other markets. Second, 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 conditions warrant payment of prevailing field prices.

Our interpretation of the MFN as an instrument to replicate efficient contracting under imperfect information 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. Moreover, it is inappropriate to think of the MFN as just a means of non-price competition. Studies of regulated industries have emphasized the importance of non-price competition (White [1972]; Hubbard and Weiner [1984], [1986]), but wellhead price ceilings were not binding during our period of study. Calculating the "shadow price" of an MFN by, say, including a dichotomous variable for the clause in a price regression would be misleading. 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.[10]

4. Empirical tests of market power and Williamsonian influences on contract determination

Based on our results in (6) and our discussion above, we divide our empirical efforts into two parts — considerations of the determination of initial contract prices and the use of the most-favored-nation clause. In so doing, we can distinguish between the predictions of "market power" and "transactional" models. That is, our approach is to define variables associated with market structure, Williamsonian "hold-up" problems, and costs, and to investigate their impact on contract provisions.

Market structure is of interest because allegations of producer monopoly power were instrumental in the decision to regulate wellhead prices, as

[10] Loosely speaking, "mature" refers to markets wherein uncertainty over future discoveries is relatively small due to well-established geological knowledge, due to e.g., extensive drilling. During the 1950s, markets most closely fitting this description were the more easterly Gulf Coast, Hugoton/Panhandle, and West Texas/New Mexico.

Market	Vol. (MMCF/year)	Avg. Price	Seller Concentration			Buyer Concentration		
	(No. of contracts)	Price (¢/mcf)	C4	Herfindahl	No.	C2	Herfindahl	No.
1 Mississippi	31,783 (68)	19.47	.81	.20	46	1.00	.94	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	.70	.30	6
4 Houston	46,584 (169)	10.13	.32	.07	89	.77	.39	6
5 Corpus Christi	156,610 (160)	11.08	.47	.12	73	.78	.31	5
6 North Louisiana/ East Texas	200,111 (221)	10.68	.49	.20	95	.69	.37	8
7 North Texas/ Oklahoma	116,730 (223)	9.78	.61	.12	81	.75	.27	7
8 Kansas	38,374 (98)	12.57	.52	.07	48	.45	.81	5
9 Hugoton/ Panhandle	131,242 (354)	13.33	.59	.12	100	.65	.31	7
10 West Texas/ New Mexico	66,840 (105)	9.95	.65	.12	56	1.00	.85	2
11 Rocky Mountains	39,149 (99)	7.49	.70	.10	45	.60	.24	7
					579			33

Note: Data (except for number of contracts) refer only to contracts with recorded volumes (1563 of 1804 contracts).

Table 1: Market characteristics: concentration and pricing.

noted above. There have also been claims that pipelines have appropriated some producer rents through their exercise of monopsony power. 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 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 between parties, so that bargaining on price and non-price provisions may mitigate inefficiencies on the margin associated with monopsonistic behavior. 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 one), as well as the Herfindahl index for both buyers and sellers.[11]

The *Williamsonian "hold-up" hypothesis* is applicable to 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-monopoly negotiations. The pipeline and the well are both forms of immobile capital, and buyer and seller 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.[12] The buyers are natural gas pipelines — large companies with knowledge of downstream demand, and with a larger 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 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,

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[11] 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. The reciprocal of the Herfindahl index is equal to the number of Cournot followers if all firms were the same size.

[12] 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.

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	0.0
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 Gulf Trans.	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 Pipe.	11	12.27	.232	17,794	40.2
	Texas-Illinois	9	13.97	.079	6,024	26.2
	Texas Gas Corp.	8	12.35	.005	412	100.0
	Trunkline	1	18.00	.001	30	0.0
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

Table 2: Pipeline operations by market.

Market	Pipeline	Number of contracts	Average Price Paid (¢/MCF)	Market Share	Total Volume (MMCF)	Percentage of Buyer Total
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

	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
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	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 Trans.	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
	Southern	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
	Consol Utilities	27	10.00	.019	2,186	100.0
	Colorado	4	15.00	.000	56	0.1
	Northern	2	15.00	.000	47	0.2
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

Table 2a: Pipeline operations by market (continued).

Market	Pipeline	Number of contracts	Average Price Paid (¢/MCF)	Market Share	Total Volume (MMCF)	Percentage of Buyer Total
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
	Nat. Gas Pipe. of Amer.	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
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	0.5

Source: Federal Power Commission, Docket G-9277, Exhibit 4-LC

Table 2b: Pipeline operations by market (continued).

Firm[1]	Contracts Signed 1953–1957[2]	Contracts Signed pre-1953[3]	U.S. Rank in Natural Gas Production[4]
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

Notes: Firm name in use at the time.

1 Many of the firms have changed ownership or name; affiliated firms are in parentheses.

2 *Source: Champlin Oil and Refining Co., et al.*, FPC Docket G-9277, exhibit 4-LC. Contracts are only those in table 1.

3 *Source: ibid.*, exhibit 2-LC, table 1. All interstate contracts still in effect as of 1955 are included.

4 *Source:* American Petroleum Institute [1984], *Market Shares and Individual Company Data for U.S. Energy Markets: 1950–1983*. Discussion Paper #014R, November. Figures are for 1955.

Table 3: Ten largest contract signers (producers).

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). We 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 squeeze out all the rents from a partner they anticipate facing over and over 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.[13] We can then test whether, e.g., the Texas Company (Texaco) is able to obtain a better idea than a small producer for its gas.

Third, *transportation 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 worth less because it is further from pipelines, or because 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.

We are no more able to establish costs than was the FPC staff in the 1950s, and employ proxies — the distance of the market from consuming regions,[14] 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.

Finally, we include a couple of 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 fields in each market prevents a multicollinearity problem with the seller

[13] 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 gave similar results.

[14] We constructed this variable using FPC maps, by measuring the distance along major pipeline routes from the center of each market to reference points chosen somewhat arbitrarily. Since distances are not comparable across regions (because of e.g., varying terrain, weather, and rights of-way), we also include dummy variables for the Mid-Continent and Rocky Mountain regions. See the appendix for details.

Variable	Mean Value
Market-Structure Variables	
Seller concentration (C4)	0.51
Seller Herfindahl	0.11
Buyer concentration (C2)	0.72
Buyer Herfindahl	0.38
Williamsonian variables	
Seller market share	0.02
Buyer market share	0.29
Seller size (total volume in million cubic feet)	0.12
Buyer size (total volume in million cubic feet)	0.90
Seller size (total contracts)	14.10
Buyer size (total contracts)	134
Cost variables	
Contract volume (in million cubic feet)	0.074
Distance measure (miles)	715
Gathering-cost proxy (volume per square mile in county)	22.5
Other variables	
Common-pool proxy (sellers per field)	11.9

Table 4: Means of explanatory variables in price equation.

market-structure variable. The level of demand is also clearly important. We treat demand roughly, by employing dummy variables for each year after 1953, because a secular increase in demand caused prices to rise over the period.[15]

Table 4 shows the mean of each variable.

[15] 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.

4.1 Estimates of relative influences on contract price determination

The specification of our price equation is:

$$P_{ijkt} = \alpha + \mu M_k + \omega w_{ijk} + \Omega W_{ij} + \gamma C_{ijk} + \delta D_{kt} + \epsilon_{ijkt}, \tag{7}$$

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 Williamsonian variables specific to the market where the transaction takes place, W a vector of Williamsonian variables associated with the contracting parties, C a vector of transportation cost variables, D a vector of other variables, ε an additive disturbance, and α, μ, ω, Ω, γ, and δ are coefficients to be estimated.

In the absence of Williamsonian information asymmetries and 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 the specific contracting firms.

Equation (7) was estimated by ordinary least squares using data on contracts in markets 2–10. Market 1 (Mississippi) was omitted because no distinction is made between firm and market characteristics (i.e., complete monopsony), because there are few contracts in the market, and because most of these contracts were 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. As a result of these omissions and incomplete information in some of the contracts, 1427 contracts are used in the empirical analysis.

Table 5 reports the regression results for the contract price equation. The results in table 5 are presented for the categories of variables described before — market-structure, Williamsonian, transportation-cost, and other. Two sets of market-structure variables were used — (i) the concentration ratios on the buyer (two-firm) and seller (four-firm) sides, and (ii) the Herfindahl indices for buyers and sellers. In addition, two sets of variables were employed as measures of absolute size of buyers and sellers — (i) buyer and seller total volumes and total numbers of contracts, and (ii) buyer total volume and seller total contracts. The latter represents 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

Market-Structure Variables								
Seller concentration ratio	−0.88	(1.19)			−0.67	(0.91)		
Buyer concentration ratio	−10.03	(13.99)			−10.90	(15.70)		
Seller Herfindahl			−8.49	(5.60)			−8.94	(5.80)
Buyer Herfindahl			−2.22	(4.13)			−2.76	(5.15)
Williamsonian variables								
Seller market share	3.22	(0.71)	−0.74	(0.15)	2.36	(0.53)	−1.19	(0.25)
Buyer market share	−1.53	(4.87)	−0.39	(1.16)	−1.79	(5.75)	−0.70	(2.05)

Market-Structure Variables								
Seller concentration ratio	−0.88	(1.19)			−0.67	(0.91)		
Buyer concentration ratio	−10.03	(13.99)			−10.90	(15.70)		
Seller Herfindahl			−8.49	(5.60)			−8.94	(5.80)
Buyer Herfindahl			−2.22	(4.13)			−2.76	(5.15)
Williamsonian variables								
Seller market share	3.22	(0.71)	−0.74	(0.15)	2.36	(0.53)	−1.19	(0.25)
Buyer market share	−1.53	(4.87)	−0.39	(1.16)	−1.79	(5.75)	−0.70	(2.05)
Seller size (total volume $\times 10^{-5}$)	0.38	(0.78)	0.05	(0.10)				
Buyer size (total volume $\times 10^{-5}$)	−0.15	(0.90)	0.20	(1.12)	−0.82	(7.93)	−0.86	(7.81)
Seller size (total contracts)	0.015	(2.56)	0.018	(3.04)	0.011	(2.46)	0.018	(3.76)
Buyer size (total contracts)	−0.007	(4.85)	−0.01	(7.46)				
Cost variables								
Contract volume ($\times 10^{-5}$)	7.76	(3.38)	8.19	(3.40)	8.85	(3.98)	10.90	(4.63)
Distance measure	−0.0003	(0.51)	−0.002	(3.20)	−0.0006	(1.04)	−0.003	(4.51)
Midcontinent dummy	−0.20	(1.09)	−0.21	(1.17)	−0.28	(1.50)	−0.26	(1.45)
Rocky Mountain dummy	−0.18	(0.43)	−2.57	(6.08)	−0.05	(0.11)	−2.39	(5.58)
Gathering-cost proxy (volume per square mile in county)	−0.003	(1.64)	−0.004	(1.82)	−0.003	(1.84)	−0.004	(2.10)
Other variables								
Constant term	19.25	(26.56)	15.06	(28.94)	19.53	(26.83)	15.15	(28.59)
Common-pool proxy (Sellers per field)	−0.02	(4.13)	−0.01	(1.97)	−0.02	(4.50)	−0.02	(4.50)
1954 dummy	−0.18	(1.00)	−0.17	(0.87)	−0.08	(0.45)	−0.013	(0.07)
1955 dummy	1.38	(7.42)	1.29	(6.58)	1.51	(8.11)	1.47	(7.43)
1956 dummy	2.62	(14.99)	2.49	(13.53)	2.71	(15.53)	2.63	(14.08)
1957 dummy	2.93	(13.75)	2.97	(13.23)	3.07	(14.42)	3.19	(14.11)

* *Note:* Absolute values of t-statistics are in parentheses.

Table 5: Price determination in producer-pipeline contracts.

Summary Statistics				
N	1427	1427	1427	1427
$\overline{R}^2$	0.41	0.35	0.40	0.32
F	55.90	43.47	60.42	43.76
F-Tests for Exclusion (Significance levels)				
Seller and buyer concentration	.0001	.0001	.0001	.0001
Seller and buyer market shares	.0001	.4147	.0001	.0001
Seller and buyer size (total volume)	.5814	.5140		
Seller and buyer size (total contracts)	.0003	.0002		
Seller and buyer size (volume and contracts)	.0001	.0001		
All Williamsonian variables	.0001	.0001	.0001	.0001

Table 5a: Price determination in producer-pipeline contracts (continued).

information about market conditions, are indexed for size by their total volume.

The coefficients on buyer and seller concentration 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.[16] These results are consistent with much of the discussion of the gas market by economists in the 1950s — that such anticompetitive problems that might exist were most likely to come from the buyer, not the seller side. The Herfindahl measures yield similar results.

The coefficient estimates in table 5 are quite supportive of the "Williamsonian" view of contracting and price setting. Measures of buyer and seller size in the market have the expected sign, though only the buyer market share coefficient is precisely estimated. 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.[17] Increases in the number of producer contracts raises the contract price, while the opposite is true for buyers (pipelines). In general, the Williamsonian variables are relatively more important on the seller side than the buyer side, where market-power effects dominate. For example, a producer with 100 contracts would receive about 1.5 cents per mcf more than a producer with just one contract.

Finally, on the transportation cost side, the distance and gathering-cost proxies were imprecisely estimated. The positive coefficient on the contract volume reflects the significance of the fixed cost of connecting the individual well to the pipeline. The negative and statistically significant coefficient on the number of sellers per field indicates the importance of the common-pool problem. Finally, apart from other conditions, dummy variables for years indicate generally a rising profile of prices over the period.

The results in table 5 are indicative of the importance of "small-numbers bargaining" issues in the gas market. Based on the F-tests re-

[16] Indeed, we obtain a negative coefficient on the seller-concentration variable. Part of this seeming anomaly is traceable to the appearance of many "oil-well gas" contracts (produced jointly with oil — at a lower marginal cost — in market 7, which is highly concentrated). Dropping these contracts produces a positive but statistically insignificant coefficient on producer concentration. When we complete the process of matching our data sets, we will be able to segregate systematically the "oil-well gas" contracts. We make no ad hoc adjustments here.

[17] This is probably more important for producers than for pipeline companies, which have better information about downstream demand conditions. Indeed, if we include only producer volume and buyer total contracts, the same pattern emerges.

ported in the table, we can reject at any reasonable significance level the hypotheses that the (i) market-share variables, (ii) numbers of buyer and seller contracts, (iii) combination of volumes and numbers of contracts, and (iv) combination of volumes, numbers of contracts, and market shares should not be included in the contract price equation. We cannot reject the joint inclusion of buyer and seller concentration ratios, though only the former is individually consistent with the market-power hypothesis.

4.2 Estimates of relative influences on MFN use

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.[18] During the 1950s, concern over MFNs was based on their supposed origins in *producer* market power. If producer market power were important, there is no reason it should have appeared in the form of MFNs rather than higher initial prices or take-or-pay requirements. In addition, the MFN is activated at the discretion of the buyer.

Table 6 illustrates the use of most-favored-nation clauses in the various field markets. As the table makes clear, the MFN was not universally used, and its use differed considerably across markets; the clause must not be without its disadvantages. One potential cost of the MFN stems from the obvious "free-rider" problem. Resources may be wasted as pipelines switch fields to avoid triggering MFNs. Both Neuner [1960] and MacAvoy [1962] stressed the importance of this problem.[19] The potential for opportunistic field switching suggests the possibility that buyers (pipelines) with large market shares are more likely to agree to MFNs, since switching would depress prices and raise the price of alternative supplies.

We test the extent to which the MFN provision serves the Williamsonian function of ensuring efficient contracting, using a probit model due to its dichotomous character. In so doing, we can distinguish whether the MFN is part of an efficient contracting arrangement, as suggested by the model in Section 3, or is the result of monopoly power exercised by producers. The latter view implicitly considers the MFN to be solely a component of the transaction price.

[18] This is true under a "two-party" MFN clause. There are also a few "three-party" MFNs whereunder 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.

[19] See *Hearings on HR4560, Exemption of Gas Producers*, Part I and II [1955], and the discussion in Neuner [1960].

Market	Fraction of Contracts Covered by MFN
1 Mississippi	0.0%
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	0.8
10 West Texas/New Mexico	46.7
11 Rocky Mountains	33.8
All markets	51.9

Table 6: Use of Most-Favored-Nation Provision.

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). In addition, we include a "buyer escape" variable measuring the fraction of a pipeline's total volume accounted for outside the market where the contract is signed. The expected sign on this variable is ambiguous. A higher value of "buyer escape" makes the pipeline more willing, *ceteris paribus*, to grant an MFN; on the other hand, higher values of "buyer escape" make the potential for field switching greater, making the clause of smaller value to producers.

That is, we estimate a probit model of the form:

$$MFN_{ijk} = f(M_k, w_{ijk}, W_{ij}, X_{ik}), \tag{8}$$

where X denotes the "buyer escape" described above and MFN takes on the value of 1 when a two-party MFN is used in the contract, and 0 otherwise. Other variables are as defined before in the price model.

Specific tests are formulated as follows. A market-power interpreta-

Market-Structure Variables				
Seller concentration ratio	−1.21	(1.22)		
Buyer concentration ratio	−0.49	(0.87)		
Seller Herfindahl			−3.67	(3.57)
Buyer Herfindahl			1.33	(3.02)
Williamsonian variables				
Seller market share	−1.59	(0.51)	−2.12	(0.67)
Buyer market share	2.86	(8.62)	−3.24	(8.91)
Seller size (total volume)	−0.20	(2.57)	−0.10	(2.28)
Buyer size (total volume)	1.00	(7.79)	1.03	(7.64)
Seller size (total contracts)	−0.01	(1.99)	−0.01	(2.15)
Buyer size (total contracts)	0.001	(0.21)	−0.0001	(0.05)
Other variables				
Buyer escape	−0.50	(2.51)	−0.31	(1.61)
Midcontinent dummy	−1.19	(11.38)	−1.27	(11.49)
Rocky Mountain dummy	−0.90	(3.56)	−0.53	(1.93)
Constant term	5.10	(11.43)	4.89	(25.23)
Summary Statistics				
N	1375		1375	
χ^2	1618.72		1458.01	

* *Note:* Absolute values of t-statistics are in parentheses.

Table 7: Determinants of use of Most-Favored-Nation Clause.

tion of the occurrence of MFNs would imply a positive effect of producer concentration and a negative effect of pipeline concentration. In contrast, the efficient-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, wherein support for the efficient-contracting approach is striking. 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. Coefficients on buyer and seller "size" have the expected sign and are statistically significant in most cases; in particular the coefficient on seller size measured either by number of contracts or total volume is negative and precisely estimated. Large buyer market shares are positively associated with the use of MFNs, again inconsistent with the notion that an MFN is merely a component of price. This finding is complemented by the estimated negative coefficient on "buyer escape," suggesting that the field-switching problem may have been important empirically. The Rocky Mountain and Midcontinent dummies have the expected negative signs, reflecting the more infrequent use of MFNs in those regions.

Again, the results are supportive of the idea that the MFN is part of a contractual package designed to approximate marginal efficiency (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 approach and findings point up the need to consider product-market contractual provisions severally, and not focus individually on "price" and "non-price" competition. Moreover, arrangements appearing anticompetitive ex post may be part of an efficient arrangement ex ante. Policy proposals to restrict the use of particular provisions are likely to be inappropriate.[20]

4.3 Comparison with other studies

Despite the intense political controversy (Vietor [1984]), economic interest (Lindahl [1956]; Kahn [1960]; Neuner [1960]), and data gathering and compilation at the time of price control, there 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 (Kahn [1960]). Under this definition, markets could no longer be characterized as unconcentrated, as seen in table 1.

[20] This point is discussed in the context of current policy debates over the take-or-pay provision in Hubbard and Weiner [1984], [1986]). MFN provisions were restricted as anticompetitive in the 1960s.

Two studies actually looked at pricing. MacAvoy [1962] conducted a detailed investigation of structure and conduct in various markets, and carried out the only econometric analysis. He ran 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 [1960] used descriptive summary statistics on a smaller set of contracts to look for evidence of monopoly power. He did not find any.

The *Champlin* data were used to look for evidence of the Williamsonian hypothesis by Mulherin [1984]. He related several non-price contractual provisions (e.g., delivery point, minimum-purchase requirement, most-favored-nation clause), to the number of producers and pipelines in a given field, hypothesizing that the greater the number of sellers relative to the number of buyers, the greater would be the opportunity of an individual pipeline to appropriate an individual producer's quasi-rents, implying that the producer would be more likely to request these non-price provisions. Mulherin found support for the hypothesis, but did not utilize any firm-specific or cost information, making it difficult to separate it from the market-power hypothesis.

5. Conclusions and extensions

It is well recognized by economists that long-term contracting under an array of price and non-price 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, because the necessary data on individual transactions are seldom publicly available. The U.S. natural gas industry is well-suited for such tests both because of 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 paper, 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, our principal results are two. First, market-power influences are not the primary factors in contract price determination. While there is some evidence of pipeline monopsony power, there is no evidence for positive impacts of producer 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.

Use of the most-favored-nation clause 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 3. Viewed in this light, the clause is not really an instrument of non-price competition; its shadow price is both transaction-specific and market-specific.

These findings are indicative of the importance of considering small-numbers-bargaining issues in contractual negotiation. To extend the approach suggested here, data from this and other markets can be used to study other contractual provisions, including definite price escalators, renegotiation clauses, and minimum-purchase requirements.

Appendix

Construction of distance measure and regional dummies

An explanation for the inclusion of the regional dummies is as follows. Consider the following regression format:

$$P_j = \alpha + \beta_1 x_{1j} + \beta_2 x_{2j} + \cdots + \beta_d \cdot \text{Distance}_j + \varepsilon_j,$$

where P and j denote the price and contract, respectively; x's represent right-hand side variables, and distance represents distance to downstream markets. Let

$$\text{Distance}_j = D_r + D_j = D_g + (D_r - D_g) + D_j,$$

where D_r is the "base" distance from the region to downstream markets and D_j is the market-specific distance. That is,

$$D_r = \begin{cases} D_g & \text{if the contract is in the Gulf Coast region} \\ D_m & \text{if the contract is in the Midcontinent region} \\ D_{r_m} & \text{if the contract is in the Rocky Mountain region.} \end{cases}$$

For the Gulf Coast region (markets 1–6), we chose a point northeast of Nashville on the Tennessee-Kentucky border. Several arteries of the Tennessee Pipeline Company's network intersect there. For the Midcontinent region (markets 7–9), the reference point was Chicago, the largest downstream market in the area. For the Rocky Mountain region, distance was measured from the center of the market to the Arizona border.
Substituting,

$$P_1 = (\alpha + \beta_d D_g) + \beta_1 x_{ij} + \cdots + \beta_d(D_r - D_g) + \beta_d D_j + \varepsilon_j \,.$$

The market-specific distance can be measured, but the base distance for each region cannot. This problem can be surmounted by making the following substitution of dummy variables for the Midcontinent (M) and Rocky Mountain (RM) regions:

$$B_d(D_r - D_g) = \gamma_m M + \gamma_{rm} RM,$$

where the dummies assume a value of one if the contract is in the appropriate region, and zero otherwise. γ_m and γ_{rm} are coefficients to be estimated. Then the price effect is measured by

$$\beta_d(D_r - D_g) = \begin{cases} 0 & \text{if the contract is in the Gulf Coast region} \\ \gamma_m & \text{if the contract is in the Midcontinent region} \\ \gamma_{rm} & \text{if the contract is in the Rocky Mountain region.} \end{cases}$$

Market	Definitions			Counties Included
	FPC	MacAvoy [1962]	As Used Here	
1 Misssissippi	Gulf Coast	Gulf Coast	omitted	Forrest, Hancock, Jasper, Jefferson Davis, Jones, Lamar, Pearl River, and Simpson counties
2 South Lousiana	Gulf Coast	Gulf Coast	Gulf Coast	Arcadia, Allen, Assumption, Beauregard, Calcasieu, Cameron, Iberia, Jefferson, Jefferson Davis, Lafayette, Lafourche, Plaquemines, Rapieds, St. Charles, St. Landry, St. Mary, and Terrebonne parishes (all parishes south of 31° North Latitude, including offshore contracts)
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.

Table A1: Construction of natural gas markets and regions

Market	Definitions			Counties Included
	FPC	MacAvoy [1962]	As Used Here	
6 North Louisiana-East Texas	Midcontinent	Gulf Coast	Gulf Coast	Bienville, Bossier, Caddo, Claiborne, De Soto, East Carroll, Lincoln, Madison, Ouachita, Webster, and West Carroll parishes in Louisiana (all parishes north of 31° North Latitude); Cass, Gregg, Harison, Marion, Panola, Rusk, Shelby, Smith, and Wood counties in Texas; and Miller County, Arkansas
7 North Texas-Oklahoma	Midcontinent	Midcontinent	Midcontinent	Except Hugoton and vicinity: all counties in Oklahoma except Beaver, Cimarron, and Texas; all counties in North Texas; and the following Arkansas counties: Crawford, Franklin, and Sebastian
8 Kansas	Midcontinent	Midcontinent	Midcontinent	All counties in Kansas except Finney, Grant, Gray, Hamilton, Haskell, Kearney, Meade, Morton, Seward, Stanton, and Stevens

Table A1: Construction of natural gas markets and regions (continued)

Table A1: Construction of natural gas markets and regions (continued)

Market	Definitions			Counties Included
	FPC	MacAvoy [1962]	As Used Here	
9 Hugoton-Panhandle	Midcontinent	Midcontinent	Midcontinent	Finney, Grant, Hamilton, Haskell, Kearney, Meade, Morton, Seward, Stanton, and Stevens counties in Kansas; Beaver, Cimarron, and Texas counties in Oklahoma; Carson, Gray, Hansford, Hutchinson, Moore, Ochiltree, Potter, Roberts, and Sherman counties in Texas; and Baca County, Colorado
10 West Texas-Southeast New Mexico	Midcontinent	Rocky Mountains	Rocky Mountains	The western portion of Texas, excluding the Panhandle area, and Lea County, New Mexico.
11 Rocky Mountains	Rocky Mountains	omits all but a portion	omitted	All counties in the "Four Corners" area of New Mexico, Colorado, Utah and Arizona; Cheyenne, Deuel, and Kimball counties in Nebraska; Wyoming, and Montana

Table A1: Construction of natural gas markets and regions (continued).

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