

Gas Contracting: The Lessons of the Seventies

John S. Lowe

With the penetrating vision of hindsight, it is apparent that both buyers and sellers of natural gas made fundamental mistakes in negotiating gas contracts during the 1970s. Producers and pipelines overestimated future demand, with the result that they entered into long-term contracts at unrealistically high prices and with huge take-or-pay obligations. The result of these errors has been that thousands of producers have not received payments that they counted on to continue their businesses, and the financial well-being of several large pipelines has been thrown into jeopardy.

Bitter experience with gas contracts of the 1970s has taught those associated with the natural gas industry lessons that are reflected in a new breed of contract. Sensitivity to market conditions is the watchword for the hard times of the 1980s.

Both buyers and sellers grossly misjudged what the demand for natural gas would be in the 1980s as they negotiated in the 1970s. While supply remained relatively stable, the demand for natural gas shrunk approximately 21 percent between 1979 and 1986, from 20.2 trillion cubic feet to 16.0 trillion cubic feet. The following statistics, from the 1987-88 edition of *Natural Gas Trends*, published by Arthur Anderson & Co. and Cambridge Energy Research Associates, summarize the decline:

**Natural Gas Consumption in
Trillions of Cubic Feet**

Year	Residential	Commercial	Industrial	Electric Utilities	Other
1979	5.0	2.8	6.8	3.2	2.2
1986	4.4	2.3	5.2	2.6	1.6

Current estimates of the surplus of natural gas range between two and four trillion cubic feet.

What happened? How did the United States move so quickly from an economy that seemed unable to get enough natural gas to one with such a large surplus? The answer appears to lie in a combination of economic and regulatory effects that have interacted somewhat differently upon different segments of the economy.

Conservation was an important factor. Natural gas demand for residential and commercial purposes declined 12 percent and 18 percent, respectively, from 1979 to 1986 as a result of lower thermostat settings and increased efficiency of furnaces, air conditioners, and appliances. Millions of home owners and business people insulated their attics, installed storm windows, caulked the seams of their buildings, and replaced energy inefficient appliances with equipment that worked better on less natural gas or electricity.

Structural change and fuel switching were also important in the decline of demand for natural gas, particularly in the industrial and electrical utility sectors. The use of natural gas in industry and for the generation of electricity, which together still account for nearly half of the total demand, dropped approximately 19 percent from 1979 to 1986. Increased efficiency of equipment played a role in the decline, but more important was the profound structural change in U.S. industry away from energy intensive uses of natural gas during the period. For example, U.S. steel production declined 40 percent during the years in question. To some degree, high-tech industries replaced steel in our economy, and making computer chips consumes much less natural gas than making steel girders.

Fuel switching, from gas to oil and coal, was a second factor causing a decline in industrial and electric generating demand for natural gas. The gas shortage of the 1970s led businesses constructing new industrial plants and utility generating plants to install fuel switching capacity so that they could keep their doors open even if they could not get natural gas. When the prices of oil and coal began to slide, fuel switching capacity was used to lower operating costs. The decline in the use of gas was accelerated by the Power Plant and Industrial Fuel Use Act of 1978, which prohibited the construction of new electrical generating plants that burned natural gas. Though we now have a gas surplus and the Fuel Use Act was repealed in 1987, we have a whole generation of electric facilities that cannot burn gas, and twenty years of industrial plants that can rapidly switch from

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gas to coal to oil and back again, some literally on a daily basis. *Natural Gas Trends* estimates that nearly 40 percent of end-use consumption presently occurs in facilities with some alternative fuel capacity and that at least a third of the combined industrial and electrical generation markets can switch at virtually no cost within a few days.

The interaction of conservation, structural change, and fuel switching was exacerbated by rising prices to natural gas consumers. While oil prices peaked in 1981, natural gas prices at the burner tip continued to increase until 1984, rising 28 percent in the three-year period before turning modestly downward for residential users and sharply downward for industrial and electrical users. As will be discussed below, gas contract provisions were partly responsible for the rise of prices in the face of a decline in demand. So too was the Natural Gas Policy Act of 1978 (NGPA), which provided for incentive pricing.

In the early 1970s, policy makers were convinced that this country would never again have enough natural gas. A variety of policies to encourage conservation and promote new production were implemented, chief of which was the NGPA. The NGPA was based upon the premise that natural gas prices should be deregulated, but it sought to protect the U.S. economy against "price shock" by postponing deregulation until 1985 and extending federal regulation to the intrastate market. The scheme of the NGPA was to regulate prices at ever higher levels until the gap between the regulated price and the free market price was small, at which time deregulation would begin. NGPA worked—it stabilized supply and provided a structured escalation of regulated prices—but it actually accelerated the decline in natural gas demand. Many of NGPA's "maximum lawful prices," which were translated into actual prices paid by the gas contracts of the 1970s, exceeded the free market price well before 1985.

When oil prices plunged in early 1986, however, the NGPA deregulation process had already begun, and prices on the growing spot market dropped like a rock. According to *Natural Gas Trends*, the spot price for gas delivered to major pipelines from the Texas offshore producing area fell from \$2.18 per mcf in January 1986 to \$1.41 per mcf in November 1986. Prices have recovered somewhat since then, but they remain sensitive to the prices of competing fuels.

In the late 1980s, natural gas has become just another fuel which must compete with coal and oil—and perhaps garbage and surplus

corn—for market share. Natural gas must now compete in a free market.

Contracts of the Seventies

As many producers and pipelines negotiated gas contracts in the 1970s, they did not anticipate the decline in natural gas demand of the 1980s. In fact, their contracts exacerbated the decline in demand. Three contract provisions lay at the heart of the problem—the term, quantity, and price escalator clauses. These provisions contributed to the inflexibility of the market for natural gas, which in turn accelerated the decline in demand.

Gas contracts of the 1970s were for long terms. Twenty-five-year or "life-of-the-well" agreements were common, as they had been since the interstate pipelines were built. In part, long terms reflected regulatory requirements. The Natural Gas Act of 1938 required that gas dedicated to interstate commerce be subject to a minimum fifteen-year contract. Economic considerations also demanded long terms. Long-term commitments were a condition of the complex financing arrangements entered into for the construction of many of the interstate pipelines. Even after the construction loans were paid, the maintenance and operation of pipelines generated high fixed costs, so that pipeline gas buyers placed long contract terms as a high priority in negotiations.

When the demand for natural gas declined sharply in the 1980s, long contract terms exacerbated the disputes between producers and pipelines. However bad a deal may be, it is easier to tolerate it for a short term than for many years.

How much of a commodity will be taken at a given price is as important as the price itself in determining profitability. Gas wells will not always deliver when gas is desired, however, and purchasers' needs vary with the season and the state of the economy. Therefore, gas contracts of the 1970s typically contained lengthy and complicated provisions addressing the quantity of gas that the seller was obligated to provide and the amounts that the buyer had to take.

The most important of the quantity provisions usually seen in 1970s gas contracts was the take-or-pay clause. A take-or-pay clause obligates a purchaser to pay for a percentage of the gas which the producer can produce, whether or not the purchaser actually takes it. Take-or-pay clauses usually permit the purchaser to make up gas paid for but not taken. The clause provides the producer with a guar-

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anteed minimum cash flow in return for dedicating the gas supply to the purchaser.

In the 1970s, pipelines often used favorable take-or-pay terms as an incentive to induce producers to sell to them. Price regulation under the Natural Gas Act and the NGPA effectively barred price competition by purchasers, so pipelines competed by offering attractive nonprice terms. Producers saw the clauses as risk-shifting devices that would protect them against demand fluctuations. Take-or-pay percentages increased from as low as 35 percent in the early 1970s to 90 percent at the height of the boom.

When gas demand declined sharply, many pipelines found themselves confronted with huge liabilities. Estimates vary widely, but total potential liability of U.S. pipelines was probably in the range of \$15–30 billion over the life of their contracts. Several major pipelines confronted contingent liabilities several times the value of their assets.

Producers faced serious difficulties also, for they had never dreamed that pipelines would neither take nor pay. However, that is exactly what happened. The Natural Gas Supply Association estimated in 1987 that only 2.6 percent of the outstanding take-or-pay obligations for 1984–85 had been paid.

In the mid-1980s, the take-or-pay problem was exacerbated in the short run by the efforts of the Federal Energy Regulatory Commission (FERC) to deregulate the natural gas industry. In 1984, FERC Order 380 permitted the customers of interstate pipelines to escape the burdens of variable-cost minimum bill provisions. Minimum bill provisions were similar to take-or-pay clauses in that customers were required to pay for minimum quantities of gas whether or not they actually took the gas. In 1985, FERC Order 436 provided a combination of carrots and sticks to encourage pipelines to elect to become open access transporters of natural gas. One result of FERC's efforts was the creation of a burgeoning spot market for natural gas in which pipelines function as transporters rather than as merchants. According to *Natural Gas Trends*, major pipeline companies sold only 7 tcf of the 16.2 tcf of natural gas used in 1986. Another result was that take-or-pay liabilities of pipelines soared as consumers turned to the spot market for cheaper gas.

Litigation over take-or-pay clauses boomed in the mid-1980s. Producers brought billions of dollars of claims for take-or-pay payments against their pipeline purchasers. Facing financial ruin, the pipelines resisted fiercely, raising a variety of affirmative defenses.

Force majeure and commercial impracticability are the most important defenses against take-or-pay claims, but they have been effective only infrequently. The *force majeure* defense is based upon contractual provisions that define when the parties are to be relieved of their obligations. It has rarely succeeded because the language of the *force majeure* clause in gas contracts does not ordinarily define market failure as a *force majeure* event. Moreover, the courts have been reticent to find that a few words in a "boilerplate" clause are intended to override the lengthy and detailed take-or-pay provisions. The commercial impracticability defense has its roots in the common law and the Uniform Commercial Code. Performance is excused if made impracticable by the occurrence of a contingency that the parties had assumed would not occur. Thus far, the courts have generally rejected the notion that failure of the gas market is a basis for commercial impracticability; there have been market disruptions for as long as there has been a gas industry. A better argument for the pipelines, which has not yet been fully tested, is that FERC's restructuring of the gas industry by Order 380 and Order 436 is a basis for a defense of commercial impracticability. The strength of this argument, however, turns on when the contract was executed; it should have been apparent well before Order 380 was proposed that the market was not functioning.

Pipelines and producers have settled many take-or-pay claims and, after prodding from the courts, FERC has tried to ease the pipelines' predicament with Order 500, requiring producers who wish to transport gas to offer the transporting pipelines volume-for-volume credits against take-or-pay liabilities. Still, billions of dollars of claims are before the courts, and many producers (or their bankruptcy trustees) may decide that continuing litigation over long-term, high-priced, high-percentage take-or-pay contracts is more profitable than producing and selling gas. The legacy of the contracts of the 1970s continues to trouble the natural gas industry.

In addition to long terms and minimum take requirements, 1970's contracts included price adjustment terms which exacerbated the purchasers' burdens. The long-term contracts of the 1970s contained price adjustment provisions because the parties could foresee that the initial price agreed upon when the contract was formed would not be likely to be fair over the long run. Price adjustment provisions in gas contracts of the 1970s usually reflected the premise that

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what went up would never come down and that a fair price for natural gas would always be higher in the future than in the past. A variety of escalator clauses were included, often with the proviso that the clause that yielded the highest legal price would apply. As a result, contract prices climbed steadily higher, increasing the burden of take-or-pay obligations.

Gas contracts of the 1970s often included definite price adjustment clauses, provisions that called for periodic fixed or percentage price escalations. Definite price adjustment provisions invariably ratcheted the contract price higher. I have never seen a definite price adjustment clause that provided for a downward adjustment.

Contracts of the 1970s also usually contained a variety of indefinite price escalator clauses, by which the price was redetermined by reference to factors outside the contract itself. Two such clauses, the "area rate" clause and "the most favored nations" clause were particularly troublesome, for they worked together to push contract prices upward in a stair step fashion, while demand slid down the bannister.

Area rate clauses were common to contracts covering gas that was subject to federal price regulation at the time the contract was executed. An area rate clause provides for periodic price increases to the highest price permitted by the appropriate regulatory body for gas being sold in the area. After passage of the NGPA, FERC held that area rate clauses might be triggered by maximum lawful prices established under the NGPA. As a result, the price of large quantities of "old" gas escalated sharply and then adjusted upward each month.

The favored nations clause tied the contract price to prices being paid in the area for gas of comparable quantity and quality at the time of sale. Once the incentive prices approved by the NGPA began to be paid, however, area rate clauses operated to increase the price for "old" categories of natural gas to the maximum prices permitted by NGPA. The favored nations clause in one contract was often triggered by the area rate clause in another. Thus, each monthly increase in the maximum lawful price permitted by the NGPA set off a new round of contract price increases.

Other indefinite price adjustment provisions in gas contracts of the 1970s that might have made contract prices responsive to demand were drafted so that they did not apply. Parties to 1970s-era gas contracts who anticipated that the federal government would eventually cease regulating gas prices at the wellhead often included a "price renegotiation" clause

to set out the procedures for negotiation in a free market. Most 1970s renegotiation provisions worked only one way, however, permitting renegotiation only at the demand of the producer. Furthermore, they applied only after price deregulation. The decline in demand predated official price deregulation in 1985, and the pipelines wanted to renegotiate, not the producers. Thus, price renegotiation clauses were ineffective in counteracting price increases mandated by area rate and favored nations clauses.

The "price index" clause was a second type of indefinite price escalator provision often seen in 1970s gas contracts that might have made contract prices responsive to market demand, but did not. A price index clause sets price by reference to changes in the indices of prices for other fuels, particularly those that compete with natural gas. Price index clauses in gas contracts of the 1970s included oil reference clauses (which keyed prices to the price of fuel oil in the primary market area of the purchaser), imported gas reference clauses (which adjusted the price by reference to changes in the price of gas imported from Canada or Mexico), and electric reference clauses (which provided for changes in natural gas prices by reference to changes in the price of electricity). In most 1970s contracts, however, price index clauses, like renegotiation clauses, were triggered only at the option of the seller, and the seller was entitled to the highest price determined by any variation of the clause or by any other price escalator clause. Thus, price index clauses had little effect upon the inexorable increases of gas prices.

The combination of high take-or-pay percentages, escalating prices, and collapsing market demand for natural gas would have been even more devastating for the industry had it not been for the "market-out" clause. A market-out clause, or an economic-out clause, as it is frequently termed, permits a natural gas purchaser to demand lower prices or to cancel the contract when the price set by the price escalation provisions is too high. Market-out clauses appeared frequently in contracts by 1980. They reflected the concern of some purchasers that the price surge that began in the mid-1970s would ultimately make natural gas uncompetitive with other fuels.

A market-out clause generally permits the gas purchaser to lower the price at the wellhead when gas purchased at that price cannot be sold profitably in the purchaser's primary market. Early versions of the market-out clause were ob-

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The "area rate" clause and the "most favored nation" clause were particularly troublesome, for they worked together to push contract prices upward in a stair step fashion, while demand slid down the bannister.

tion of the Interior Board of Land Appeals (IBLA) affect public participation in management of federal public lands. She argues public intervention rights should be granted broadly at the initial stages of administrative BLM proceedings, but that public intervention in or right of appeal to the IBLA should be restricted based on the person's ability to enhance the decision-making process. This interest representation model would closely reflect the broad jurisdiction and mandate of the BLM.

Solid and Hazardous Waste

Abraham, "Environmental Liability and the Limits of Insurance," 88 *Columbia Law Review* 942 (1988). The author reviews the impact of environmental liability on the liability insurance market. The causes of the liability insurance crisis of the mid-1980s are examined. The author posits that, whereas in most fields of tort law liability insurance has followed developing law, the environmental law area has not evidenced the same willingness of insurance providers to cover the risk. This may be due to special considerations present in the environmental liability field, which the author contends courts and legislators should take into account.

Glass, "Superfund and SARA: Are There Any Defenses Left?" 12 *Harvard Environmental Law Review* 385 (1988). The author reviews the liability imposed on private parties by the Superfund law. She contends that the Environmental Protection Agency (EPA) has zealously and systematically sought expansion of Superfund liability on all fronts, which the courts have granted almost completely. She argues that EPA's motivation has been to establish a "deep pocket" assessment of liability, and she attempts to demonstrate this through a detailed, up-to-date discussion of virtually every defense that has ever been raised to Superfund liability. She concludes that recent developments, such as the 1986 amendments to the Act, may indicate an era of fault-related imposition of liability.

James, "Financial Institutions and Hazardous Waste Litigation: Limiting the Exposure to Superfund Liability," 28 *Natural Resources Journal* 329 (1988). The author focuses his discussion on the Superfund liability that falls upon financial institutions which foreclose upon security interests in active disposal facilities or become the innocent subsequent owners of abandoned hazardous waste sites. He recommends a course of action for financial institutions to take to minimize the risk of unintentionally assuming such liabilities, including indemnifications, environmental risk assessments, and environmental audits. 

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jective, providing for price adjustment by reference to competing fuels:

If at any time Buyer's average rolled-in gas cost at _____, including all transportation and allocable costs, exceeds the BTU equivalent cost of the lowest priced #2 fuel oil, as officially posted the first business day of each month by Platts Oilgram for the _____ area, Buyer shall have the right to redetermine the price for gas purchased and sold hereunder.

Later versions of the market-out clause gave the buyer broad discretion to determine when price adjustment was necessary. For example:

Notwithstanding any other provisions in this agreement, the price to be paid for any gas delivered or for which payment is due hereunder including taxes, shall never exceed . . . a price which will prevent buyer's resale of gas from its pipeline system to its customers. Buyer, in its sole opinion, will determine whether the purchase of gas under the pricing provisions hereof will result in gas prices which buyer's customers will not be willing to pay.

Pipelines that had market-out clauses in their contracts could force contract prices downward so as to compete for market share. Without such clauses, both the decline in demand and the take-or-pay carnage among pipelines would have been worse. Of course, producers whose contracts contained these strange provisions—which were not exercised until 1982—are less sanguine about their effect.

A New Generation of Gas Contracts

The hard times of the natural gas industry in the 1980s and the changes in its structure are reflected in a new generation of gas contracts. As the industry moves into the 1990s, the watchwords of contract drafters are flexibility and market responsiveness.

One apparent difference between gas contracts of the 1970s and the new generation of

gas contracts is the identity of the purchaser. Contracts of the 1970s were almost always between producers and pipelines. Pipelines bought gas from producers and then sold it to local distribution companies, which in turn supplied end users—residences, businesses, industrial plants, and electrical generators. As a result of FERC Order 436, however, most pipelines now transport gas as well as buy it for resale. This development means that producers may sell to gatherers, to brokers, to local distribution companies, or to end users, as well as to pipelines. The diverse interests of the new players in the market mean that there is substantially more variety in 1980s contract terms than in those of the 1970s.

The new generation of gas contracts differs substantially from gas contracts of the 1970s in their provisions for term, quantity, and price. Most current gas contracts are for short terms, ranging from a few days to a year. The philosophy appears to be “let’s go along as long as we get along,” and the short terms are often coupled with “evergreen” provisions that extend the contract after its initial term until one of the parties gives notice, usually of only a few days or weeks, of termination.

Take-or-pay provisions are rarely found in contracts in mid-1988. A few pipelines still agree to take or pay for modest percentages of well delivery capacity—perhaps 15–20 percent—but even they combine the take-or-pay clause with flexible pricing terms. Short-term contracts may in fact impose no quantity obligation upon buyers. The longer term contracts are likely to replace the take-or-pay provision with a “take or release” clause, which gives the seller the right to terminate the contract if the buyer does not take minimum amounts of production.

It is the pricing provisions of the new generation contracts, however, that differ most sharply from the gas contracts of the 1970s. New contracts may contain a variety of provisions, including some modeled upon price escalator clauses of the 1970s, but new price adjustment provisions are much more flexible and responsive to market demand than their predecessors of the 1970s.

Perhaps the favorite clause of those purchasing gas for resale—pipelines or gas brokers—is the “net-back” clause. A net-back clause sets the price to be paid to the producer by “netting back” the price received from the ultimate sale, less transportation charges and costs incurred. The purpose of the net-back clause is to permit natural gas to compete aggressively with alternative fuels in the pur-

chaser’s market area. Under this clause, gas is sold for whatever the market will bear, and the producer’s price is calculated back. An example of a net-back clause follows:

Buyer shall pay seller . . . a price per MMBTU, inclusive of all taxes and other additives, equal to the weighted average sales price for that month multiplied by seller’s contract percentage, less the sum of (1) all fees and charges incurred by buyer or its agent to have the gas purchased hereunder transported . . . and (2) all fees and charges, if any, that buyer charges seller to dehydrate, compress, treat, meter, condition, or gather the gas. . . .

Net-back clauses have caused producers to become more involved in regulatory rate-making proceedings because what the producer gets is affected directly by the rates of the transporters. As the cost of transportation increases, the amount received by the producer declines. In addition, they raise difficult interpretative problems that are yet to be litigated, e.g., what “fees and charges” are “incurred” in transportation.

Another price adjustment clause that permits strong competition between natural gas and competing fuels is the “meet or release” clause. A meet or release clause gives the buyer some assurance that the gas it purchases will be competitive by letting the buyer either force down the price it pays to the seller or buy from a new source. Often, meet or release clauses are modeled on market-out clauses:

If . . . the price payable hereunder becomes uneconomical for Buyer, or the transportation fees for gas purchased hereunder are increased or become uneconomical for Buyer, or the price of any equivalent fuel becomes competitive with the price of gas hereunder, Buyer will have the right to nominate . . . a new price. . . . Seller will have the option to sell Buyer gas at the new price. . . . In the event that Seller does not accept such lower price within _____ days after receipt of Buyer’s new price nomination, then Buyer, upon _____ days written notice to Seller, may terminate this contract.


In other words, the producer must either meet the competition or release the buyer from the contract. Meet or release clauses may be drafted to give the producer the right to demand a higher price, too. Unless they work both ways—for the producer as well as the buyer—meet or release clauses are not likely to be a satisfactory pricing device in the long run.

Other price adjustment provisions frequently seen in the mid-1980s are variations of the price escalator clauses found in gas contracts of the 1970s. Renegotiation clauses are frequently used in contracts for both resale and

for sales to end users. In contrast with their predecessors, however, new generation renegotiation clauses permit either the buyer or the seller to demand price renegotiation at frequent intervals—monthly or quarterly. Price index clauses are also used, primarily to keep gas competitive with residual fuel oils. Some look very much like the objective market-out provision quoted above and require comparison of gas and fuel oil prices in the burner-tip market. Others key the contract price of gas to a percentage—e.g., 60 percent of the no. 2 fuel oil price—in the producing area.

As the title of this article indicates, business people in the natural gas industry and the attorneys who represent them have learned from the mistakes they made in gas contracts negotiated and drafted in the 1970s. The new generation of gas contracts is much more market

sensitive than the old. In my opinion, however, new generation contracts are no more litigation proof than contracts of the 1970s.

Natural gas is a commodity, and the stakes are always high in the commodities markets. Inevitably, there will be winners and losers. The stakes of the game are lowered by short-term contracts and by contracts that can be quickly renegotiated. When large quantities are involved, however—and spot market gas sales often involve huge quantities in a single transaction—the stakes are greatly increased. In addition, many economists are predicting that industrial and electric generating customers are likely to move back to longer term contracts as the gas surplus dissipates. Under either scenario, the game of gas contract negotiating, drafting, and litigation is likely to continue at a brisk pace. 

The Pipeline Perspective

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Resolving take-or-pay liability is a high priority during settlement negotiations. Take-or-pay must be addressed in two respects: accrued liability must be resolved and the prospective obligation reduced. The preceding paragraphs have covered several means of avoiding take-or-pay obligations prospectively, primarily by reducing the purchase obligation and bringing it in line with market demand.

Take-or-pay liability is more important than ever before, since FERC Order 380 has stripped away some of the protection pipelines had against take-or-pay provisions. Historically, minimum bills served as a strong disincentive for pipeline customers to buy from other sources; if a customer failed to purchase its contractual minimum amount, it had to pay for it anyway. The customer's failure to purchase may have caused the pipeline to be unable to purchase from the producer, resulting in potential take-or-pay liability. However, once the customer had made its minimum bill payment, the pipeline had a pool of funds from which to draw in making the take-or-pay payment. After Order 380, this protection is gone.

Consequently, most pipelines make waiver of accrued take-or-pay liability a condition to contract renegotiation. Waiver of take-or-pay claims may also be a condition to joining a pipeline's least-cost plan or special marketing program, although, at least in Texas, such a condition is specifically prohibited by state regulations.

FERC Order 500 has also had an impact on

take-or-pay liability. Although FERC cannot revise take-or-pay contracts, it can condition the producer's access to the pipeline. Order 500 affirms the open access provisions of Order 436 and provides a crediting mechanism for gas transported. The order provides that if the pipeline transports gas for the producer, the producer must give the pipelines a volume-for-volume credit toward take-or-pay liability accruing after January 1, 1986, on any contract between the same parties, at the pipeline's election. When the producer's alternative is to give up part of its take-or-pay claim or have no access to the market, settlement is a more attractive option.

Another facet of the take-or-pay problem is whether any outright payment to the producer for accrued take-or-pay liability must be passed through to royalty owners. The Fifth Circuit Court of Appeals in *Mesa Petroleum Company, Cities Service Oil & Gas Company and Diamond Shamrock Exploration Company v. Donald P. Hodel and United States Department of Interior*, consolidated under Nos. 87-3195, 87-4069, and 87-3207, decided in August 1988, that for Outer Continental Shelf Leasing Act (OCSLA) leases, at least, royalty need not be paid on take-or-pay payments. The producer's posture on the issue may influence his bargaining position. If he plans to keep the payment, he is less likely to exchange accrued take-or-pay liability in the bargaining process. If the payment is to be passed through, he may be willing to trade it away.

Obviously, a pipeline will want to elimi-

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