Efficient Adaptation in Long-Term Contracts: Take-or-Pay Provisions for Natural Gas

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To avoid repeated bargaining in transactions supported by durable, transaction-specific investments, parties may decide to specify the terms of future trade in a long-term contract at the outset of the relationship (see, for example, Benjamin Klein, Robert Crawford, and Armen Alchian, 1978; and Oliver Williamson, 1979). A principal limitation of long-term contracting, however, is its inflexibility in the face of fluctuations in supply and demand: although contingent claims contracts permit adaptation to changing circumstances, contingent performance is costly to stipulate and even more difficult for courts to administer. To mitigate these hazards, parties will therefore wish to choose contract terms that minimize the need for costly adjudication while maintaining incentives for appropriate adaptation.

This paper examines the incidence of "take-or-pay" provisions in contracts between natural gas producers and pipelines from this perspective. Take-or-pay clauses require purchasers to pay for a contractually specified minimum quantity of output, even if delivery is not taken. The existence of such provisions and efforts by pipelines to have them abrogated in the face of declining demand during the most recent recession have generated a debate regarding the role such terms play in allocating gas resources. A common perception has been that take-or-pay provisions are an artifact of wellhead price regulation: by assuring a minimum payment, take obligations raise the expected value of a contract to a producer and thereby circumvent the effect of the price ceiling. To the extent that producers of high-cost gas were able to command higher obligations, some pipelines have been induced to purchase and sell more expensive gas to end users while leaving lower-cost supplies with smaller take requirements in the ground. The implication of this view is that take provisions are anomalies that distort market incentives and should therefore be nullified, permitting pipelines to adjust purchases in a more appropriate manner.

The problem with this explanation is that the incidence of take provisions is not limited to regulated gas supplies, but is also a feature of contracts covering unregulated pre-1954 interstate and pre-1978 intrastate gas, as well as of recently deregulated categories of new "high-cost" gas.[1] Moreover, take-or-pay clauses are also encountered in contracts for

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[1]See H. G. Broadman and M. A. Toman (1983); and M. E. Canes and D. A. Norman (1983). Take provisions were also an integral part of producer-pipeline contracts throughout the essentially unregulated period before area pricing was adopted in 1960. The *Phillips* decision in 1954 gave the Federal Power Commission jurisdiction to regulate wellhead prices of gas sold in interstate commerce. The initial regulatory efforts, however, sought to institute cost-based rates on a well-by-well basis. Using this approach, the Commission never progressed beyond regulating the parties to the original decision. The result was a prodigious case backlog. According to Paul MacAvoy and Robert Pindyck, "...The Commission itself forecast that it would not finish its 1960 case load until the year 2043" (1975, p. 13). Area rates, that effectively froze prices at the market levels of 1958–59, were an attempt to lend tractability to the regulatory process.

coal and other unregulated commodities.[2] In view of this, both H. G. Broadman and M. A. Toman, and M. E. Canes and D. A. Norman have suggested that take obligations might be a means of allocating risk between producers and pipelines. High take provisions reduce risk for producers by guaranteeing a minimum return on investments in well capacity. Unfortunately, such arguments do not provide a practical basis upon which to evaluate observed contractual arrangements without knowledge of the relative risk preferences of the parties involved.

This paper offers an interpretation of take-or-pay provisions that relies on neither risk aversion nor the existence of regulatory price ceilings. Instead, we argue that take obligations can be viewed as a mechanism for effecting appropriate incentives for contractual performance, and show that efficient breach considerations define an optimal take percentage as a function of characteristics of the transaction. These incentives are distorted, however, by the existence of regulated price ceilings, causing the adoption of take obligations *in excess* of optimal levels.[3] Whether a policy to reduce "excessive" take provisions to *ex post* optimal levels can be justified on the basis of regulatory interference depends on the regulatory environment expected to govern the development of future gas reserves.

Section I develops these arguments and applies them to contracting in the natural gas industry. Section II presents an empirical test of the model employing actual data on producer-pipeline contracts and well characteristics.

I. Performance Incentives in Long-Term Contracts

Once a transaction-specific investment has been made, only imperfect market alternatives exist and both the buyer and seller are locked into a bilateral monopoly relationship. To prevent contention over the resulting quasi rents from dissipating too large a portion of the gains from trade, the parties may try to secure a mutually advantageous distribution through a contract, the duration of which will depend in part on the durability of the associated investments. In industries with particularly durable capital, it is not uncommon to observe contractual agreements that extend for ten years or more.[4]

Over such long horizons, the need for adaptation to changing circumstances, and hence the desire for flexible arrangements, may be substantial. But a tradeoff generally exists between the flexibility provided for in a contract and the ease with which it can be implemented: a single contractual stipulation is relatively straightforward for courts to enforce in comparison to multiple contingent claims which require that both the parties and the courts establish the state that has actually transpired. The more provisions stipulated, the greater the scope for both honest misinterpretation and intentional deception, and thus the greater the likelihood of a dispute requiring costly adjudication.

To minimize these costs, the parties will wish to stipulate terms that do not require court verification of exogenous events. Accordingly, contracts usually employ unilateral options rather than contingent clauses to accommodate adaptation.[5] The goal is to

[2]As Canes and Norman note, E. M. Carney (1978) discusses the use of take-or-pay provisions in coal contracts. Similar arrangements also appear in other contracts as minimum bill provisions.

[3]Except where explicitly noted, we will be referring throughout the paper to private optimality in exchange between a buyer and a seller. The social efficiency of any contractual provision depends upon whether private valuations are distorted from social valuations by the existence of externalities or other factors. We show here that the presence of price regulation does not in and of itself justify the abrogation of take-or-pay obligations.

[4]Victor Goldberg and John Erickson, for instance, note that in their sample, "Nine of ten contracts...involving new [petroleum] cokers were for a period of at least ten years" (1982, p. 10). Coal contracts are of similar duration (Carney, p. 197). Also see below.

[5]The notion of a unilateral option is analogous to the self-selection behavior often observed in theoretical models of bargaining in an environment of asymmetric information (see, for example, Milton Harris and Robert Townsend, 1981).

design contracts in ways that reconcile the exercise of such options with joint profit-maximizing behavior.[6]

The adoption of take-or-pay provisions in long-term contracts can be usefully interpreted in this light. Fluctuations in demand or costs may make it unprofitable or even inefficient to carry out the original objectives of a contract. By altering incentives to accept or reject delivery, take provisions can induce buyers to release investments to their alternative uses only when it is efficient to do so.

A. *Natural Gas Production and Contracting*

These considerations bear directly on the organization of production and exchange in the natural gas industry. Most natural gas is purchased by pipelines from independent producers for distribution to customers in regional markets. Like oil production, the extraction of gas requires large, durable, location-specific investments in facilities and equipment. However, unlike the field market for oil which is characterized by a functioning spot market, gas sales tend to be governed by extended contracts averaging fifteen to twenty years in length. This disparity in contractual structures governing commodities that are so closely related in production technologies may be traced to differences in transmission alternatives. Whereas pipelines represent virtually the only economically feasible form of transportation for gas, oil may be transported by truck or barge as well as by pipeline, thereby reducing the extent to which oil producers are locked into a bilateral relationship.[7]

Uncertainty regarding future market conditions can make it hazardous to commit resources contractually to a particular application, however. For example, in the face of a decline in gas demand, it may become more economic to sell gas to an alternative pipeline (if the decline is regional) or to store it for future use (if the decline is economy-wide). Since uncertainty increases with the distance of the relevant horizon, the need to provide for adaptation is most acute in longer term agreements. The prevalence of take-or-pay clauses in both long-term coal and gas contracts is consistent with this reasoning. Take obligations encourage efficient adaptation by relating the payment schedule in a contract to the alternative values of the resources either in sale to alternative customers or in storage for future use.

Alternative sale values of a product in transaction-specific relationships are limited by the design and location of specialized investments. For natural gas, the most important determinant of that value is the number and proximity of alternative pipelines. The fewer the connections to pipelines, the less likely that a producer will be able to dispose of gas at a price comparable to that in the original contract. In the extreme, the sale of gas to an alternative customer may require the construction of costly new transmission facilities.[8]

[6]That joint profit-maximizing behavior does not always coincide with the private incentives of the parties to an exchange is a familiar proposition:

> ...joined as they are in an idiosyncratic condition of bilateral monopoly, both the buyer and seller are strategically situated to bargain over the disposition of any incremental gain whenever a proposal to adapt is made by the other party. Although both have a long-term interest in effecting adaptations of a joint profit-maximizing kind, each also has an interest in appropriating as much of the gain as he can on each occasion to adapt. Efficient adaptations which would otherwise be made thus result in costly haggling or even go unmentioned, lest the gains be dissipated in costly subgoal pursuit. [Williamson, p. 242]

[7]A more complete discussion of oil field markets and how they differ from those of gas is given in S. L. McDonald (1971).

[8]Alternative sale possibilities are sometimes governed by the particulars of the supply contract between a producer and a pipeline. Often, the contract governs only a portion of the well's output, which is sold to the contracting pipeline on a first refusal basis. In other cases, particularly, when the field is served by a single pipeline, the entire output of a well is "dedicated" to a particular pipeline for the life of the contract. When gas demand is low, however, pipelines have little incentive to enforce these dedication clauses. Indeed, given the present surplus, many pipelines are attempting to renegotiate their purchase obligations downward and would welcome sale to alternative buyers (see D. Norman, 1984).

Because of this, and the fact that the demand for energy resources often fluctuate on a nationwide basis, the best alternative employment for both coal and gas is often to store it for future use. Since the product can usually be left in the field, storage is generally less costly for the producer than the customer. The resource value of stored gas may be diminished, however, by the proximity of other wells: gas not extracted may be drained away by other producers operating in the same field. To attenuate the problem of competitive extraction and protect landowners from drainage, the primary gas-producing states have instituted well-spacing rules and prorationing of output among the wells in a field.[9] The prorationing formulae generally used assign each producer an interest in the field based on surface ownership and well deliverability. Gas demand is divided among the various producers by the assignment of production allowables based on each producer's interest in the field.

But such intervention, while mitigating the drainage problem, does not eliminate it. The formulae are, at best, imprecise rule-of-thumb estimates of gas location relative to surface ownership. Moreover, a production allowable conveys only the *opportunity*, not the guarantee, to produce a given amount of gas in a specified period of time. An operator who is unwilling or unable to produce his allowable faces the prospect of drainage to those who do.[10] Consequently, most gas production remains governed by the *Rule of Capture*: "Possession of the land...is not necessarily possession of the gas. If an adjoining, or even distant, owner drills on his own land, and taps your gas, so that it comes into his well and under his control, it is no longer yours, but his."[11]

In general, the desirability of reallocating resources away from their intended use depends critically on their value in alternative applications. In the case of gas, the appropriate take obligation in each instance will depend on the nature of the well and its relation to other wells, piplines, and markets.

B. *Take-or-Pay and Breach of Contract*

To illustrate these concerns, consider the relationship between a pipeline (or buyer) and producer (or seller) of natural gas, both of whom are assumed to be risk neutral. After gas has been discovered but prior to investing in production and transmission facilities, the parties write a contract specifying a capacity level and the terms under which the product is to be exchanged in subsequent periods. The value of this capacity to the pipeline depends upon such things as weather patterns, economic fluctuations, and the prices of alternate fuels, all of which are uncertain at the time the contract is written and the well drilled. If we let θ represent this uncertainty, and define

$v(\theta)=$ the value of the well to the pipeline, net of transmission costs and gross of payments to the producer; and

$y=$ the payment made by the pipeline to the producer for a contractually specified quantity of gas;

then, once θ is revealed, the pipeline and the producer would receive $v(\theta)-y$ and y, respectively—*if* the exchange takes place: for low values of θ, and hence of v, the pipeline would wish to breach the contract with the producer. Specifically, the pipeline would wish to discontinue deliveries whenever $v(\theta) < y$.[12] Were this to occur, the pipeline would

[9] Gas and oil prorationing differ in several significant respects, reflecting the greater importance of extraction rates on the amount of oil that is ultimately recoverable. For a more complete discussion, see R. E. Sullivan (1955).

[10] Both Texas and Oklahoma have attempted to ensure that producers are equally able to sell their allowables by requiring pipelines to purchase ratably (according to each producer's interest) from their suppliers in a field. However, other states do not require ratable take (Sullivan, p. 348), nor does this approach preclude disproportionate purchases by different pipelines.

[11] *Westmoreland and Cambria Natural Gas Company v. Dewitt, 130 Pa. St. 235, 18A. 724, 725* (1889).

[12] For analytical tractability, we consider a model in which gas deliveries are discontinued in a discrete fashion; i.e., the purchaser either "takes" the gas at the contract price, or else "pays" the contractually specified percentage of the full obligation and releases all of the gas contracted for to its alternative use. With a few exceptions, the continuous analog to this model in which

then earn no net return,[13] and the producer would seek the next highest value of his capacity, $s(\alpha)$, which is a function of well attributes, α.

Since efficiency requires that gas be used in its highest value, breach would in fact be efficient if $s(\alpha) > v(\theta)$. But for $s(\alpha) < v(\theta) < y$, the pipeline would wish to breach even though it would be inefficient to do so. Figure 1 depicts the ranges of $v(\theta)$ for which the buyer would wish to breach and for which breach would be efficient. In general, there is a tendency, as illustrated in the diagram, for breach to occur too frequently in unsecured agreements.

The pipeline could, however, be induced to reject delivery efficiently by imposing a penalty for nonperformance, $\delta = y - s(\alpha)$. This penalty, known as "expectation damages," is commonly employed by the courts and would normally apply to gas contracts in the absence of a stipulated take obligation.[14] If the courts always and unerringly chose this award, there would be little need to stipulate damages in the contract. But the uncertainty associated with judicial rulings encourages costly litigation. By stipulating damages, the parties avoid the costly process of determining the appropriate penalty in the

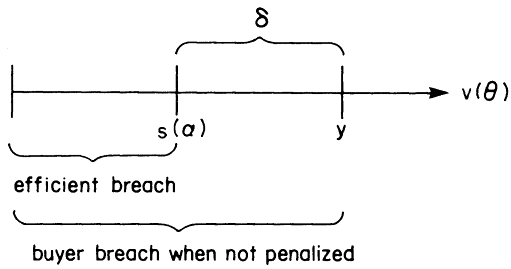

FIGURE 1

courts, and rejection of deliveries becomes an option that may be unilaterally invoked by the purchaser.

Since the optimal penalty for breach declines as a well is depleted, gas contracts usually express the penalty for refusing delivery as a fraction of reserves or deliverable capacity. In that way, the penalty obtaining in each successive period covered by the contract adjusts automatically to the declining level of remaining reserves. Written as a percentage, γ, of the contractually specified payment, the penalty described above becomes

$$\gamma = 1 - s(\alpha)/y. \tag{1}$$

Since y must be at least as great as $s(\alpha)$ to cover the fixed costs of production and induce the producer to enter the contract with the pipeline, the optimal take percentage will be nonnegative. As a rule, $s(\alpha)$ will equal y only when the producer can sell his output to another pipeline that comparably values the gas, which is unlikely unless the producer is already connected to several pipelines. At the other extreme where gas has no alternative value to the producer, the optimal take percentage is 100 percent, which would be the case, for example, were all of the gas drained away by nearby wells if not extracted by the producer himself.

C. *The Effects of Regulation*

In general, contract terms perform two functions. First, they permit parties to establish a division of the gains from trade that allows both to cover fixed costs; and second,

the buyer may gradually decrease the quantity of gas taken from the producer yields the same qualitative results.

[13] By no net return, we mean zero revenues. Note that a pipeline's willingness to fulfill the terms of a contract may also depend on the opportunity to purchase alternative low-cost gas supplies. In that case, his return in the event of breach would be $\max\{0, \bar{v}\}$ where $\bar{v}$ is his net revenue from the alternative purchases. This possibility does not affect the optimal breach penalty discussed below.

[14] The efficiency of the expectation damage has been demonstrated elsewhere; see, in particular, J. H. Barton (1972), and Steven Shavell (1980). Richard Pierce (1983) has noted that under the Uniform Commercial Code, a pipeline would be liable to a producer for "the difference between the market price and the contract price of the gas available but not taken" (p. 79), precisely the penalty described above. Note that take provisions only address the problem of buyer breach, and as such are only adopted where the principal source of uncertainty is on the demand side of the transaction, a condition true of both coal and gas production. In practice, parties must base their choice of δ on the conditional expectation of $s(\alpha)$ in the event of breach.

they determine the performance incentives in force during execution of the agreement. When contract terms are freely set, transfers between the parties prevent distributional considerations from interfering with the choice of incentive structures.

Thus far we have seen that take obligations serve the second of these functions, and that buyers and sellers may have an incentive to specify such terms even in the absence of regulation and risk aversion. The presence of price controls, however, may distort those incentives. In the case of natural gas, wellhead price restrictions prohibit certain divisions of gains and create an excess demand for gas production capacity. As a result, producers may engage in nonprice competition for capacity through the choice of contract terms. In that regard, raising take obligations will, *ceteris paribus*, increase the amount the seller receives when the buyer rejects delivery, thereby raising the expected value of the contract to the seller.[15] By setting a take percentage greater than the optimal level, the parties in effect sacrifice some efficiency in performance incentives in order to achieve a higher level of investment. The take percentage that would be chosen in a regulated transaction becomes

$$\gamma = 1 - s(\alpha)/y + D, \tag{2}$$

where $D > 0$ reflects the excess demand induced by the presence of binding price constraints.[16]

[15] Because an increase in γ both raises the amount paid in the event of breach and reduces the number of states in which breach occurs, it is possible that beyond some point an increase in γ could, depending on the distribution of θ, reduce the expected value of the contract to the seller. In equilibrium, however, more restrictive price ceilings lead unequivocally to higher take percentages on the margin (see our 1984 working paper).

[16] The additive form of equation (2) follows directly from the model in our earlier paper where we characterize efficient contracts between a producer and a pipeline. The choice of γ in an efficient contract is shown to be a second-best response to the existence of a regulatory price ceiling.

II. Empirical Results

Here we employ data on natural gas producer-pipeline contracts and associated well attributes to test the relationship characterized by equation (2), which we rewrite for estimation purposes as

$$\gamma_i = 1 - s(\alpha_i)/y_i + \xi D_i, \tag{3}$$

where ξ is a coefficient measuring the effects of excess demand, D_i, on take percentages. Prior to estimating this relationship, we describe the data used in the estimation and construct a proxy for D_i.

A. *Gas Contracts and Well Characteristics*

The data used for this study were obtained from several sources. Information regarding price and take obligations was obtained from a survey (EIA-758) conducted by the Energy Information Administration (EIA) in 1982. Through this survey, the EIA obtained detailed data on 659 contracts governing the interstate sale of natural gas from 615 wells located in the lower 48 states. The contracts included in the survey were randomly selected from post-1978 wells which qualified for incentive pricing under Sections 102, 103, 107, and 108 of the Natural Gas Policy Act (NGPA, 1978).[17] Since the data were obtained in disaggregated form, we were able to examine the relationship between take obligations and well characteristics on a well-by-well basis.

Information on the characteristics of the wells governed by these contracts was obtained independently from records at the EIA. Data availability reduced the sample to approximately 300 contracts governing onshore gas priced under NGPA sections 102 ("new" natural gas), 103 ("new" onshore production wells), and 107 ("high cost" gas from deep wells, tight sands, Devonian shales or geopressurized brine).

[17] For a more complete explanation of the survey methodology, see EIA, "Natural Gas Producer/Purchaser Contracts..." (1982).

The variables employed in the estimations are:

γ_i = the contractually specified take percentage for a contract covering gas produced from well i;

$\bar{p}_i$ = the applicable price ceiling (if any) for this gas in October 1981;

p_i^0 = the actual contract price for the gas in October 1981;

D_i = a measure of excess demand for gas from well i;

$DEPTH_i$ = the depth in feet of well i;

$BUYERS_i$ = the number of independent pipelines serving the gas field tapped by well i;

$SELLERS_i$ = the number of independent producers operating in the corresponding field;

$HERF_i$ = the Herfindahl numbers equivalent for the concentration of pipelines in the FERC gas region corresponding to well i,

$$=[\Sigma_t(R_{it}/T_i)^2]^{-1};$$

where R_{it} is the dedicated reserves of interstate pipeline t in FERC gas area i, T_i is the total amount of reserves dedicated to interstate pipelines in the gas area, and the summation is taken over all of the interstate pipelines with reserves in the gas area.[18]

B. *Excess Demand*

As a proxy for the effect of a price ceiling on the demand for gas, let

$$\begin{aligned} D_i &= p_i^* - \bar{p}_i \quad \text{if} \quad p_i^0 = \bar{p}_i; \\ &= 0 \qquad\qquad \text{if} \quad p_i^0 < \bar{p}_i \end{aligned}$$

where p_i^* is the price that would have obtained for well i in the absence of price constraints, and $\bar{p}_i$ is the applicable price ceiling. Thus, if the constraint on price is not binding, $D_i = 0$, and γ is affected only by $s(\alpha)$. If the ceiling is binding, however, D measures the difference between the unconstrained and ceiling prices.

Since p_i^* cannot be observed for $p_i^* \geq \bar{p}_i$, we employ maximum likelihood techniques to construct an estimate for this variable. Where the observations of the dependent variable are truncated, as is the case here, Tobit is an appropriate estimation procedure.[19] In particular, suppose that $p_i^* = aW_i + e_i$, where W_i is a vector of well characteristics affecting p_i^*, and e_i is normally distributed with zero mean and variance σ^2. Then the observed price in a contract covering well i would be

$$\begin{aligned} p_i^0 &= p_i^*, \quad \text{if} \quad p_i^* < \bar{p}_i, \\ &= \bar{p}_i, \quad \text{if} \quad p_i^* \geq \bar{p}_i. \end{aligned}$$

The likelihood function of the ith observation is

$$\begin{aligned} L_i &= f(aW_i) \qquad \text{if} \quad p_i^0 < \bar{p}_i, \\ &= 1 - F(aW_i) \quad \text{if} \quad p_i^0 = \bar{p}_i. \end{aligned}$$

Estimates for p_i^* are derived by maximizing the likelihood function,

$$\Lambda_i = \prod_1^N L_i,$$

with respect to a and σ^2.

Results of the estimation of p_i^* are reported in Table 1. The price at which gas is exchanged in an unregulated transaction depends upon the costs of drilling and connecting the well to a pipeline, as well as on the relative bargaining positions of the transactors. In general, one would expect drilling costs, and hence price, to be positively related to the depth of the well. Also, a large

[18]In order to construct a pipeline, the Natural Gas Act (1938) requires that the transmission company obtain a certificate of public convenience and necessity from FERC. One requirement is that the transmission company demonstrate "adequacy of reserves"; i.e., a sufficient supply of gas to keep the pipeline in operation. As a result, gas reserves are often contractually "dedicated" to individual pipelines. Thus one indicator of the proximity and capacity of pipelines in a geographical region is the number of pipelines that have dedicated reserves in the area and the relative size of those reserves. The information used to compute this measure was obtained from EIA, "Gas Supplies of Interstate Natural Gas Pipeline Companies–1980," (1980).

[19]See, for example, G.S. Maddala (1983).

TABLE 1—ESTIMATION OF p^*

Variable	Coefficient	T-Ratio	Mean
CONSTANT	1.0623	10.890	1.000
DEPTH	$.27465\times10^{-3}$	4.4689[a]	10368.
HERF	.35661	2.7472[a]	4.8687
BUYERS	.34237	2.6665[a]	4.5709
SELLERS	−.06202	−2.4156[b]	9.3041
Chi-square: 403.333 with 4 degrees of freedom[c]			
Number of observations: 296			
Proportion of observations for which $p^0 < \bar{p}$: .1757			

[a]Indicates significance beyond the .01 level.
[b]Indicates significance beyond the .05 level.
[c]Indicates significance beyond the .001 level.

number of buyers and sellers in a particular gas field would tend to undermine the respective group's bargaining position, with corresponding effects on price. In addition, to the extent that connection costs are reduced by the proximity of transmission lines, increases in the concentration of pipelines serving an area should also raise the value of the transaction. The availability of alternative pipelines depends both on their number and transmission capabilities. The Herfindahl measure defined above provides a proxy for the proximity of pipeline capacity to a particular well.

As can be seen from Table 1, the coefficient on each of the variables has the expected sign and is significant beyond the .05 level.

C. *Take-or-Pay Percentages*

We may now turn to estimating the effects of alternative values and excess demand on take percentages. To derive an estimate of $s(\alpha)$, the alternative value of a well, recall that this value will be the maximum of two alternatives: the resource value, which is the discounted value of the gas if left in the ground to be sold at a later date less losses due to drainage by other wells; and the sale value, which is the net value of the gas from sale to another pipeline.

Letting X_i be a vector of attributes affecting the resource value and Z_i a vector affecting the sale value, the expected value of the gas in an alternative use may be represented as

$$s(\alpha_i) = (\beta_1 X_i + \beta_2 Z_i) q_i,$$

where q_i is the capacity of well i, and β_1 and β_2 are coefficient vectors.[20]

Substituting into equation (3) and adding an error term, ε_i, yields

$$(3') \quad \gamma_i = 1 - \beta_1 \frac{X_i}{p_i^0} - \beta_2 \frac{Z_i}{p_i^0} + \xi D_i + \varepsilon_i.$$

The theory of the preceding section predicts that well characteristics, X and Z, which raise (lower) the alternative value of developed capacity should lead to a decrease (increase) in the size of take obligations, and thus implies negative (positive) values of the corresponding coefficients in β_1 and β_2. Meanwhile, we would expect that the more constraining the price ceiling, that is, the greater $p_i^* - \bar{p}_i$, the larger should be γ_i, implying $\xi > 0$.

In determining the resource value of the gas, the larger the number of sellers in a field, the greater the drainage that would occur if a producer were forced to "shut in" his supplies, and hence, the lower this alternative value. The alternative sale value in turn would be expected to increase with the availability of alternative purchasers as measured by the number of buyers in the field and the number of pipelines in the region. Hence, *BUYERS* and *HERF* should both raise the expected alternative value of a well, implying a lower take percentage, and *SELLERS* should reduce $s(\alpha)$ and raise γ.

The ordinary least square (*OLS*) estimates of (3′) are presented in Table 2. (The prefix *S* on a variable indicates that it has been divided by price, see equation (3′). Also note that γ is expressed in percentage terms rather than as a fraction.) Each of the coefficients in this regression has the predicted sign and is

[20]It would be possible to estimate $s(\alpha)$ as the maximum of its resource and sale values using switching regression techniques (see Maddala). We have chosen instead to let well characteristics affect the *expected* value of $s(\alpha)$ additively for its relative computational ease.

TABLE 2—ESTIMATION OF TAKE OBLIGATIONS

Variable	Coefficient	T-Ratio	Mean
CONSTANT	82.0822	43.6650	1.000
SSELLERS	.4833	2.0927[a]	3.9819
SBUYERS	−1.3136	−1.7589[b]	2.1080
SHERF	−.8646	−1.7929[b]	2.3270
REGCONST (D)	1.85132	3.9956[c]	2.8897

F: 13.24079 with 4 and 294 degrees of freedom[c]
Number of observations: 299
$R^2 = .1526$

[a] Indicates significance beyond the .05 level.
[b] Indicates significance beyond the .1 level.
[c] Indicates significance beyond the .001 level.

statistically significant beyond the 10 percent level. The evidence is thus consistent with the hypothesis that take percentages are designed to influence adaptation in long-term contracts and, in particular, are negatively related to the alternative value of gas reserves. Moreover, price ceilings seem to have the predicted effect on take provisions, raising the percentage paid for nondelivery. The findings indicate that, at the mean, a 1 percent decrease in the price ceiling will lead to a 6 percent increase in the take obligation. For the mean values of the independent variables, the regulatory price ceiling increases the predicted take obligations from 79 to 85 percent.

III. Conclusions

The results of this paper suggest that the incentive to provide flexibility in long-term contracts is an important consideration in the design of contract terms, and that the nature of those terms can be predicted on the basis of characteristics of the transaction. In particular, we have identified an efficiency motivation for the inclusion of take-or-pay provisions in long-term agreements: take obligations induce purchasers to release output to alternative uses only when it is efficient to do so. These incentives may be distorted, however, by the existence of regulated price ceilings. In the case of natural gas, government regulation of wellhead prices appears to have caused nonprice competition in take obligations leading to higher percentages than would prevail in the absence of such regulation.

Empirical tests presented in the paper support the hypotheses of the model. Take percentages are significantly lower for wells associated with small numbers of sellers and large numbers of buyers, each of which raise the alternative value of the gas, a result which seems to apply more generally: E. M. Carney, for example, has noted that, in coal contracts, "If... the coal mine has no access to other markets, the seller obviously has more need for a take or pay clause than he would otherwise"; while, on the other hand, "If the seller can get his product to other markets, the take or pay provision is often tempered to reflect that fact" (p. 226).

The evidence presented here refutes the common perception that take-or-pay provisions are soley an artifact of wellhead price regulation and hence serve no useful purpose in the absence of regulation. Providing that externalities do not result in a divergence of private and social valuations,[21] take obligations contained in contracts written in unregulated environments provide for efficient adaptation to changing circumstances in long-term contractual relationships. Whether a policy to reduce excessive take provisions to *ex post* optimal levels should be advocated on the basis of regulatory interference depends upon both the current regulatory status of the gas covered by the contract and the regulatory environment expected to govern the sale of gas discovered in the future. For example, if the gas under consideration has

[21] Where a field is exploited by a single producer, the gas production process involves no obvious externalities. With more than one operator, however, gas not sold by one producer may be captured and profitably marketed by other producers in the same field. In that event, the social value of "shut in" gas is apt to exceed the value of that gas to the original producer, leading to the adoption of take provisions in excess of socially optimal levels. To the extent that the drainage problem is exacerbated by the number of sellers in the field, the results in Table 2 suggest that take percentages are raised by less than one-half of 1 percent above the socially optimal level for each additional producer in a given field. This implies that, on average, take percentages exceed their socially optimal levels by less than two percentage points due to the externalities associated with competitive extraction from a common pool.

been deregulated and deregulation is expected to continue in the future, the possibility of private bilateral renegotiation obviates the need for intervention. With the removal of the price ceiling, the efficiency gains arising from the reduction of take obligations can be distributed between the buyer and seller through price adjustments, effecting a true Pareto improvement.[22]

Contract terms should also be upheld for categories of gas that currently remain regulated if price regulation is expected to be extended into the future: the precedent established by a reduction of take percentages from the second-best levels stipulated in the contracts could seriously distort capacity investment decisions for future wells. On the other hand, if future discoveries are expected to be sold in an unregulated environment, the efficiency gain from a one-time reduction in take obligations is not offset by adverse precedential effects on future investment. In this event, a prima facie case can be made for intervention to reduce take obligations to levels consistent with efficiency absent regulation. However, these potential benefits must be weighed against the ability of the government to intervene advantageously. Inasmuch as optimal take percentages depend upon characteristics of individual wells, effective intervention would require well by well adjustments. Given the government's previous record on well-specific regulation (see fn. 1), the practicality of this solution is in doubt.

[22] While such renegotiation is certainly not costless, it is likely to be less expensive and more precise than either judicial or legislative intervention.

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