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Since 1938, when the Natural Gas Act (NGA) was enacted, the sale of natural gas in interstate commerce was predominately accomplished in a simple, straightforward manner—a producer sold its gas (directly or indirectly) to a pipeline; the pipeline then sold it to a local distribution company (LDC), which, in turn, sold it to the consumer. Thus, there were only a limited number of transactions to bring gas from the wellhead to the burnertip; those took on a relatively standard appearance.

Ultimately, virtually every step of the overall arrangement required regulatory approval, much of it at the federal level. In the last twenty years or so, the U.S. natural gas industry has weathered shortages and surpluses that have resisted cure by federal government fiat. Now, the federal government largely wants to relinquish the last vestiges of control over the production and sale of natural gas, in favor of allowing competition decide what is best for markets. Its "ticket out" is known as Order No. 636.

In what follows, we first trace the events of the last twenty years leading up to the issuance of Order No. 636. Then, we review the basic tenets of Order No. 636, previewing the general rules that will change how
gas is sold in the U.S. Finally, we discuss some more precise parameters of those changes, which are being determined as this chapter is written (in the early Summer of 1992) and will be further determined over the next twelve to eighteen months, as Order No. 636 is implemented on almost ninety interstate pipelines.

Ultimately, something similar to Order No. 636 will be implemented in state utility commission proceedings. For now, we attempt to draw on experience with other regulatory initiatives to predict what the future holds for sellers and buyers of natural gas and the legal instruments used to execute their sales and purchases.

§ 15.02 Background: Setting the Stage.

[1]--Gas shortages of the 1970's and the NGPA.

During the 1970's, the interstate natural gas market suffered periodic shortages. These shortages have generally been attributed to two related factors: (1) federal price regulation, which could not keep up with increases in market prices, and (2) efforts to avoid federal price regulation by keeping gas from moving into interstate markets. The solution to these problems was deemed to be found in integration of the markets and in federal price incentives. Integration was to be accomplished by exempting certain interstate transportation and sales activities from NGA jurisdiction. Federal price incentives were to be provided through book indexing or deregulation of gas prices. Both of these purported solutions would be instrumental catalysts for Order No. 636.

Out of the interstate natural gas supply shortages and Congress' perceived need to deregulate many heavily controlled national economic markets in order to stimulate the nation's growth grew the Natural Gas Policy Act of 1978 (NGPA).

The NGPA was "designed in principal part to encourage increased natural gas production" and to "eliminate the dual market that distinguished between interstate and intrastate sales of natural gas."

Enactment of the NGPA reflected a congressional belief that a different system of natural gas pricing was needed to balance supply and demand.

The NGPA was, therefore, Congress' attempt to dissolve the regulatory barriers between the interstate and intrastate markets. NGPA Sections 311 and 602(b)(2) were added to facilitate the development of a "national natural gas transportation network" without subjecting intrastate pipelines, already regulated by state agencies, to federal regulation.

[2]--FERC Orders Allowing Buyers and Sellers to Contract Directly.

Following enactment of the NGPA, the natural gas market experienced above-market prices and gas surpluses. These factors placed pipelines under pressure to find new ways to market their natural gas. Unfortunately, by the early 1980s, many pipelines had lost significant portions of their markets to other fuels or other sources of gas supply. Despite this declining market base, pipelines had committed to purchase large quantities of gas at above-market prices. Their average cost of gas exceeded the price that customers with access to alternative fuels or alternative gas sources were willing to pay.

Pipelines responded to this growing problem by enforcing the minimum bill provisions in their tariffs. This had the effect of limiting their customers' ability to reduce purchases or switch to alternative suppliers. Pipelines also initiated "special marketing programs" and selective transportation programs designed to
permit them to recapture customers lost to alternate fuels without experiencing any loss of revenue. This was accomplished by selling or transporting gas to customers with ready access to alternative energy supplies at prices below the pipeline's average cost, while continuing to sell gas at a higher price to captive customers.

[a]--NGPA Section 311: Order Nos. 319 and 234-B.

Not long after the enactment of the NGPA, the Federal Energy Regulatory Commission (FERC or Commission) promulgated regulations to allow for "self-implementing transportation" service. LDCs were allowed to secure transportation service for gas supplies purchased for LDC system supply and transported on interstate pipelines. Order Nos. 234-B(17) and 319(18) opened the door to increased use of theretofore rarely-used direct purchase arrangements by establishing procedures to facilitate quick access to interstate transportation by high-priority and other end-users.

[b]--Order No. 380.

Not long thereafter, FERC, in Order No. 380,(19) outlawed minimum commodity bills applied by interstate pipelines to LDC sales. Minimum bills required customers to pay pipelines for a minimum volume of gas each month (or year) whether or not the customer actually took that amount of gas.

In Order No. 380, the Commission announced its intention to eliminate minimum bills from a pipeline's tariff to the extent that these provisions permitted the recovery of variable costs. FERC determined that minimum bills had two negative effects upon the natural gas market: (1) Minimum commodity bills had become a vehicle by which enormous purchased gas costs could be collected even if the pipeline never incurred those costs; and (2) minimum commodity bills had become a major obstacle to the transmittal of clear market signals from the burner tip back to the wellhead.(20) Accordingly, in Order No. 380, FERC ruled that the collection of variable costs through a minimum bill represented an "unjust and unreasonable" rate under Sections 4 and 5 of the NGA.(21) Later, the Commission extended this prohibition to minimum take provisions.(22) These decisions set the stage for LDCs to engage in the same type of direct purchase transactions--"self help"--that were facilitated by Order Nos. 319 and 234-B.

[c]--Special Marketing Programs.

Under the NGPA, "new gas" (generally, gas from wells first producing in commercial quantities after April 20, 1977) was subject to constantly increasing price ceilings that would eventually reach a figure predicted to approximate the market price in 1985. At that point, the new gas was to be deregulated. Pipelines that had entered into long-term contracts with producers were locked into gas purchases at prices based on 1978 expectations. Unfortunately, 1978 predictions of the 1985 market were incorrect and the maximum lawful price for new gas had already reached or exceeded the market-clearing price in many areas.(23) As a result, pipelines in the post-Order No. 380 environment could not hold on to customers that could shift to alternative fuels cheaper than natural gas.

The departure of "non-captive" customers had severe consequences on the remaining customers. First, the fixed cost component of their rates went up because those costs were now allocated among a smaller number of rate payers. Second, the gas cost component of the rate skyrocketed because the pipelines' average gas cost per unit volume was increased by "take-or-pay" liabilities to producers.(24)

To alleviate this problem, Columbia Gas Transmission Corporation (Columbia) proposed a "special marketing program" (SMP) whereby it would (1) release its contract rights to specified gas, (2) transport the released gas to purchasers who would buy the volumes of released gas sold, and (3) the suppliers would
credit Columbia's take-or-pay liability with the volume of released gas sold. The certificate issued to Columbia to effectuate the SMP, among other things, limited customers who could purchase the released gas to those with alternative sources of fuel. FERC approved Columbia's SMP and authorized other pipelines to introduce similar programs.\(^{(25)}\)

The Maryland People's Counsel (MPC) questioned the validity of limiting those to whom sales could be made to non-captive customers. The limitation had the effect of preventing the system's captive customers from purchasing the cheaper released gas. On review, the District of Columbia Circuit invalidated the SMPs, ruling that the exclusion was invalid, in part because, by segmenting the regulatory market, pipelines were able to exploit to the maximum their monopoly power over consumers.\(^{(26)}\) Because the goal of the NGA is to protect consumers from exploitation by monopolistic pipelines, the court held that selective discounting of sales prices and selective transportation of gas violated the NGA.

[d]-Order Nos. 436/500/528.

In response to the \(MPC\) I decisions, FERC issued Order No. 436.\(^{(27)}\) Not long thereafter, Order No. 436 was described by the D.C. Circuit as envisaging "a complete restructuring of the natural gas industry."\(^{(28)}\)

The cornerstone of Order No. 436 was its nondiscriminatory access requirement.\(^{(29)}\) Any pipeline that accepted an open-access blanket certificate would, if space were available, have to ship gas for any shipper requesting service. Moreover, unlike under traditional Section 7(c) certificates or previous blanket programs, there was no time limit on the service, nor were there any source or market restrictions. Thus, Order No. 436 provided yet another tool for LDCs and end-users that wished to purchase gas from a supplier other than their traditional supplier.\(^{(30)}\)

While, at the time, Order No. 436 might have been considered the conclusive chapter in the story of developing competition in natural gas markets, it was not. Order No. 436 was merely a another, albeit large, step in a long journey, one that many foresee finally being completed in Order No. 636.

Reflecting now (with the benefit of hindsight) on Order No. 436, one might say that it had two major contributions to the restructuring now taking place under Order No. 636. By opening transportation to any prospective shipper, including LDCs, it allowed a vibrant spot market based on interruptible transportation to develop, exacerbating the take-or-pay problem. By failing to mandate the "unbundling" of pipeline merchant and transportation functions, it left the firm, long-term market in the hands of the pipelines, which alone controlled the necessary facilities to provide long-term firm service on peak days.

Ultimately, two distinct markets developed--a market for when there was slack pipeline capacity (the spot or interruptible market) dominated by non-pipeline suppliers\(^{(31)}\) and a market for firm supplies dominated by pipelines. Because pipelines needed much higher sales volumes than this bifurcated market allowed, given their higher than average cost of gas, they needed some way to assure that their customers would provide the revenue stream necessary to compensate producers to hold gas ready for them on peak days. (This concern had been taken care of in the past by minimum commodity bills.) On the other side of the equation, while the pipelines were the beneficiaries of control of the facilities (storage, line pack, and flexible receipt point access, among others) they paid for this privilege by being saddled with the obligation to provide service to their customers' maximum contractual entitlements on peak days under their sales certificates.\(^{(32)}\) In the end, increasing take-or-pay woes (and a remand by the D.C. Circuit)\(^{(33)}\) forced the Commission to look for "fixes" to its restructuring construct.

The first "fix" came in Order No. 500.\(^{(34)}\) There, FERC intended to address take-or-pay in a variety of
ways. Most prominent for purposes of Order No. 636 was to suggest that pipelines be able to impose Gas Inventory Charges (GICs). A GIC would allow a pipeline to collect a set amount for standing ready to provide gas on a peak day. In essence, it would be an "up front" take-or-pay charge.

Order No. 500 also proposed the "purchase deficiency allocation method" under which interstate pipelines could allocate to their customers the costs of settling take-or-pay liabilities with their suppliers; costs so allocated could be recovered through fixed charges. However, D.C. Circuit vacated and remanded the purchase deficiency method finding that it violated the filed rate doctrine.

Responding to the court's remand, the Commission issued its second "fix," Order No. 528. Order No. 528 did not prescribe a particular method for allocating take-or-pay costs. Rather, it outlined several principles that the Commission would use to evaluate revised allocation methods. By applying these suggested principles and by promoting settlement discussions aimed at resolving allocation of take-or-pay costs, the Commission hoped to put the take-or-pay problem behind the industry once and for all.

**[e]--Order Nos. 451/490.**

While the industry was struggling to adapt to the "open-access" environment initiated by Order No. 436, the Commission promulgated two additional rules designed to alleviate certain pricing distortions and to promote the efficient operation of market forces. Order Nos. 451 and 490 were designed to encourage market responsive pricing and enhance the availability of competitive gas supply. Ultimately, the Commission hoped that renegotiation up of low-priced gas would be coupled with downward renegotiation of high priced gas, resulting in market equilibrium.

**§ 15.03. Basic Elements of Order No. 636.**

While all these developments contributed to a massive increase in the number of "self-help" transactions in gas markets, they did not change the bifurcated nature of the market. Most firm sales continued to be made by pipelines at above-market prices and interruptible or spot sales were made by others at highly competitive prices. Order No. 636 promises to change this.

There are about a dozen basic elements of Order No. 636. Once these elements have been discussed, this chapter will turn to the role they will play in determining what legal relationships in the gas industry will look like once Order No. 636 has been fully implemented.

**[1]--Unbundling the Merchant Function.**

The cornerstone of Order No. 636 is the requirement that interstate pipeline no longer make "bundled" sales. After decades of certificating bundled sales, the Commission finds that the bundled merchant service operates "in a manner that causes considerable competitive harm to all segments of the natural gas industry" and amounts to an "unlawful restraint of trade." In turn, it finds continuation of bundled merchant service to be a violation of Section 4(b) and Section 5(a) of the NGA. As a result, pipelines are ordered to "unbundle" their merchant and transportation services and to offer each individually.

The "unbundling" process envisions that pipelines and customers will negotiate new market-based sales agreements, with respect to which customers may reduce their sales MDQs in whole or part. Unless the firm transportation rights associated with formerly bundled city-gate sales can be reassigned to others, the LDCs will remain responsible for assuming the costs of (and be entitled to use) their share of the facilities used to provide the bundled sales service. "Packaged" city-gate service can be made available where the
merchant (pipeline or otherwise) acts as agent for (or is otherwise delegated authority to administer transportation rights of) the purchaser. The agent could collect a negotiated fee, which would not be a jurisdictional rate. However, transportation components of this service would have to be separately stated.

While the Commission has ordered unbundling, the extent to which unbundling actually occurs is subject to differing interpretations. This takes on some measure of competitive significance. For now, the reader should focus on the fact that LDCs and other "city-gate" purchasers of gas will have available for purchase from different providers both firm transportation (along with all the components that made up the non-gas portion of a pipeline's bundled sales service) and the commodity being transported, natural gas.

[2]--Service Equality.

With only a few exceptions, if the pipeline merchant function must move gas to market using the same rates, terms, and conditions of service as its competitors, by definition, there should be fair and equal competition. The Commission, however, did not see fit to allow this axiom to work on its own. It specifically required that a pipeline not give its merchant function an advantage "through a tariff provision or otherwise," in matters relating to open-access transportation.

Notably, the Commission did not require what the pipelines' competitors and customers had been clamoring for a number of years--"comparability." Instead, it coined a new, stronger term--"equality."

The equality principle in Order No. 636 opens the door for examination of the impact of each tariff provision on various suppliers. The points of reference, however, could be between the pipeline, its affiliate, and independent suppliers, as opposed to between independent suppliers themselves. The equality requirement will also be subject to debate, particularly when viewed in relation to hints in the Order itself that certain aspects of the unbundling process could give the pipeline merchant function a significant advantage over other suppliers in terms of access to facilities.


Just as "equality" of access to facilities is deemed a critical factor in establishing a competitive firm gas-sales market, so is access to information regarding the availability of services. Because most pipelines are capacity constrained at peak times, capacity must be rationed. To date, the Commission has not called on pipelines to act as common carriers and allocate capacity pro rata among all parties requesting service. Historically, it has endorsed a "first come, first served" approach. Accordingly, being the first to know when capacity is available for contracting or use can be the functional equivalent of having priority access to the pipeline. Thus, the Commission requires pipelines to provide all shippers equal and timely access to certain information through the use of electronic bulletin boards.

In Order No. 636, the Commission set forth certain "minimum general standards" for the operation of electronic bulletin boards. Presumably, these standards will not only allow for easy access to information about capacity availability, but also to information necessary to recognize that any untoward activity is occurring with respect to capacity allocation and pricing.

[4]--Market Centers/Pooling.

A number of commenters on the proposed rulemaking that preceded Order No. 636 advocated that the Commission set minimum national standards for certain operating parameters. These commenters took the view that different tariff provisions on each pipeline could frustrate pipe-to-pipe transactions and limit the
availability of supplies to serve particular markets.

In Order No. 636, the Commission refrained from demanding uniform, generic operating standards. Nonetheless, it did prohibit implementation of tariff provisions that would preclude development of market centers. It also stated its intent that "only legitimate and reasonable operational conditions" be applied and be specifically spelled out in tariffs after sufficient advance notice. (57)

Notwithstanding its decision not to implement generic standards, the Commission nonetheless "reemphasizes . . . its regulations that pipelines allow shippers to have flexible receipt and delivery points" and goes on to require that flexibility be granted. (58) Within a customer's service area, flexible delivery point policy would have to mirror the pipeline's production-area flexible receipt point policy. Otherwise, within-path (59) flexibility will be required (on an interruptible basis at the particular alternative point) as to both receipt and delivery points.

[5]--Storage.

Gas is produced at a relatively steady flow rate. Thus, in order to meet fluctuations in demand from season to season and day to day, gas is injected (most often in the summer) into storage facilities for withdrawal during peak periods. One of the reasons often cited for LDCs not having exercised their Order No. 436-based CD conversion rights was that the conversion process only gave the LDCs firm transportation rights, when, in contrast, many pipelines rely heavily on storage to meet peak-day requirements. (60)

Responding to this problem, the Commission amended its regulations to define "transportation" as including storage. (61) As a result, interstate pipelines will have to offer nondiscriminatory access to storage, both on a day-to-day basis and during the unbundling process. Some storage can be retained for load balancing and "no-notice" service, but unbundled storage must be offered. (62) "Upstream" storage can be assigned, and stranded storage costs collected as transition costs. (63)

[6]--Access To Upstream Facilities.

The pipelines traditionally have depended on more than firm transportation to provide bundled city-gate sales service. Often, they have contracted with third-party--"upstream" or "off-system"--pipelines and storage facilities to provide firm access to supplies not directly attached to their systems.

Under the Order No. 436 construct, pipelines were not required to provide converting customers access to anything but firm transportation on their own systems. Thus, in trying to duplicate the pipeline's merchant service with an alternate supplier, LDCs were often left without firm access to off-system supplies. (64) In addition, because capacity assignment and brokering programs were not widely available and, in any event, temporary, pipelines could not readily assign upstream rights to their customers.

In Order No. 636, the Commission not only authorizes, but requires, open-access pipelines to provide firm shippers non-discriminatory access to firm transportation and storage capacity (but not to exchanges, interruptible transportation, or rights on intrastate facilities) held by them on upstream pipelines. Assignments must be permanent. (65) As is the case with many other details of implementation of Order No. 636, the mechanics and allocation aspects of assignment are left to restructuring proceedings. Upstream capacity not desired by customers on downstream pipelines could be released (under the programs discussed immediately below) or paid for as a transition cost. (66)

[7]--Capacity Reassignment/Brokering.
The immediately preceding discussion speaks primarily to LDC access to a pipeline's capacity on another pipeline and how that capacity would be made available to the capacity holder's customers. In Order No. 636, the Commission also sets that stage for customers of LDCs (67) (or others) to obtain access to capacity on the pipeline serving the LDC.

Order No. 636 authorizes a new firm capacity reallocation program. Firm shippers can release unwanted capacity to those desiring capacity. Capacity can be released temporarily or permanently. It can also be released subject to condition (e.g., on an interruptible basis). Release offers would be posted on a bulletin board system (BBS). Offers brought to the pipeline could be bettered by bidders using the BBS, but parties to offers brought to the pipeline by the releasing party--"pre-arranged deals"--would have a right of first refusal. (68)

Unless the pipeline agrees, the original shipper remains "liable on its contract" (69) but otherwise the new shipper steps into the shoes of the releasing party. Pipelines can post their own available capacity on the BBS so that buyers may choose between pipeline and others' capacity. (70) Specific terms of the programs, including any fee the pipeline might be entitled to recover for out-of-pocket administrative expenses, would be determined in restructuring proceedings. If a pipeline actively and successfully markets released capacity, it may collect an additional agreed-upon fee. (71)

Rates for reassigned capacity cannot exceed the maximum rate for the capacity being released. If long-haul capacity is picked up for a short-haul, however, the long-haul rate could be applied. (72)

At the time Order No. 636 was issued, several pipelines had already received approval for experimental capacity brokering programs. With the issuance of Order No. 636, the Commission modified (73) all existing capacity brokering certificates.

[8]--No-Notice Service.

In the rulemaking process leading up to the issuance of Order No. 636, many pipelines and LDCs argued that unbundling the pipeline merchant function would deprive LDCs of the "no-notice" service they could call upon to receive firm supplies up to their full MDQ on any day. (74) After holding a technical conference attended by all of its members, (75) the Commission concluded that, given sufficient operational control, the pipelines could provide "no-notice" service based on firm transportation.

Thus, the Commission will require pipelines that make bundled sales on the effective date of the rule to provide non-discriminatory "no-notice" firm transportation service. This service, details of which would be developed in RS proceedings, will allow customers to take up to their MDQ without daily penalty and will be in addition to the firm transportation service now available. In creating the service, the Commission makes the commitment to "ensure that the pipeline is not attempting, through the 'no-notice' transportation service, to simply replace one form of bundled service with another anti-competitive service." (76) It also makes several statements to the effect that it will be a champion against degradation of existing unbundled services and discriminatory operating conditions. (77)

While refraining from mandating the parameters of no-notice service, the Commission states that parties must recognize that pipelines may need to issue flow and injection orders, have predetermined allocation arrangements, retain storage rights, and enter into agreements for the diversion of supplies flowing under interruptible agreements. These are discussed in more detail.

[9]--Straight Fixed-Variable Rates.
In the period leading up to Order No. 636, two forces combined to change the structure of firm pipeline rates. One was the perception that firm capacity was being hoarded or, alternatively, simply underpriced. The other involved competition from Canadian supplies, which were alleged to be competing unfairly with U.S. production, based on the use in Canada of the straight fixed-variable (SFV) method of cost classification.\(^{(78)}\)

In Order No. 636, the Commission adopted SFV as its standard method of cost classification for the purpose of billing firm transportation customers. The Commission, however, noted that it "will not rigidly preclude the pipeline, its customers . . . and others from agreeing to an alternative method that deviates from SFV and may be appropriate to that particular pipeline system."\(^{(79)}\) Those proposing deviations from SFV will have a "heavy burden of persuasion."\(^{(80)}\) Rates for interruptible transportation and other billing conventions, such as mileage-based rates, will continue to be decided with reference to the Rate Design Policy Statement\(^{(81)}\) on a case-by-case basis.

In an attempt to avoid sharp cost shifts, the Commission required pipelines to submit a study of costs by customer class under SFV versus the existing rates. If costs shift more than 10\%, a phase-in of up to four years will be provided.\(^{(82)}\)

[10]--Blanket Pipeline Sales Certificates.

By requiring that pipelines unbundle their firm sales and transportation services, the Commission did not intend to put pipelines out of the business of selling gas.\(^{(83)}\) To the contrary, in Order No. 636, the Commission facilitated the development of a pipeline merchant function that, for the first time, would be allowed to sell gas at a price not calculated to be its purchase price, indeed, to make a profit. In doing so, the Commission issued a blanket sales certificate to all pipelines presently offering sales service. This will allow these pipelines to make unbundled firm and interruptible sales on a comparable basis with unregulated merchants, i.e., at market rates.\(^{(84)}\)

Parties are free to try to show that market-based sales rates are not appropriate because of the lack of market competition. Existing interruptible sales certificates (which allowed pipelines to sell gas in excess of their firm needs on an interruptible basis) will be subsumed by the new certificates.\(^{(85)}\) Once the new certificates are activated, Purchased Gas Cost Adjustment (PGA) mechanisms under which gas costs and revenues were reconciled will be eliminated.\(^{(86)}\) While, due to statutory requirements, pipeline sales will still technically be regulated, pipelines will have to report only aggregate sales data on an annual basis.\(^{(87)}\)

[11]--Transition Costs.

As is the case with virtually any restructuring, there will be "transition costs" associated with the restructuring envisioned by Order No. 636. As many take-or-pay related costs and costs of opening pipelines to numerous third-party shippers had already been recovered by the pipelines, both the breadth of costs and the appropriate level of pipeline recovery (or cost "sharing") were hotly debated in comments on the Notice of Proposed Rulemaking (NOPR) which preceded Order No. 636.\(^{(88)}\)

Ultimately, FERC decided to let pipelines recover fully all prudently incurred transition costs. PGA balances can be direct billed.\(^{(89)}\) Gas supply realignment costs--costs of buying out and buying down (to market) existing gas contracts--may be recovered via an "exit fee," firm transportation reservation charge, surcharge, or other similar method.\(^{(90)}\) In the hopes of minimizing gas-supply-related transition costs, FERC strongly encourages assignment of existing gas supply contracts from pipelines to LDCs.
As pipelines reduce their purchase contracts, there will inevitably be some overlap between historical take-or-pay costs that would have been incurred regardless of the issuance of Order No. 636 and Order No. 636-derivative costs. Because take-or-pay costs recovered under Order No. 528 require some absorption by the pipeline and those incurred under Order No. 636 do not, the Commission stated its intent to differentiate between restructuring-based costs and other realignment costs.\(^{(91)}\)

Stranded costs and new facilities costs will be recovered through traditional Section 4 rate case treatment.\(^{(92)}\) Notably, the Commission indicated a willingness to consider demand-charge relief to LDCs in bypass situations.\(^{(93)}\)

\[12\]--Standards Of Conduct.

With the advent of open-access under Order No. 436 and the lingering of cost-based, weighted average rates for pipeline gas sales, many pipelines formed marketing affiliates to compete for spot sales. Unlike the firm long-term market, which was priced in a relatively stable manner using a portfolio of both high and low-priced gas, spot sales competition was highly competitive and prices were volatile in the period following the issuance of Order No. 436.

As spot prices declined, the gap between pipeline system supply prices and spot prices increased. Because pipelines were required to make sales at their weighted average cost of gas (WACOG), they could not compete for spot sales in the post-Order No. 436 world. To stay in the market (and also to move volumes that they were required to purchase but were otherwise susceptible to negotiated release by producers) many pipelines formed marketing affiliates.

These affiliates were not constrained as to the price at which they could sell gas. Thus, they could not only compete in the spot market, they could also make a profit.

It was not long before complaints were lodged against pipelines for favoring their marketing affiliates by, \textit{inter alia}, giving them information not generally made available to the public.\(^{(94)}\) FERC issued Order No. 497,\(^{(95)}\) which provided standards of conduct and reporting requirements applicable to the relationship between pipelines and their marketing affiliates.\(^{(96)}\)

Once it became apparent that pipelines were to be freed from cost-based gas pricing restrictions, it also became accepted that they would have the same incentive to favor their own merchant functions as they had to favor their marketing affiliates. Therefore, in Order No. 636, the Commission applied the Order No. 497 standards and reporting requirements to the pipeline merchant function "by considering their sales operating employees as an operational unit which is the functional equivalent of a marketing affiliate." The pipeline merchant function will have to be separated along organizational lines to the maximum extent practicable; cost justifications will have to be provided in order "to ensure that the cost of providing each unbundled service can be identified and assigned to such service."\(^{(97)}\)

\[13\]--Pre-granted Abandonment.

One aspect of "comparability" that was often cited as critical in LDCs' decisions not to convert firm sales to firm transportation under Order No. 436 revolved around the relatively arcane concept of abandonment.\(^{(98)}\) Under the NGA, once a pipeline performed a jurisdictional service for a customer, it could not terminate (abandon) that service without prior Commission approval pursuant to NGA Section 7(b).\(^{(99)}\) Under Order No. 436, however, the Commission "pre-granted" abandonment of open-access transportation service,\(^{(100)}\) so that the pipeline had no need to go to the Commission to seek authority to terminate services at the end
of a contract. Thus, in converting from traditional sales service to firm transportation under Order No. 436, an LDC would go from having service under a contract that required obtaining abandonment authority to one that would allow the pipeline to terminate service without approval at the end of the service agreement.

Order No. 636 authorizes continued pre-granted abandonment of interruptible and short-term (one year or less) firm transportation at the expiration of the contract. Pre-granted abandonment is also provided for unbundled firm and interruptible gas sales service, again, at the expiration of the contract. As to long-term firm transportation service, however, a customer may avoid pre-granted abandonment contractually or by exercising a right of first refusal, agreeing to pay the highest rate, up to the maximum rate to the existing customer's delivery point, for the same term as a competing offeror.\(^{(101)}\)

Here, too, the specific mechanics of evaluating offers will be left to the restructuring proceedings. Offers for part of the existing capacity must be matched if the existing holder wants to retain that capacity.\(^{(102)}\)

\section*{15.04. Restructured Services.}

In the following portions of this Chapter, we attempt some predictions of what the gas industry will look like after the restructuring required by Order No. 636. Of course, reshaping an industry will involve not only the redefinition of many existing relationships but, also the development of new business relationships. Both will require corresponding legal documentation. We will not attempt here to describe the specifics of those relationships but, instead, try to familiarize the reader with the possible structures that might arise, and, in many instances, point to analogous legal relationships already in use in the gas industry that might be helpful points of reference for drafting provisions to address the new industry structure.

\[1\]--Sales.

In contrast to the current structure, where a pipeline offers a limited menu of gas sales services to its customers, pipelines will be free to negotiate gas supply contracts specifically tailored to the needs of each customer. Today, many LDCs with different load factors, peaking needs, and other requirements may be served under the same sales rate schedule. Future sales contracts can be negotiated to suit individual customer needs. This could mean that some customers, most likely those with low load factors, will experience cost increases, while others will reap the benefits of the efficiencies inherent in their usage profiles.

One of the perceived advantages of the pre-restructuring system was that diversity of usage on any pipeline system inured to the benefit of all customers. Where there were not offsetting benefits, those whose load profiles were less expensive to serve subsidized those with more expensive load profiles.

Whether the advantages of diversity can be captured in the new environment is subject to debate. On one side, an argument can be made that there will be competition for the most cost-efficient markets to serve and all the benefits of diversity will flow to customers with the smoothest load profile, leaving those with peaks and valleys to pick up the costs of "on demand" service.

On the other side of the debate are those who argue that the benefits of diversity will flourish. This would occur as a result of nationalization of the pipeline grid, allowing access to cross pipeline diversity.\(^{(103)}\) Rather than a single aggregator of supply using a limited set of facilities to serve markets on its pipeline, future aggregators will be able to utilize the systems of numerous pipelines, extending the reach for diversity beyond the facilities of the pipeline serving the LDC to a web of interconnected pipelines. Thus, as a weather front passes across a region served by a number of pipelines, the aggregator can schedule its supply to follow usage across those pipelines, rather than having to swing the supply up on the individual pipeline, then swing it back down when the front passes. This should result in higher load factor deliveries for
suppliers, perhaps providing price incentives to offset one-system diversity losses.

Of course, regaining and enhancing diversity benefits will face numerous obstacles, including individual pipeline rate design, scheduling and imbalance procedures, to mention a few. Tracking this flexibility in gas supply and purchase contracts will require innovative contract drafting, as prices vary from region to region and the responsibility for getting gas into any of number of pipelines changes on a moment's notice.

Finally, diversity benefits should be regained by allowing pipelines to serve both firm and interruptible sales customers flexibly. To the extent interruptible load can be served in off-peak periods, load factors will again be enhanced for producers. To the extent pipeline certificates allow off-system sales, even more flexibility benefits should be derived for those who wish to purchase from pipelines. As pipelines look at these benefits as business opportunities, they may influence other pipelines to provide rate and tariff structures that facilitate the use of flexibility inherent in other pipelines' systems as well as their own.

[a]--Negotiated Pipeline Sales Contracts.

Pipelines will be free to negotiate individually tailored sales contracts with their customers. This does not mean, however, that they will be free from NGA restrictions. As pipelines are not "first sellers" under the NGPA, their sales still must be certificated, and are subject to proscriptions against undue discrimination. While FERC is relying on a competitive gas commodity market to police gas sale price, term, and condition discrimination, total abdication of that role to the market will require amendment of the NGA. In the absence of an amendment, pipelines must be prepared to face challenges to their individual negotiating strategies if those are viewed as overreaching. Thus, while compared to today's tariff-based agreements, post-Order No. 636 sales agreements with pipelines will be freely negotiated, this freedom is not yet total.

[i]--Filed Rates/Confidentiality.

One measure of freedom, however, is that the pipeline will not be required to file their new gas sales agreements with FERC, nor will they have to post rates. This will make it more difficult to prove discrimination in pipeline sales negotiations. However, it is thought to keep the pressure on price competition by not having the pipeline price serve as a target for all competitors.

[ii]--Downstream Flowthrough by State

Regulatory Commissions.

One of the advantages traditionally enjoyed by a pipeline merchant over its competitors was that its purchases from an interstate pipeline were not subject to review at the state level. In essence, a FERC prudence decision flowed through to the state level.

In the future, all LDC purchase decisions will be subject to state-level prudence reviews. This, in turn, will give new importance to contract provisions relieving purchasers of their duty to purchase if their purchase gas costs cannot be passed on to downstream (in this case, end-use) customers. While these contract provisions were often found in agreements between interstate pipelines and their suppliers, they should now find their way into LDC-supplier agreements. In turn, state regulatory commission policies will take on an increasingly important role in gas contracting, a role suppliers must be prepared to monitor, as a business matter and, as a legal matter, to anticipate and resolve.

[b]--Point of Sale or "Unbundling."

In Order No. 636, FERC requires pipelines to move their point of sale upstream of the city-gate, thus
"unbundling" their sales and delivery services. FERC also allows pipelines to "repackage" service by, for instance, being assigned customers' rights to firm transportation and storage agreements. By acting as agent for the administration of those agreements and by selling the gas commodity, a pipeline (or other merchant) could recreate the city-gate service of old.\(^{108}\)

The precise location of the point of sale will have an impact on the price of gas (reflecting the extent to which it includes costs of upstream facilities needed to get it to the point of sale) and the availability of services (e.g., upstream gathering) for others to use. FERC did not mandate the precise location of the point of unbundling, leaving this as an issue for restructuring negotiations.\(^{109}\)

Just how big an issue this will be is yet to be seen. If a pipeline has traditionally "bundled" its gathering costs in its transportation rates, has committed supplies on its gathering systems, and intends to remain in the merchant function, its point of unbundling is likely to be at the intersection of its gathering system and receipt point into the mainline system.\(^{110}\) Of course, simply "unbundling" gathering rates will undo the economics of this advantage-creating arrangement, but the FERC has not required this unbundling on an across-the-board basis. From a practitioner's perspective, the possibility of these rate changes, among others, must be factored into negotiations for the delivered price of supply.

[c]--Discounts Associated with Pipeline Sales.

Prior to Order No. 636, many pipelines used discounted sales programs to shed excess supplies. Numerous issues arose concerning those programs, among them questions about the treatment of discounts provided with the pipeline sale. If a pipeline was able to purchase supply at a $1.50, its transportation rate was $0.50, and the pipeline agreed to deliver the gas at a citygate for $1.95, could it be deemed to have provided a 5-cent transportation discount, bringing the sale within the rules for Part 284 transportation requiring pipeline transportation discounts be provided on a non-discriminatory basis?\(^{111}\)

In cases decided before unbundling, FERC required pipelines to offer "correlative" transportation discounts to those who preferred to purchase their gas from a non-pipeline supplier, as opposed to purchasing the pipeline's gas.\(^{112}\) It was not long before complaints arose that pipelines stated that they were discounting gathering services, as opposed to transportation, and if the alternate supplier was not using the same gathering system there would be no correlative discount. Some time later, FERC established a "transportation first" discount rule where any discount from the total price of gas delivered to the city gate was to be considered a discount first from the transportation component, then from other components. This prevented pipelines from characterizing discounts in a manner that allowed them to avoid the correlative discount rule.\(^{113}\)

Later still, FERC found that, if the pipeline unbundled its discounted sales service, it did not have to offer a discount unless it was offering a discount on the transportation component of the sale.\(^{115}\) The same issue will remain in the post-restructuring era. However, the ability to track discounts from sales prices will be lost when rates are not posted. Nonetheless, the Commission has specifically required pipelines offering discounts for services related to a pipeline merchant sale to offer those same discounts contemporaneously to others.\(^{116}\) With a new definition for storage, the reach of this provision will now encompass storage as well as traditional transportation.

[d]--Order No. 497.

The Commission has applied the Order No. 497 reporting and organizational separation requirements to pipeline merchants, as well as to their marketing affiliates. Similar issues to those under the Order No. 497
context are sure to arise.

The Commission is attempting to require arm's-length dealing between the divisions, but could not see its way clear to order full separation. Thus, there will likely continue to be debates over the effectiveness of the rule, with proponents of full separation pointing to obvious areas where information could be shared to the advantage of the pipeline merchant function, and pipelines pointing to efficiencies associated with integration. While these debates are not likely to result in major changes to the rule, we may see the pipelines ultimately getting out of the merchant function altogether, or consolidating merchant functions in the marketing affiliate.\(^{[118]}\) Thus, when entering into an agreement either to buy from or sell to a pipeline merchant, one would be well advised to review closely provisions dealing with assignments and successions of interest.

\[2]\text{-Firm Transportation.}\]

When "unbundled," the delivery component of a pipeline's bundled sales service will most often be comprised of firm transportation rights, along with lesser amounts for associated storage, line pack, upstream transportation, and the like. In the unbundling process, these rights must be defined, and then allocated.

Defining firm transportation rights is not an easy task. Most pipelines are not so constructed that, for each MMBtu of delivery capability at a city gate, there is a corresponding MMBtu of rights from a receipt point straight through to the delivery point. Instead, most pipelines have production area receipt capabilities that are multiples of their delivery capability.\(^{[119]}\) Thus, LDCs will need to be involved in the definition process at the outset to assure that rights they consider essential are among those to be allocated.

\[a]\text{-Capacity Allocation.}\]

Once the allocation rights are defined, the allocation process can move forward. Fortunately, we do have some guidance on how to allocate firm transportation rights. There are a number of models in use today.

One model involves the \textit{pro rata} allocation of rights, generally without assigning specific volumes to individual facilities. Rather than receiving a set allocation at individual receipt points and pipeline segments, an LDC is assured only of a \textit{pro rata} share of the nominations at each constrained point.\(^{[120]}\) An advantage of this system is that LDCs are not required to secure supplies in small increments in order to utilize a \textit{pro rata} share of a small receipt point. It also avoids the necessity to set a specific maximum right for customers who have never had such a right, i.e., those customers who were entitled to rely on the pipeline to fulfill whatever requirements they had.\(^{[121]}\) The disadvantage of this system is that entitlements may differ from month to month depending on who else is nominating supplies at a given point.

Another model involves establishing specific entitlements through predefined mainline constraint points, without establishing specific receipt point entitlements.\(^{[122]}\) Capacity allocation upstream of the constrained points is generally not necessary, because upstream of those points the pipeline has the capacity to serve all upstream deliverability needs. This model has the advantage of certainty through the constrained points and flexibility upstream of them.

Another model proposed in the restructuring process involves allocating capacity at every point on the system and assigning an allocated share to each LDC.\(^{[123]}\) This assures that each point is covered but leaves the system so fragmented that it would be virtually impossible to aggregate supplies. The proposed answer to this dilemma is twofold: First, define the right as a minimum right, with a preferential right to use any
point when no one else nominates it. Second, allow LDCs to trade capacity entitlements to aggregate useful capacity. Whether this method will be accepted is not yet known. The preceding two methods, however, have the advantage of being relatively successful in practice.

No matter what allocation method is proposed on a given pipeline, it is imperative that the scheme be established during, or preferably before, supply contracts are negotiated. If, for example, there is the possibility that gas coming out of a basin where supplies are cheap may be pro rationed, this will force either curtailment or substitution of more expensive supplies. Both parties to the contract need to cover these eventualities in advance, not on the coldest day of the year.

[b]--Changes to Existing Service That May Be Necessary to Implement the Requirement That Quality of Service Be Maintained.

Order No. 636 requires that there be no dilution in the quality of service offered LDCs as a result of unbundling. (124) This could require changes in both existing services and certain operational provisions. Likely candidates are scheduling imbalance tolerances and nominations deadlines, particularly for interruptible transportation and for services not in the "no-notice" category. It is likely that "inferior" services will become more inferior to make the superior services more reliable. Again, when executing supply arrangements, it will be essential to know the parameters in which the buyer and seller must operate. If, for example, a buyer wants to rely heavily on a cheaper, non-no-notice service, it must be able to handle unanticipated swings in demand so as to avoid scheduling or imbalance penalties. This could be accomplished by using storage, which involves an additional cost. Who must administer that storage and bear its costs will become more important than ever in contract negotiations. (125)

[3]--Storage.

The same problems arise in defining and allocating storage rights as with firm transportation rights. Storage rights, however, are even more difficult to define because they involve constantly changing rights. Unlike transportation, which can be likened to movement through a straw, storage is more like a balloon. It is easier to inject massive quantities of gas when the storage facility is nearly empty, and more difficult when it is nearly full. Conversely, it is easier to withdraw large quantities when the storage facility is full than when it is nearly empty. Thus, the rights to be allocated are fluid.

Defining storage rights becomes an exercise in setting thresholds at which rights to inject or withdraw change. The more tightly these rights are defined, the less flexible the service; stringent definitions necessarily result in a loss of diversity benefits. In addition, pipelines have contended, in early restructuring proceedings that they use their merchant function to "backstop" storage operations. In other words, when pipeline storage inventories are depleted too rapidly early in the withdrawal season, pipelines have purchased extra gas to restore the levels. Now that pipelines will have an economic incentive not to purchase additional gas during the withdrawal season, when prices are high, they will likely resort to tighter definitions of storage rights to assure that they can perform promised storage services.

[a]--Allocation of Capacity.

The process of allocating storage rights will likely be contentious. Simple pro rata allocation will hurt those with highly volatile needs, while those with steadier load factors could end up with more storage than they need. Because storage can be used, not only for operational needs, but to arbitrage seasonal peaks and valleys in prices, there will be little incentive for anyone to give up storage rights. (126)
Another allocation issue involves whether particular storage facilities will be allocated as if they were individual facilities or a single storage facility. If the individual facility approach is adopted, customers will be able to use firm storage and transmission rights on a given pipeline in conjunction with rights on another pipeline to gain maximum efficiencies. Conversely, if a pipeline treats an entire set of storage facilities as a single facility (and, in so doing, establishes a fictitious injection and withdrawal point) off-system supplies are less likely to be able to use the storage economically. Once again, these factors must be considered when entering into post-restructuring supply agreements.

[b]--Open-Access Contract Storage.

A question that must also be raised is whether storage is just that, and no more, or includes transportation rights to and from, or to or from, storage. In the past, FERC authorized open-access contract storage under separate rate schedules and certificates from open-access transportation. This resulted in transportation charges being assessed for movements both into and out of storage. With the redefinition of "transportation" to include storage, this economic anomaly may disappear. Transactions that relied on storage may have to be renegotiated. Those dismissed earlier because of costs may bear a second look, depending on how the pipelines react to this change. One thing that is likely to disappear is the doubling up of transmission charges associated with shipments in and out of storage, particularly where the storage is located on the mainline and the same pipeline is not being used twice.

[c]--Maximum Unbundling vs. Operational Needs.

Order No. 636 allows a pipeline not to unbundle and allocate all its storage facilities but, instead, to choose to retain some storage for "operational" needs. Operational needs will vary from pipeline to pipeline. Who has access to the operational flexibility provided by retention and the extent of flexibility will be major issues, pitting those who need flexibility (and may or may not be willing to pay fully for it) against those who do not (e.g., those with their own storage). These issues, as much as operational issues, will affect the economics of particular supply options.

[d]--Load Balancing Service.

One potential service that could result from the new focus on storage is load balancing. This could take many forms, but at a general level would likely involve the pipeline reserving storage in order to provide a service allowing shippers to avoid imbalance and scheduling penalties through automatic injections into and out of storage. Others may provide the supply to back up this service.

[e]--Limits On Use (e.g., Cycling Requirements).

Storage unbundling will involve defining rights in a manner heretofore largely unwarranted. It is highly likely that storage customers will face limits on injections and withdrawals based on individual (and, perhaps, collective) storage levels. In addition, customers may be required to maintain given inventory levels during certain times of the year, so that they fully cycle their storage rights over the course of the year. These, in turn, can impact takes under a panoply of LDC purchase agreements, even those not directly linked to storage.

[4]--"No-Notice" Service.

While FERC has required pipelines to provide a "no-notice" service option, defining just what that service is has proved difficult. FERC's definition envisions the customer being able to take gas on any day, up to its
maximum contractual rights, without penalty. This does not answer such questions such as whether the service is strictly a facilities-based service (requiring the customer to have gas in storage or otherwise available at a moment's notice) or whether it includes gas.\(^{(133)}\) Assuming the former, can a pipeline require that gas be in its storage facilities, rather than in third-party storage attached to the pipeline? Could a customer find supplies by diverting supplies destined for an interruptible customer by mutual agreement?

Just what "notice" might be required for no-notice service is also the subject of debate. Texas Eastern Transmission Corporation has proposed that penalties apply unless the no-notice shipper calls the pipeline to advise it of changes in takes.\(^{(134)}\) Can a pipeline require customers to have no-notice service on an upstream pipeline in order to secure the same service on its system?\(^{(135)}\) Must a customer convert to only no-notice service, or can it also convert to firm transportation for a portion of its needs?

These and a host of other issues surrounding the development of no-notice service are coming to the fore. Before entering into a supply agreement that relies on no-notice service, both suppliers and their customers must have a firm grip on the parameters of the service they will use.

[5]--Gathering/Production Area Services.

Many pipelines own facilities upstream of their mainline. These can include gathering, processing, and storage facilities. These facilities, particularly gathering, might have been constructed as part of the pipeline and included in the pipeline's rate base, even though, technically, not subject to FERC jurisdiction. How these facilities are treated in the restructuring process will affect their availability and pricing, ultimately impacting transactions that rely on them.

[a]--Unbundling: Rates.

One of the most hotly debated restructuring issues will be whether gathering facilities and services are unbundled from transportation services. Order No. 636 does not require unbundling of gathering from transmission rates. Instead, it leaves this and other related issues to the Rate Design Policy Statement.\(^{(136)}\) The bundling of gathering and transmission services results in a subsidy to those who use bundled gathering while forcing those who do not, yet use the pipeline's transmission service, to pay for something that they do not receive. Whether to require unbundling is an issue for which rehearing of Order No. 636 has been requested. In many instances, the ultimate outcome will have a substantial impact on the economics of existing and future transactions.\(^{(137)}\)

Assuming that gathering rates are separately stated and services are unbundled,\(^{(138)}\) the next question for parties to restructuring will be how to accomplish this. Should costs be allocated and rates designed for each of the many gathering systems a particular pipeline might own, or should they apply to all pipeline-owned systems?\(^{(139)}\) Should there be firm reservation charges, or should the past practice of charging only a commodity rate for volumes actually gathered be continued?\(^{(140)}\) Until these issues are resolved, setting a firm price for supplies at a point downstream of a pipeline-owned gathering system will be difficult.

[b]--Reservations For Pipeline Merchant Service?

The foregoing discussion assumes that access to gathering systems owned by the pipelines will be widely available. However, in Order No. 636, the Commission allowed pipelines to reserve some upstream storage capacity for their own merchant functions.\(^{(141)}\) Whether the Commission intended also to allow reservations of gathering capacity for the pipeline merchant is unclear. As the restructuring process involves negotiation and compromise, those drafting supply arrangements that assume the availability of firm access to a pipeline's gathering systems would be well advised to validate those assumptions.
[c]--Reclassification.

Unbundling gathering rates may result in uneconomic rates for certain gathering systems. One method of easing the associated dislocations (and, perhaps, creating other competitive dislocations) is to "reclassify" gathering facilities as "transmission."(142) In effect, reclassification allows gathering facilities to remain "rolled-in" to transportation rates. Ironically, with the Commission allowing larger and larger facilities to be classified as gathering for jurisdictional purposes,(143) the move towards classifying relatively smaller gathering lines as "transmission" lines will appear incongruous. Whether the Commission will allow for different rate versus jurisdictional results is unclear.(144)

[d]--Sales of Facilities.

Some pipelines have taken to selling their gathering systems.(145) This may eliminate problems associated with unbundling and rates as part of the restructuring process per se, but it will not make those problems disappear. For the most part,(146) they will be shuffled out of FERC jurisdiction to state authorities, which may or may not act to resolve them.

[6]--Upstream Capacity.

Order No. 636 requires pipelines to provide firm shippers with non-discriminatory access to firm transportation and storage capacity (but not to exchanges, interruptible transportation, or rights on intrastate facilities) held by them on upstream pipelines. The mechanics and allocation aspects of assignment are left to restructuring proceedings.

Once again, access to upstream facilities may be a critical assumption underlying suppliers' plans to serve particular markets. While it is clear that the downstream pipelines must provide access to their upstream rights, it is less clear how this will happen. For instance, may a pipeline allow preferential access to customers who also assume upstream supply contracts? In light of the Commission's encouragement of these assumptions,(147) it could logically be argued that this is reasonable. May a pipeline reserve upstream capacity for its own use, either for merchant service or system operational needs?(148) Here, too, those entering into supply agreements must monitor restructuring proposals, as these proposals could have a profound impact on their ability to consummate their transactions as expected.

If, conversely, a pipeline wants to, but, due to lack of interest on the part of potential assignees, cannot assign upstream capacity, FERC assumes that it will treat that capacity as a "stranded cost" for Transition Cost recovery purposes. Order No. 636 does not directly address how this will occur. Presumably, the cost will be flowed through to those paying Transition Costs and the capacity will be made available as if it were part of the pipeline's system. This will give rise to questions regarding capacity allocation similar to those already mentioned regarding firm transportation.

[7]--Small Customer Transportation: Mitigating the Impacts on Small Customer.

Small customers concerns have long occupied the Commission's attention as it tried to move to a more market-based allocation of capacity rights and to deal with the allocation of costs associated with the Order No. 436 transition.(149) These concerns once again manifest themselves in Order No. 636, where the Commission requires that pipelines perform analyses to determine the impact of shifting to SFV rate design.(150)
Numerous suggestions have been made to mitigate the impacts of both the SFV rate shift and operational constraints that might be put in place system-wide. Generally, these are less easily met by small customers, who might have neither the staff that larger customers do to schedule and monitor flows, nor the facilities, e.g., storage and peak shaving, to act on what information they may be able to monitor.

As for the SFV rate shift, the Commission has suggested planning a four year phase-in of rate increases. An alternative presented early in the restructuring process is a permanent one-part, commodity-only firm transportation rate designed at a specified load factor. Absent mitigation, it will be essential for small customers to be able either to reassign capacity on a short-term basis, or to have someone else use their capacity in a manner that creates the same effect as being a larger customer.

Other suggestions for making restructuring more palatable to small customers include granting them greater imbalance and scheduling penalty tolerances than larger customers. This is generally accomplished by stating tolerances as "the greater of" a percentage of nominations or a flat number. In addition, allowing imbalance trading among shippers will help small customers as well as larger ones.

**[8]--Interruptible Transportation.**

An often-asked question is whether, in light of capacity reassignment, there will be any interruptible transportation available. If those who argue that there will be none are correct, debates over allocating costs to interruptible transportation service and whether interruptible rates are the equivalent of 100% or some different percentage load factor usage of firm rates will largely be moot. If the other side--which envisions a still vibrant interruptible transportation market--is correct, one can expect to see a protracted debate on these issues. Unfortunately, Order No. 636 provides no guidance on these matters, except to leave their resolution largely under the auspices of the Rate Design Policy Statement. We expect to see many creative ideas on how to deal with these issues, including not allocating any costs to interruptible transportation, instead crediting revenues from that transportation to firm shippers (with possibly the pipeline sharing in the revenues). These issues will arise concurrently in the context of structuring capacity release programs; a flexible release program will likely limit the use of interruptible transportation, while a more structured program, e.g., one with longer lead time, will result in more resort to interruptible transportation on a day-to-day basis.

**[9]--Backhaul Transportation.**

As with interruptible transportation, the Commission largely leaves the design of backhaul rates to the Policy Statement. Because they can "create," at little, no, or, negative costs, capacity that is essentially firm but can be purchased when needed, backhauls are increasingly becoming a tool of choice for aggregators moving gas on a variety of pipelines. Thus, rates for backhaul transportation will impact the ability of aggregators to tap system-to-system diversity benefits. While the Commission did not require that low backhaul rates be developed, it did prohibit tariff provisions inhibiting the pooling or development of market centers. This will give those advocating low backhaul rates an opportunity to argue that fully allocated backhaul rates violate that prohibition.

**[10]--Production-Area Rates.**

A similar set of arguments can be raised in the development of production-area rates. If rates in production areas are developed to create relatively high costs when compared to the distance of haul, pipeline-to-pipeline movement of gas in the production area will, so the argument goes, be frustrated. This will frustrate the development of multi-pipeline pools.
Conversions/Reductions.

The process of evolving from pre-restructuring to post-restructuring services will involve LDC elections of the services to purchase from pipelines. This can involve a decision whether to buy gas from the pipeline (and, if so, how much), and a decision with respect to which services (no-notice, firm transportation, storage) and in what quantities, the LDC wishes to purchase.

If the election must be made prior to the time the Commission finalizes the rates and tariff conditions applicable to service, there may be an inclination for LDCs to make overly cautious nominations. These may include a higher nomination for pipeline sales service based on the assumption that the pipeline will structure its tariff in a manner in which it, but not necessarily other competing merchants, feels comfortable doing business. It might also mean a greater than necessary nomination of no-notice service should proposed tight scheduling and imbalance tolerances survive FERC review.

Two other concerns have been raised with respect to the election process. First, is a fear expressed by non-pipeline suppliers that LDCs will nominate high pipeline sales to avoid transition costs by forcing pipelines to abrogate or renegotiate existing supply contracts. Similarly, pipeline "exit" fees for reductions of merchant service will be a cost factor in deciding to buy gas from others.\(^{160}\)

§ 15.05. Operations After Restructuring.

Once such issues as defining services and access to those services in the restructuring process are put to rest, the parties will have to turn their attention to performing the services as defined. In reality, however, the "how to" cousin to the "what are" of services will be also be determined in restructuring proceedings.

Capacity Allocation.

After capacity is apportioned generally in the definition and nominations stages of the restructuring process, attention will turn to day-to-day operational issues. How gas is actually nominated at given receipt and delivery points will have a significant impact on the usefulness of firm services. FERC has required pipelines to set forth in their tariff how capacity will be allocated at numerous points on their systems.\(^{161}\)

Receipt Point.

There are a couple of models for receipt point capacity allocations. Under the primary/secondary model, shippers can contract for "primary" receipt point rights. Generally, pipelines allow shippers to claim receipt point MDQs equal to delivery point MDQs. However, pipelines generally have significantly more receipt point capacity than delivery point capacity. Under a primary-point-only system, firm shippers would be denied access to a significant portion of the system, at least for the period required to amend their contracts to change primary points. In response to these concerns, some pipelines have allowed flexible or "secondary" receipt point access.\(^{162}\) While secondary access rights are subordinate to primary firm rights, they are superior to interruptible rights. Thus a firm shipper that looses its supply at a primary point can purchase supplies from a secondary point, or vice versa, and not be precluded from doing so because of preexisting interruptible transportation at the secondary point.

Another method of providing flexibility of receipt point access is the use of pools. "Pooling" is a method of aggregating supplies from many receipt points for a variety of markets. Just as the pipelines could aggregate supplies very simply for their merchant function, so too can other merchants under pooling systems.

A particularly useful pooling system to take advantage of receipt point flexibility is one that relies on
"feeder" agreements in production areas. Under feeder arrangements, aggregators nominate gas from numerous receipt points on their "feeder" agreement. The "feeder" brings gas to a pooling point, at which a shipper holding a contract for downstream transportation purchases some or all of the aggregator's gas and has it transferred to the shipper's agreement. In the event of a conflict at the pooling point, gas feeding from downstream agreements gets priority. Pooling points are established at points that are constrained historically, so that points upstream of the pooling point do not have to be allocated. Thus, the primary/secondary system may not be useful at receipt points on systems where feeders are appropriate.

Both feeder and primary/secondary constructs can work together. If there are a few periodically constrained receipt points and some mainline constraints, shippers who want certainty at the constrained points can use some of their rights to "reserve" those points via a "primary" designation. They may also reserve some of their capacity at the pooling points, leaving flexibility to buy from pools at all other points.

Once again, shippers must be cognizant of the impact of their choices on supply options and reliability. Aggregators must know the rights chosen by their marketers and be informed of any changes made by those marketers. Shippers may also choose to let their suppliers administer their firm capacity rights (e.g., to change primary points). Whether a pool can be a primary point may depend on whether it is a paper pool (using a fictitious point and no transportation) or a pooling point pool (involving feeder transportation and utilizing a physical point on the system). Those who rely on interruptible transportation must also be cognizant of the structure of firm rights, as the more flexible firm rights are, the less reliable interruptible service is likely to be.\(^{(163)}\)

[b]--Delivery Point.

In Order No. 636, the Commission affirmed its requirement to offer receipt point flexibility. It also required pipelines to offer the same flexibility at delivery points.\(^{(164)}\) It is entirely conceivable that the same theories for achieving flexibility at the receipt end of the pipeline will also work at the delivery end. Primary and secondary delivery points have been established on a limited number of pipelines.\(^{(165)}\) Delivery area pools might also be established.

[c]--Segment.

Some pipelines allocate capacity by pipeline segment. In essence, the pipeline segment is deemed the functional equivalent of a constrained point and, rather than using the point for demarcation, the entire segment is used.

Shippers should be aware of how capacity allocation will occur at each area of the pipeline system. They must be sure that they are not over- or under-counting capacity entitlements due to duplicative allocation areas.

[2]--Curtailments.

Order No. 636 requires participants in the restructuring process to develop plans for dealing with curtailments.\(^{(166)}\)

[a]--Transportation Capacity: Pro-rata Default.

Generally speaking, firm capacity curtailments are visited pro rata among the shippers. Whether the pro rata allocation is based on nominations, flowing gas, or contractual entitlements is tariff-based, but negotiable in tariff proceedings.
At least one pipeline has proposed in restructuring negotiations that firm capacity be curtailed based on the price being paid for it. If the pipeline had discounted firm capacity, the discounted capacity would be curtailed first. Traditionally, the Commission has taken a "firm is firm" approach to this issue. Nonetheless, with the Commission's emphasis of late on economic allocation of capacity, it is conceivable that the Commission will find a way to change its policy as it did with capacity brokering. Accordingly, shippers should no longer simply assume that "firm is firm."

The Commission has also allowed parties to agree to end-use based transportation curtailments. Cooperation among users will be a key to successful management of curtailments. One would expect that a tariff would include the means for parties to enter into voluntary arrangements to assure that high priority uses are protected when capacity problems arise. Unfortunately, with excess supplies and numerous other restructuring items on their plates, the parties to most restructuring proceedings are not spending a lot of time negotiating tools for voluntarily dealing with the possibility of capacity-related curtailments before they occur.

[b]--End-Use Curtailment.

When supply rather than capacity is short, the pipelines used to turn to their curtailment plans, which were based primarily on end-use. Under Order No. 636, these plans will only apply to pipeline sales-gas shortfalls. Shortfalls among other aggregators will be dealt with contractually. Aggregators serving differing markets would be well advised to include provisions in their contracts spelling out any priorities they may assign in the event of a supply shortfall. While the aggregator may be protected from liability when a force majeure event curtails all of its supply, it may not be protected when only part of the supply is curtailed and it has to decide which customer will get the remaining supplies.

[3]--Imbalances.

With pipelines shifting to transportation-only operations, keeping the overall system in balance will become increasingly the responsibility of individual shippers. In contrast, under a pipeline merchant system, the pipeline could adjust purchases or use storage when necessary to keep its system operating properly.

[a]--Historical Treatment.

Historically, the Commission allowed pipelines to penalize shippers for not balancing their injections and withdrawals from the system. These penalties could not be imposed without prior notice and an opportunity to cure. Daily tolerances tended to run about 10% and monthly tolerances 4%. Penalties tended to run at a level of twice the gas sales commodity rate for excess takes. For excess injections, pipelines were allowed to keep the gas. In addition, pipelines were allowed to impose "scheduling" penalties. These were calculated on variations from daily or monthly nominations, again after taking into account tolerances. For the most part, these penalties equaled the interruptible transportation rate in recognition of lost revenue for nominations made but not used.

Although few of these penalties were levied, debate over them raged in restructuring conferences. Issues such as whether a shipper should be penalized when it is out of balance one way (e.g., short) on one of its contracts and the other way (long) on another contract abounded. Similarly, if one shipper was long and another was short an equal amount, an argument could be made that the system did not suffer, and there should be no penalties. Conversely, those who could control their receipts and deliveries saw no reason to
allow others much leeway. Virtually everyone agreed that some incentive was needed for shippers to monitor their flows as best they could.

In the meantime, imbalances flourished on many pipelines. As penalties were not being applied with regularity, shippers were tempted to "pack" the line in the summer, when prices were low, and "draft" in the winter, when prices were higher. In addition, difficulty determining whose gas was whose when nominated amounts did not match actual flows at meters compounded the problem, as shippers who wanted to, and could, stay in balance could not determine their status. Making matters worse, retroactive reallocations of gas could change a shipper's imbalance status months or even years after the fact.

[b]-Developing Methodologies.

While it was generally agreed that the industry faces a growing imbalance problem, solutions are not easy to come by. It was really not until the early 1990's, more than four years after open-access operations began and problems mounted, that the industry reached a consensus on how to deal with the issue. The consensus represented agreement on a number of general principles, but the specifics of implementation were left to restructuring proceedings.

[i]-Operational Balancing Agreements

(OBA)/Pools.

The first general principle was the necessity of developing a means of netting imbalances across contracts held or served by an individual shipper or supplier. Operational balancing agreements (OBAs) were developed to allow numerous producers delivering gas to the pipeline at a common receipt point or common set of receipt points to agree among themselves whose gas had flowed on any given day and to provide that information to the pipeline. Often, an OBA is used to "move" the legal incidence for any penalty from a shipper with a transportation agreement to the OBA-holder.

Similarly, aggregator pools could serve the same purpose for those aggregating from many points to many markets, but without direct control over the receipt point facilities where gas was injected. So long as an aggregator pool is in balance, there is no need to penalize the aggregator, or a shipper purchasing from the aggregator, simply because certain points were out of balance (or so the theory goes).

These concepts were originally developed with receipt points in mind, but their value has been recognized also for delivery points. LDCs with multiple delivery points argue that they should be able to aggregate deliveries for imbalance purposes just as any supplier can aggregate receipts. Given FERC's mandate for consistent receipt and delivery point flexibility, these arguments likely will prevail ultimately.

A more difficult area involves pipeline interconnections. While a given pipeline may be forced to, or may voluntarily, agree with its customers as to imbalances on its own system during the course of restructuring negotiations, there is no ready forum for dealing with pipeline-to-pipeline gas transfers for multiple shippers. Some pipelines are volunteering to enter into OBAs with other pipelines, others simply refuse. Thus, to the extent a supplier relies on upstream pipeline facilities to deliver gas to a system without an OBA in place, it may see the benefits of these mechanisms partially negated.

[ii]-Predetermined Allocation: "Through the Meter" Order.
Retroactive reallocations are causing significant uncertainty. To avoid this, pipelines began pushing the concept of "predetermined" allocations. In essence, a predetermined allocation provides, for example, that if 100 units are scheduled to show up at a receipt point for three different shippers and only 90 arrive, the shipper or shippers who will get "shorted" (and by what percentage of the overall "short") are determined in advance, with little or no opportunity for retroactive reallocation.

Predetermined allocations appear to be on the verge of becoming a standard allocation method. Shippers must be aware of their place on their supplier's allocation list so that, when they commit to make supply available or expect supply to show up, they do not see their expectations frustrated by a predetermined allocation agreement.\(^{(185)}\)

[iii]--Bookouts.

"Bookouts" is a term gaining popularity for describing a process by which a pipeline allows shippers to net their imbalances on various agreements against their own and other shippers' imbalances.\(^{(186)}\) In essence, a shipper would be allowed to tell the pipeline to net imbalances on all its various contracts before imposing penalties, with the netting a matter of cross-contract accounting entries.\(^{(187)}\) Trading imbalances among shippers is also likely to take hold as a means resolving imbalances. The level of utilization of bookouts on a given system will likely depend on the pipeline's pooling rules, as pooling serves the same purpose, and may involve pool-to-pool bookouts between aggregators.

[iv]--Cashouts.

"Cashouts"--paying a market price to resolve imbalances--is a direct reaction to the arbitrage temptation. If a shipper puts more gas on the system in a month than it takes off when the price is $1.50, it cannot take its gas off in another month when the price is $2.00. On a pipeline using cashout procedures, the pipeline would pay $1.50 in the first month for excess deliveries onto its system and would receive $2.00 for excess deliveries out of its system in the later month. To keep shippers from using the pipeline as a dumping ground for excess gas or as a source of supply, tolerances are established at various levels, and penalties--generally a percentage deduction from or addition to market price--are applied when tolerances are exceeded.

While the cashout is gaining in popularity, many seemingly minor issues having large dollar consequences remain. For instance, the appropriate index for a monthly cashout price is difficult to determine because end-of-month prices are more reflective of the next, than the current, month. Those subject to cashouts should also determine whether penalties apply just to the volumes over the threshold, or whether a certain penalty level will apply to all imbalance volumes.

Despite its increasing popularity, cashout is not accepted by all shippers, particularly not by those who think that they can buy below or sell above cashout indices. There is a strong contingent in favor of allowing "in kind" resolution of imbalances and, most recently, trading of imbalances. Suppliers and purchasers should be aware of all options when attempting to resolve imbalances.

[4]--Supply Aggregation.

How aggregators will duplicate the firm sales function, formerly the exclusive domain of pipelines, will depend on the tools provided by the pipelines whose delivery services they will use. Pooling is the method of choice for many aggregators. Under the pooling point option, aggregators will use their own agreements to ship gas to the pooling points, while downstream "take-away" capacity will likely belong to the LDC markets. Aggregators will perform receipt point nominations functions on their own and turn control of gas over to the marketer. Marketers that desire city gate service, or perhaps do not want to perform gas
scheduling and dispatching functions themselves, may delegate authority to operate their service agreements to aggregators.

Potential obstacles loom with respect to any of these aggregation methods, obstacles that could determine the shape of markets in the future. For instance, administrative fees applied to paper or point pooling or rates for poolers that are greater than those applicable for wellhead-to-city gate service could deter use of these tools in favor of historical point-to-point nominations. Similarly, if the use of pools results in a lesser priority for pooled supplies through capacity constraints, point-to-point service is likely to prevail. In addition, the location of pooling points could have an impact on the economics of certain supplies.\(^\text{(188)}\)

At the extreme, if pooling is severely restricted and tariff conditions on delegating rights to administer service agreements prevent rights from being delegated monthly,\(^\text{(189)}\) the marketer using firm transportation will be relegated to long-term contracts. This will restrict LDCs from developing their desired portfolio approach to purchases.\(^\text{(190)}\) If pools are required to be segregated into those serving firm and those serving interruptible markets,\(^\text{(191)}\) flexibility to move gas from market to market will be sacrificed.

Limits on OBA\s can also affect marketers. For instance, if only facility owners can enter into OBA\s, marketers could be placed at a disadvantage to producers marketing their own supplies where there is no other means to offset imbalances to mitigate imbalance and scheduling penalties. Even where OBA\s are available to aggregators, limits on their availability, including creditworthiness and required levels of contractual control over receipt point flows, could make them less useful as aggregation tools than they otherwise could be. Each of these restrictions will favor sales from large receipt points, such as processing plants, over the use of multiple points flowing lesser volumes. This could have a negative impact on independent producers and reliability from diversity.

[5]--Swing Supply Management.

Ultimately, the effectiveness of the post-restructing gas market will depend, not on any one aggregation tool, but on a combination of many small tools. From a delivery perspective, no-notice services will be available to help assure that capacity will be available to deal with unanticipated swings. However, no-notice capacity might not be sufficient if supplies are not readily available.

In the market area, LDC\s can enter into mutual assistance agreements with each other. Industrial users with fuel switching capability can enter into agreements to release their supplies when needed by those without switching capabilities. LDC, pipeline, and third-party market-area storage will also help to mitigate the impacts of supply shortages.

In the supply areas, swing providers can agree to deliver supplies on demand. Production area storage can also come into play.

Line pack--gas in the pipeline from time to time--can also be drawn on in a supply emergency. The Commission has authorized pipelines to require parties to pack the line in anticipation of weather fronts\(^\text{(192)}\) to maximize deliverability on peak days or otherwise to maintain line pressure. Whether parties may pack lines voluntarily will be decided in restructuring proceedings.

Each of these tools will involve advance contractual arrangements. Swing providers and takers will have the opportunity, not only to help the rest of the system, but also to profit from their abilities and, perhaps, to offset higher firm demand charges occasioned by the use of SFV rates.

§ 15.06. Capacity Reassignment/Relinquishment.
Another way of mitigating the impact of SFV rate design is through the release of capacity. Again, however, the rules applicable to releases will have a significant impact on price and availability of released capacity.

The Commission envisions that released capacity will be put out to bid on the pipelines' electronic bulletin boards. (193) Lead times, credit checks, bid windows, penalties for failure to perform, and possible preferences for various types of bidders are but few of the subjects to be addressed in restructuring proceedings. How a best bid is determined (e.g., strictly on price, on price and term, or on such other factors as promised load factor of usage), by whom (pipeline or LDC), and with what public disclosure have all been hotly debated early in the restructuring process.

The Commission also envisions that pipelines will charge an administrative fee for capacity releases and may charge a negotiated incentive fee for helping to market released capacity. The structure of these fees could impact the viability of the released capacity market (194) and encourage the development of alternative "match-makers."

§ 15.07. Transition Costs.

The Commission has authorized full recovery of four categories of Transition Costs. While one hopes that the recovery of these costs will be accomplished quickly, recovery methods could affect supplier-market relationships during the recovery period.

[1]--858 Capacity.

Costs associated with third-party service contracts with pipelines can be recovered through assignment of those contracts, through retention of the capacity and payment of demand charges as Transition Costs, or by other means. Less than full recovery is possible if the contract is found not to be used and useful. (195)

The choice of recovery method could impact the availability of upstream capacity to non-pipeline suppliers in a number of ways. For instance, a pipeline may claim the right to recall assigned capacity if it is needed to transport previously contracted supplies. Alternatively, a pipeline may be willing to grant use priority to those willing to take an assignment of contracted supplies. Rules governing the uses of non-assigned yet retained upstream capacity rights could impact reliability. In short, before relying on upstream capacity secured through the downstream pipeline, parties who would use that capacity should carefully research the applicable rules.

[2]--Facilities.

The installation of additional telemetry, interconnects, and other facilities related to the Order No. 636 transition will result in additional costs for the pipeline. These costs will find their way into rates via limited Section 4 rate filings, (196) which will allow for rate increases without immediate corresponding decreases associated with reduction of the pipeline's rate base from depreciation. Those executing firm agreements should plan for rate increases or negotiate rate caps. Telemetry, on the other hand, will provide the potential for more efficient supply management and the avoidance or mitigation of penalties.

[3]--Purchased Gas Adjustment.

Direct-billing of remaining deferred costs of previously purchased gas should have an impact on future supply relationships only if it is linked to some other aspect of a pipeline's restructuring. (197) Otherwise, the direct billing of PGA balances should spell the formal end for retroactive gas cost surcharges. (198)

[4]--Supply Realignment.
Existing contracts between pipelines and producers will play an important role in the restructuring process. These contracts may be offered for assignment, giving rise to a host of contractual issues as to their eligibility for assignment. It may even be suggested that the assignment be subsidized.\(^{(199)}\)

Contracts retained by the pipeline may be "bought down" in price rather than terminated. This will give rise to questions as to the appropriate price to which the contracts will be bought down. If bought down, through the collection of Transition Costs levied on transportation in general, to a price below what it would take to purchase alternative supplies, the pipeline merchant function could end up being subsidized by its competitors. Issues will also arise as to the disposition of below-market contracts in the pipeline's portfolio.\(^{(200)}\)

Billions of dollars in contract reformation costs are being claimed in the restructuring process. Nonetheless, some participants would have it shrouded in secrecy, beyond a veil of confidential treatment.\(^{(201)}\) There is bound to be protracted debate over the recovery of these costs. An interesting proposal, taking a quite different tack, would have the pipeline auction off its supply contracts, so that it will pay the lowest bidder to take non-market responsive contracts off its hands. If there is sufficient interest in the contracts and the bidding process is otherwise fair, this could provide a viable means for establishing supply realignment costs, and, perhaps, avoiding litigation over the contract's prudence.\(^{(202)}\) Other alternatives include measuring buy-down prices against futures prices or available "commodity swaps," as well as requiring pipelines to offer contracts for assignment after they have been bought down.

[5]--Recovery Mechanism.

There are a number of potential methods for recovering transition costs. All but direct bills to existing sales customers could impact future supply choices of existing customers. Once again, those entering into firm service agreements should be aware of the possibility of future surcharges.\(^{(203)}\)

§ 15.08. Market Centers.

One of the least defined and, perhaps, most important theories propounded in Order No. 636--in fact, written into the regulations--is the market center concept. FERC falls short of mandating the creation of market centers, relying on the market itself to create them without roadblocks from tariff restrictions.

The market center concept began before Order No. 636. In 1989-90, the New York Mercantile Exchange (NYMEX) established a contract for futures trading at the Henry Hub in Louisiana. The Commission's market center encouragements could result in trading at numerous hubs. In turn, new and creative ways of pricing contracts, reducing risk, and otherwise trading gas will come to the fore in the future. Use of these methods will require that contracts be drafted to recognize the requirements of futures trading.

§ 15.09. After All Is Said and Done, Will It Hold Up to Judicial Review?

This discussion has been premised on Order No. 636 being implemented without significant change or judicial upset. With over 200 parties filing comments at one time or another in the rulemaking process, and hundreds of parties in each restructuring proceeding, perhaps the most certain thing that can be predicted is that Order No. 636 will find its way into court.

Likely candidates for attack include the Commission's finding that bundled merchant service operates "in a manner that causes considerable competitive harm to all segments of the natural gas industry[,]" and thus amounts to an "unlawful restraint of trade."\(^{(204)}\) The implementation process itself, relying on "compliance
With such a massive breadth and reach, it is almost unthinkable that the entirety of Order No. 636 will be upheld on review. Thus, those entering into contracts on a long-term basis should look closely at their force majeure clauses, particularly at "regulatory out" provisions, to assure that they are aware of the consequences of changes in the regulations, either by FERC or as a result of court action.

§ 15.10. Conclusion.

Despite the length of this Chapter, we have really just scratched the surface when thinking about what Order No. 636 will ultimately mean in terms of restructured relationships in the gas industry. One can expect that the Order will result in more creatively drafted and more carefully tailored gas supply contracts for LDCs. Many old concepts will be given new names and recycled for use in freely negotiated supply arrangements. New tools, perhaps relying on futures markets, will proliferate.

Throughout this Chapter, we have advised those entering into supply arrangements to take into account tariff provisions emanating from restructuring proceedings when drafting their agreements. While the Commission is relying more on negotiated contracts than on regulation to define the rules applicable to gas sales, we would be remiss not to offer a final word of caution. The vast majority of gas sales will rely on transportation across an interstate pipeline. Until the NGA is amended, pipelines can change their tariff provisions virtually at will, by making a Section 4 tariff filing. While the Commission can suspend the date that filing can become effective, unless unjust and unreasonable on its face, the change could go into effect subject to an ineffectual "refund" obligation, creating substantial competitive or economic dislocation to shippers.

In sum, Order No. 636 creates tremendous opportunities for creative supply acquisition and sales. It does not, however, totally deregulate the gas industry. Whether this should ultimately occur will be subject to debate for some time to come. For now, the industry will focus on the new age at its doorstep.

§ 15.11. Addendum on Order 636-A.

On August 3, 1992, the Federal Energy Regulatory Commission issued Order No. 636-A. The order largely denied rehearing of Order No. 636, but made several meaningful changes. In addition, the Commission clarified several of its statements in Order No. 636.

[1]--Capacity Assignment.

The Commission generally denied rehearing on the new on-system capacity assignment and release rules. However, it did make several changes to the capacity assignment mechanisms to foster short-term releases. Under the revised rules, shippers may release capacity for any period of less than one month without prior posting on the pipeline's electronic bulletin board (EBB) or bidding for the released capacity. These releases must be announced on the EBB as soon as possible after the transaction commences, but no later than forty eight hours following commencement. No rollovers or extensions will be permitted without prior notice or the opportunity to bid for the capacity. The same maximum rate would apply as to other capacity release transactions.

The rehearing order clarifies the best bid requirements. Pipeline tariffs must include an "objective and nondiscriminatory economic standard for determining best bids." However, the standard is not binding;
releasing shippers may specify their own "reasonable and non-discriminatory terms and conditions." Releasing shippers that do not specify terms and conditions default to the standards in the pipeline's tariff.

A releasing shipper paying *discounted* rates is entitled to receive the proceeds from a release even if such proceeds *exceed* its reservation fee (212) and will be ultimately responsible for only underlying reservation charges, as opposed to all charges related to the use of released capacity (e.g., volumetric charges and penalties). (213) The Commission revised its position on pipeline collection of an "administrative fee" for operating the release mechanism, so that the pipelines can not recover the costs of operating the program through a separately stated fee. (214)

With respect to *upstream capacity*, the Commission clarified that "upstream pipelines" may retain production area capacity rights "upstream of the place of unbundling, but only to the extent the pipelines need those rights . . . to make their unbundled sales at their place of unbundling." (215) Downstream pipelines may retain upstream pipeline capacity downstream of the point of unbundling, but only to the extent necessary for operational management and balancing purposes. (216) Allocation of capacity between the pipeline and other shippers must be accomplished on a non-discriminatory basis. (217) Thus, pipeline preferences for anything but operational flexibility appear to be prohibited.

### [2]--Electronic Bulletin Boards.

The Commission made several changes to the Electronic Bulletin Boards (EBB) requirements. (218) In order to allow releases to be consummated without pipeline participation, pipelines must provide "interactive" EBBs "if feasible on the particular system," or must explain why an interactive EBB is not appropriate. (219) Addressing competition between interruptible transportation and released capacity, the Commission clarified that the pipeline should recover the *fixed* costs associated with the EBB in its cost of service, but could charge a fee to recover the variable costs.

### [3]--No-Notice Service.

The Commission provided a number of clarifications regarding no-notice service. Pipelines are not required to provide back-up supplies, but added that pipelines are responsible for "normal balancing associated with system integrity and efficiency." (220) Pipelines are required to "offer 100 percent no-notice service on all days of the year." (221) Pipelines are required to offer no-notice transportation service only to customers that were entitled to receive a no-notice firm, city-gate sales service on May 18, 1992. (222) The Commission also suggested that no-notice service can be a bundled transportation and storage service. (223)

### [4]--Storage.

The Commission clarified that current bundled firm-sales customers have a priority right to the storage necessary to maintain their level of maximum daily entitlements, regardless of whether they elect no-notice service. (224) The Commission did not directly address the issue of whether pipelines are required to make specific capacity in specific fields available, referring the issue to the restructuring proceedings. The Commission clarified the ability of existing storage customers to retain their existing rights *but* the terms and conditions associated with their rights may be changed if "they proved unreasonable in light of Order No. 636's requirements of no-notice transportation and open access contract storage." (225)

### [5]--Rate Design--Small Customers.

The Commission required pipelines that, on May 18, 1992, offered a small customer sales or transportation
service on a one-part volumetric basis at an imputed load factor, offer all firm transportation service, including no-notice transportation, on the same basis--including the same eligibility criteria--to small customers. "Small customers" are as defined in the respective pipelines' tariffs. Pipelines must "consider" enlarging the size of the small customer class up to 10,000 Mcf or Dth/day.

[6]--Pipeline Sales--Small Customers.

For one year from the effective date of the pipelines' blanket sales certificate, pipelines must sell gas to "current" small customers at a cost-based rate--based upon their actual price paid for gas--if the small customers elect that service. The interim measure allows these customers time to enter into alternative supply arrangements.

[7]--Pipeline Service Obligation (After Restructuring).

The Commission modified the right of first refusal rules to require a long-term firm transportation customer to match the price of a competing bidder up to the maximum just and reasonable rate; the longest contract term the customer must match is twenty years. Previously, there was no limit on the term to be matched. The Commission clarified that the right of first refusal can be exercised by the original shipper for whatever term it chooses and for any quantity up to the shipper's original quantity. "Long term" is re-defined to "one year or more." Previously, the definition was "more than one year."

[8]--Transition Costs--Gas Supply Realignment Costs.

On rehearing, the Commission determined that pipelines must recover 10% of their prudently incurred gas supply realignment (GSR) costs from their Part 284 interruptible transportation service. Previously, 100% of these costs were to be recovered through a reservation surcharge or exit fee on firm customers.

From a perspective of current sellers to pipelines, the Commission made a somewhat provocative statement: "If pipelines have rights under their producer supply contracts [i.e., FERC-out or market-out provisions] to adjust the price or terms of those contracts, of course they should exercise those rights for the benefit of their customers. A failure to do so would clearly be imprudent."

1. * The author wishes to acknowledge the contributions to this Chapter of Charles S. Schultz and Gordon Smith, associates with the John, Hengerer & Esposito firm.


3. 2. For example, a producer could sell gas to a processor, who, in turn sold it to a pipeline; or, a partial (e.g., non-working) interest owner producer could sell gas through the operator.

4. 3. Until 1978, the pipeline would ordinarily be "intrastate" if the gas was to be consumed in the state of production and "interstate" if consumption was outside the state of production.

5. 4. In Panhandle Eastern Pipe Line Co. v. Public Serv. Comm'n, 332 U.S. 507, 516 (1947), the Supreme Court held that the NGA was applicable to (1) transportation of natural gas in interstate commerce, (2) sale in interstate commerce for resale, and (3) natural gas companies engaged in interstate transportation or sale. Therefore, "[b]efore a pipeline may acquire or construct any facilities or offer any transportation or sales service subject to the Commission's NGA jurisdiction, it must obtain a § 7 [of the NGA] certificate authorizing the acts." Associated Gas Distrib. v. FERC, 824 F.2d 981, 1030 (D.C. Cir. 1987). In Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954), the Supreme Court held for the first time that NGA sale for resale jurisdiction applied to wellhead sales by producers to interstate pipelines, as well as to any other sale in interstate commerce for resale. However, direct sales by interstate pipelines to industrial customers were determined to be within the states' jurisdiction. Panhandle Eastern Pipe Line Co. v. Public Serv. Comm'n of Indiana, 322 U.S. 507 (1947). LDC sales to consumers are generally regulated by state agencies.


8. 2. See Consolidated Edison Co. of N.Y., Inc. v. FERC, 823 F.2d 630, 633 (D.C. Cir. 1987).


17. 11. Order No. 234-B, "Interstate Pipeline Certificates for Routine Transactions," FERC Stats. & Regs. [Regulations Preambles 1982-1985] ¶ 30,368 (1982). In Order No. 234-B, the Commission amended its regulations to provide for issuing "blanket" certificates under which interstate pipelines were authorized to undertake certain activities subject to particular conditions. Specifically, the activities covered by the final rule included: (1) construction, acquisition, operation, and miscellaneous rearrangement of facilities; (2) construction and operation of sales taps; (3) changes in delivery points; (4) storage services; (5) an increase in storage capacity; (6) underground storage testing and development; (7) abandonment; (8) changes in rate schedule; and (9) changes in a customer's name.


21. 15. In Wisconsin Gas Company v. FERC, 770 F.2d 1144 (D.C. Cir. 1985), the court upheld Order No. 380, finding: (1) Minimum bills allow pipelines to recover for variable costs that they do not incur; (2) minimum bills prevent gas purchasers from purchasing the lowest priced gas and, hence, artificially maintain high gas prices; and (3) the benefit of eliminating variable cost recovery through minimum bills outweighs the negative impact such action will have upon pipelines and upon full requirements customers.


23. 17. See Maryland People's Counsel v. FERC (MPC I), 761 F.2d 768 (D.C. Cir. 1985).

24. 18. Id. at 771.

26. 20. MPC I, 761 F.2d at 779.


29. 23. Order No. 436 at 31,494.

30. 24. The court noted that Order No. 436 will lead pipelines to "transport the gas with which their own sales compete; competition from other gas sellers will give consumers the benefit of a competitive wellhead market." AGD I, 824 F.2d at 994.


33. 27. AGD I, 824 F.2d 981 (D.C. Cir. 1987).


35. 29. Under Order No. 500, the Commission also required that producers to submit a signed offer of take-or-pay credits to any open-access pipeline to make the producer's gas eligible for transportation, unless the pipeline had agreed to transport the gas without an offer of credits. "Order Explaining Crediting Provisions of Order No. 500," 41 FERC ¶ 61,025 (October 16, 1987).

36. 30. The Commission also suggested that pipelines be able to pass through, on an "as-billed basis," producer demand charges. An early attempt by one pipeline to do so, however, was rebuffed by the Commission. Tennessee Gas Pipeline Company, 42 FERC ¶ 61,368 (1988).

37. 31. Order No. 500 at 30,787. The amounts to be recovered through fixed charges were allocated on the basis of each customer's "purchase deficiency," calculated by measuring the customer's purchases in the "deficiency period" against the customer's purchases in a prior "base period."


40. 34. These included: (1) spreading costs as broadly as possible, (2) absorption by pipelines of a significant portion of the costs, (3) minimization of burdens on captive sales customers, especially small customers, and (4) recognition of existing pipeline-producer settlement agreements.


38. 2. In the Preamble to Order No. 636, the Commission makes an explicit finding that bundled sales service violates § 5 of the NGA (15 U.S.C. § 717d):

Based upon the extensive record developed in this entire proceeding, as well as the Commission's observations of the industry, the Commission finds that the pipelines' bundled, city-gate, firm sales service is operating, and will continue to operate, in a manner that causes considerable competitive harm to all segments of the natural gas industry as described above. The Commission finds that this harm has an unreasonable impact on gas sellers and gas purchasers and is an unlawful restraint of trade which is not balanced by the "no-notice" aspect of the bundled, city-gate sales service because, as fully discussed below, the pipelines can and will be able to provide a "no-notice" transportation service for all gas supplies without the competitive harm attendant to the current bundled, city-gate, firm sales service. Restricting access to a "no-notice" service by limiting its availability to the purchase of pipeline sales gas is anticompetitive. The bundled, city-gate, firm sales service provides the pipelines with an undue advantage and subjects other gas merchants to an undue disadvantage. It maintains an unreasonable difference in service between classes of service (bundled, city-gate, firm sales and open access firm transportation) because the firm transportation embedded within the firm sales is superior in quality as discussed above. The Commission, therefore, finds and concludes that the pipelines' bundled, city-gate, firm sales service violates NGA sections 4(b) and 5(a).

Order No. 636 at 30,405 (footnote omitted).


41. 5. The "maximum daily quantity" of gas a pipeline is required to provide under a sales contract is commonly referred to as the "MDQ." The same concept--maximum contract obligation or entitlement--is also commonly expressed as contract demand (CD), among other terms.

42. 6. In other words, if the bundled sales service was provided solely with firm transportation and sales gas, two contracts would emerge from the unbundling process--one for firm transportation (at the pre-existing CD, less reassigned CD, if any) and a second for sales service (which could unilaterally be reduced).

43. 7. Order No. 636 at 30,410.

44. 8. \textit{Id}.

45. 9. \textit{Id} at 30,414.

46. 10. This takes on particular significance when compared to the language of §§ 4 and 5 the NGA, which prohibit \textit{undue} preference or discrimination. 15 U.S.C. §§ 717c and 717d.

47. 11. Specifically, Order No. 636 at 30,414 sets forth the following equality requirement:

The Commission is amending Part 284 to require an open-access pipeline that offers firm and interruptible transportation services to provide those transportation services on a basis that is equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere.

48. 12. There are solid legal arguments to prohibit the Commission from exercising this authority in any event. NGA § 1, 15 U.S.C. § 717, granted the Federal Power Commission (predecessor of FERC) jurisdiction to regulate (1) sales for resale in interstate
commerce, (2) transportation in interstate commerce, and (3) facilities used for interstate sales and transportation. Significantly, the NGA did not obligate pipelines to provide third parties access to their facilities.

55. 13. Order No. 436 at 31,516. It should be noted that the Commission, for some time, has been leaning toward allocation of capacity based on the price bid. For example, interruptible service at a discounted rate may be curtailed in favor of a later customer who is willing to pay a higher rate. See Northern Natural Gas Co., 37 FERC ¶ 61,272, 61,819 (1986); Transcontinental Gas Pipe Line Corp., 38 FERC ¶ 61,165, 61,504 (1987); Natural Gas Pipeline Co. of Amer., 39 FERC ¶ 61,153, 61,595 (1987).

56. 14. These standards include:

(1) Pipelines must not provide preferential access to any users of the electronic bulletin board.

(2) Pipelines must permit users to download files from the board, so their contents can be reviewed in detail without tying up access to the board.

(3) Pipelines must keep daily back-up records of the information displayed on their bulletin boards for at least three years and permit users to review those records, which should be archived and reasonably accessible.

(4) Pipelines must periodically purge transactions from current files when transactions have been completed, so that users do not have to sift through massive amounts of historical data to find current information.

(5) Electronic bulletin boards must be "user-friendly."

(6) Pipelines were also recommended to utilize software with on-line help, a search function that permits users to locate all information concerning a specific transaction, and menus that permit users to access separately each record in the transportation log, notices of available capacity, and standards of conduct information.

Order No. 636 at 30,415.

57. 15. The specificity with which a pipeline sets out its operating procedures will be the subject of debate in the restructuring process. As a preview, see the Initial and Reply Briefs of the Indicated Shippers in Columbia Gas Transmission Corporation, FERC Docket No. RP90-108-000, where the issue raised is whether pooling procedures should be specifically stated in the pipeline's tariff.


59. 17. "Within path" refers to the contracted for points of receipt and delivery. With respect to a contract for transportation from Texas to New Jersey, a point in Connecticut would normally not be "within path."

60. 18. Order No. 636 at 30,402.

61. 19. 18 C.F.R. § 284.1.


63. 21. Id. at 30,427.

64. 22. Id. at 30,417.

65. 23. Id. at 30,417. By "permanent," the Commission means for the life of the underlying contract. Nonetheless, in another section of the Order, the Commission provides a mechanism to protect assignees from losing service at the termination of the underlying contract.

66. 24. Id. at 30,418.

67. 25. Traditionally, these "end-use" customers could only obtain access to interruptible transportation service, even though many--particularly large industrial users--may have been willing to pay for firm service. In turn, LDCs retained an obligation to provide gas to these end-use customers on a peak day, even if the customer purchased most of its supplies on the spot market. In a sense, this is a
mirror image of the pipeline/LDC relationship at a local level. Unlike many pipelines, however, many LDCs had preexisting agreements with their large industrial customers where the large industrials would turn to alternative fuels on peak days, thereby alleviating a portion of the LDC's peak obligations.


69. 27. Id.

70. 28. Id.

71. 29. Id. at 30,419.

72. 30. Id. at 30,420-21.


75. 33. On January 22, 1992, representatives from all segments of the natural gas industry discussed issues with respect to the operational aspects of the RM91-11-000 Notice of Proposed Rulemaking with the Commission at a technical conference.

76. 34. Order No. 636 at 30,410.

77. 35. Specifically, the Commission stated that it will:

not impose or forbid any particular operational conditions at this time. The pipelines and interested participants need the flexibility to explore all aspects of how the pipelines can provide this service in light of the individual configurations of the pipeline systems. Of course, the operational conditions must be devised and implemented on a nondiscriminatory basis for all shippers. Simply put, the Commission will not allow any operationally related tariff provision to undermine the quality of unbundled services the pipeline will be required to provide or to give a competitive advantage to the pipeline as a seller or to its marketing affiliate.

Id. at 30,422.

78. 36. See Natural Gas Pipeline Co. of Amer., Opinion No. 256, 37 FERC ¶ 61,215 (1986). Under the SFV methodology, all fixed costs are recovered in a demand charge, payable without regard to whether any service is actually performed. This makes the incremental cost of gas cheap relative to that moving under other rate methodologies. Under the other methodologies, a portion of pipeline fixed costs are allocated to, and recovered as, part of commodity (or usage) charges. As a result, purchasers who have already paid demand charges and are using least-cost purchasing strategies are more inclined to purchase gas transported under an SFV rate design, other things being equal.


80. 38. Id.


82. 40. Id. at 30,436. The Commission stated:

Potential phase-in methods could include use of a one-part volumetric rate or seasonal contract entitlement levels for small customers, creation of new customer classes based on load factor ranges, or creation of new customer classes on that or another basis in order to continue the use of MFV for cost allocation and SFV for billing.

83. 41. Id. at 30,437-38.
84. As an incentive for pipelines to come into compliance with Order No. 636, price-deregulated sales cannot occur until tariff sheets implementing the restructuring have been accepted as in full compliance with the Order and made effective. *Id.* at 30,438.

85. See also *Arkla Energy Resources, Inc.*, 59 FERC ¶ 61,173 (1992), where the Commission invalidated existing ISS certificates and dismissed outstanding ISS applications.

86. See also *Arkla Energy Resources, Inc.*, 59 FERC ¶ 61,173 (1992), where the Commission invalidated existing ISS certificates and dismissed outstanding ISS applications.

87. Those with gas purchase and sales contracts whose prices are tied to PGA pricing will have to turn to alternative pricing provisions.

88. See also *Arkla Energy Resources, Inc.*, 59 FERC ¶ 61,173 (1992), where the Commission invalidated existing ISS certificates and dismissed outstanding ISS applications.

89. Because determining gas costs and revenues is not an exact science, many pipelines have PGA accounts that carry substantial deferred gas costs.

90. An exit fees could be a charge based on reductions in sales levels or reductions in firm capacity entitlements.

91. There is an element of equity here. If the pipeline reduces an LDC's throughput and sales by connecting directly with an end-user that would otherwise have been served by the LDC, the LDC rightfully might be relieved of demand charges on the pipeline to the extent that the bypass has reduced the LDC's ability to shoulder the demand charge. Conversely, it may be difficult to show what portion, if any, of the LDC's reservation of firm capacity was attributable to the particular end-user. Since the issuance of Order No. 436, the Commission has refused to consider LDC arguments regarding the impacts of bypasses caused by the shifting of costs. See *Northern Natural Gas Co.*, 48 FERC ¶ 61,232 (1989); *Panhandle Eastern Pipeline Co.*, 48 FERC ¶ 61,233 (1989); *Cascade Natural Gas Co. v. Northwest Pipeline Corp.*, 48 FERC ¶ 61,234 (1989).


95. See 18 C.F.R. Pts. 161 and 250.
55. Order No. 636 at 30,442.

98. 56. Id. at 30,402-03, nn. 67 and 68.


100. 58. Section 284.221(d) of the Commission's Regulations, 18 C.F.R. § 284.221(d), states that "pursuant to section 7(b) of the Natural Gas Act abandonment of transportation services is authorized upon the expiration of the contractual term of each individual transportation arrangement authorized under a certificate granted under this section."

101. 59. Order No. 636 amends Section 284.221 to state:

(2) Paragraph (d)(1) of this section does not apply if the individual transportation arrangement is for firm transportation under a contract with a term of more than one year, and the firm shipper:

(i) Exercises any contractual right to continue such service; or

(ii) Gives notice that it wants to continue its transportation arrangement and will match the longest term and highest rate for its firm service, up to the maximum rate under § 284.7, offered to the pipeline during the period established in the pipeline's tariff for receiving such offers by any other person desiring firm capacity, and executes a contract matching those terms.

102. 60. Order No. 636 at 30,449.

103. 1. Presently, flexibility associated with diversity is generally limited to the pipeline on which aggregation occurs, i.e., on the pipeline that serves the LDC.

104. 2. In particular, FERC noted that it would be prepared to address arguments that individual pipelines still had market power over gas sales despite restructuring. Order No. 636 at 30,439.

105. 3. Order No. 636 at 30,443.

106. 4. Id.

107. 5. Order No. 636 at 30,393. New § 284.283, 15 C.F.R. § 284.283 of the Commission's regulations defines the point of unbundling as: "A sales service is unbundled when gas is sold at a point before it enters a mainline system, at an entry point to a mainline system from a production area, or at an intersection with another pipeline system."

108. 6. Id. at 30,410.

109. 7. This creates an interesting issue with regard to the competitive consequences of the unbundling rule. By requiring pipelines to "unbundle" at upstream points, FERC arguably preclude city-gate pricing for pipeline merchants. Nonetheless, the pipeline merchant is specifically authorized to repackage services so as to provide city-gate deliveries using its customers' capacity. Ultimately, the resolution of this potential disadvantage could turn on LDCs' willingness to release capacity in favor of the pipeline, so that the pipeline can be a holder of capacity in its own right. If the LDCs refuse to relinquish capacity, the point of sale would be the point at which the gas begins to be transported under the LDCs' agreements. While the point at which custody is transferred may differ, the perceived disadvantage may never materialize unless the pipelines are precluded from holding capacity in their own right when others are, as a legal and practical matter, allowed to do so.

110. 8. This allows the pipeline to buy gas for which the costs of transporting to the mainline are recovered in rates paid by those purchasing gas from competitors.

111. 9. 18 C.F.R. § 284.8(b) and § 284.9(b) provide that firm and interruptible transportation service must be provided on a non-discriminatory basis. 18 C.F.R. § 161.3(i) provides that, if a pipeline offers a transportation discount to an affiliate, it must make a comparable discount available to all similarly situated non-affiliated shippers.

112. 10. See Northern Natural Gas Co., 42 FERC ¶ 61,303 (1988); Transwestern Pipeline Co., 43 FERC ¶ 61,240 (1988); El Paso

114. 12. After all, the revenue stream to the pipeline would be the same, assuming it made the sales, no matter where the discount was taken. Some pipelines went so far as to propose tariffs that required the discount to come from somewhere other than transportation. E.g., Northwest Pipeline Corp.’s application filed March 13, 1990, in FERC Docket No. CP90-869-000.


116. 14. Order No. 636 at 30,442. Finding that the pipeline as a merchant is the functional equivalent of a marketing affiliate, the Commission concluded that Order No. 497’s standards of conduct should apply to the pipeline when it provides unbundled gas sales services.

117. 15. For example, to what extent must the merchant and transportation functions be separated? Can the same executive vice-president run both divisions? How will overhead for shared services be allocated?

118. 16. The marketing affiliate has not been subjected to many of the rules to which a pipeline merchant would be subject and is essentially beyond the Commission’s certificate authority.

119. 17. This can occur because of the need for redundancy in the receipt area to cover possible production problems and diversion of supply from one pipeline to another and as a result of normal declines in production in some producing areas and the attachment of new, replacement supplies in other areas. See Comments of the Natural Gas Supply Association and Indicated Producers, FERC Docket RM91-11-000, at 39-44, (October 15, 1991).


121. 19. This can be a particularly contentious process.


125. 23. It will also be important to know when a cost must be incurred. If the LDC does not have equipment to allow it to measure "real time" takes, available storage for "swings" may not be sufficient to avoid "real time" penalties. Additionally, even if the LDC has the measurement capabilities, access to those capabilities on a "real time" basis must be allowed to those who need to adjust their operations to accommodate unplanned changes. The latter circumstance would be of particular importance to an aggregator with responsibility to dispatch gas on the pipeline and into and out of storage.

126. 24. Of course, if the cost of storage use is greater than the anticipated change between seasonal prices, arbitrage is less attractive and storage may be shed by those with relatively flat load factors.

127. 25. For instance, if a storage facility is accessible through more than one pipeline, an individual allocation of that storage will allow a shipper with rights on a second pipeline to avoid using the facilities of the first to get its gas to storage. If the second pipeline is cheaper, or if the shipper has what would otherwise be idle capacity on the second pipeline, economic efficiencies can become significant.


129. 27. A brewing competitive issue relates to the use of third-party storage accessible off a given pipeline. The pipeline may forgo a second transportation charge if the storage is its own and the gas never leaves its facilities. However, when the storage belongs to another and the gas leaves the system to return later, some pipelines have proposed to charge twice. One pipeline agreed to charge...
once, foregoing a second charge if the shipper could prove that its transmission rate was paid when the gas went to the third-party storage facility. Tennessee Gas Pipeline Co., Order Preliminarily Approving Settlement, 57 FERC ¶ 61,360 (1991), order on reh'g approving settlement as modified, 59 FERC ¶ 61,045 (1992).

130. 28. Order No. 636 at 30,427.

131. 29. "Cycling" means that virtually all gas injected during the summer injection season is removed by the end of the winter withdrawal season.

132. 30. Order No. 636 at 30,421.

133. 31. In this regard, Texas Eastern Transmission Corporation in its June 8, 1992, Order No. 636 Compliance filing, FERC Docket No. RS92-11, has proposed that it be allowed to borrow gas in storage to meet no-notice needs, subject to rapid repayment from the customers who needed the gas. This raises a host of liability issues if the customer cannot repay the pipeline on schedule.

134. 32. See Texas Eastern Transmission Co.'s June 8, 1992 Order No. 636 compliance filing, FERC Docket No. RS92-11-000.

135. 33. See Algonquin Gas Transmission Corp., Summary of Order No. 636 Compliance dated May 15, 1992, FERC Docket No. RS92-28-000. Algonquin proposes that F-1 and WS-1 customers will be allowed no-notice service provided suitable no-notice upstream pipeline arrangements are in place and functional.


137. 35. As a practical matter, the unbundling of gathering services can result in substantial economic dislocation, particularly where relatively expensive systems were constructed when gas was scarce. Those who have relied on relatively cheap gathering service and must now pay its full cost will find themselves having to adjust to substantially different and, perhaps debilitating, economics. The availability of contractual "outs" will likely depend on the wording of individual contracts. For an example of potential impacts, see Panhandle Eastern Pipe Line Company's February 21, 1992 tariff filing which proposed to unbundle gathering services from transportation services on its Wattenburg system, FERC Docket No. RP92-120-000.

138. 36. Order No. 436 at 31,496 required gathering rates to be separately stated but this was not interpreted to mean that the service would be unbundled. Ultimately, FERC allowed that separately stating the gathering component of a bundled transportation rate on tariff sheets was sufficient. Caprock Pipeline Co., 36 FERC ¶ 61,105 (1986).

139. 37. The answer for a particular party will depend on whether it utilizes a lower-cost, higher-throughput portion of the overall system than the system-average, in which case that party would effectively subsidize the higher costs systems.


142. 40. See Panhandle Eastern Pipe Line Co., 40 FERC ¶ 61,369 (1987) where the Commission accepted, subject to refund, Panhandle's proposal to reclassify approximately $400 million in gas plant costs from gathering to transmission costs.


144. 42. The Commission provides somewhat confusing guidance here:

The instant rule will not address functionalization, which is mainly important in determining whether facilities are jurisdictional or nonjurisdictional. The Commission will continue to functionalize between transportation and gathering based on the modified Farmland test. The present focus is on classification as it relates to allocation and to the designing of the actual rates.

Order No. 636 at 30,431-32 (footnotes omitted).

146. In *Northwest Pipeline Corp.*, 59 FERC ¶ 61,115 at 61,436 (1992), the Commission indicated that, if circumstances develop that would allow Williams to exploit its position as a pipeline affiliate to engage in anticompetitive activity, a need for regulation may arise. In that event, the Commission stated, it may exercise its authority to regulate one or more of the rates, terms, and conditions for service on the abandoned facilities.

147. Order No. 636 at 30,417.

148. In its Order No. 636 compliance proposal, FERC Docket No. RS92-28-000, Algonquin Gas Transmission Co. indicated that it needed to retain 80 MMcfd of upstream capacity for, among other things, (1) line maintenance, (2) peak day compressor fuel, (3) unaccounted for gas, (4) peak day heater fuel, and (5) line pack management. In these circumstances, there is tension between the pipeline's need to maintain its system operations and shippers' rights to equality in services.


150. Order No. 636 at 30,435-36. There, the Commission stated that it "recognizes that the use of SFV, without any adjustments, could result in cost shifting among customer classes." Thus, pipelines must file information consisting of a comparison of the revenue responsibility of each customer class for the unbundled services under (1) the pipeline's last approved cost classification method for cost allocation and rate design, and (2) the SFV cost classification method for cost allocation and rate design. If the comparison shows that adopting SFV will result in a 10% or greater increase in revenue responsibility for any customer class, FERC will require the pipeline to develop and implement a plan to phase-in the rate increase over no more than 4 years.

151. Id.


153. This may not be a great revenue producer, as small customers deal in small volumes and, likely, would be able to reassign only when large amounts of other firm capacity are also available for assignment.

154. For example, if small customers can band together to use their overall capacity rights flexibly, they may, by virtue of their diversity, be able to shed some capacity during peak periods when it is more valuable to the markets.


156. A backhaul is transportation of gas by displacement against the flow on a single pipeline, so that the gas is redelivered upstream of its point of receipt.


158. For instance, no fuel is used for backhaul transportation.

159. This could occur, for instance, through the use of large geographic zones when mileage-based rates would result in a much lower rate for the typically short pipeline-to-pipeline hauls in the production area. Even pipelines that use mileage-based rates may charge an "access" rate just to get on the system, thus achieving the same impact. See Panhandle Eastern Pipe Line Co., Notice of Rate Change, FERC Docket No. RP92-166-000, Volume I, Revised Tariff Sheet Nos. 3-F, 3-G, 3-H, 3-I (filed May 1, 1992).

160. The former concern can be mitigated by FERC simply defining "exit" fees as those applicable when a customer leaves the system entirely, not when it just leaves the merchant service. In that case, a firm demand charge could be applied, e.g., to former sales customers (now firm shippers), to create a purchase-decision-neutral fee.
See Natural Gas Pipeline Co. of Amer.'s proposed tariff sheets to establish an exit fee, FERC Docket No. RP92-156-000 (filed April 23, 1992). Protests to the proposal included arguments that (1) Natural's unilateral exit fee violates Order No. 636 because there the Commission contemplated that exit fees are to be negotiated by the pipeline and its customers in the context of the restructuring proceedings, and (2) since Natural also has a currently effective gas inventory charge, the exit fee will result in two potentially overlapping mechanisms for recovering gas costs. Parties also protested several specific features of the exit fee, such as the design of the supply reassignment mechanism and the calculation of the exit fee. (Order Accepting Tariff Sheets as Pro Forma Sheets and Redocketing Filing, Issued May 29, 1992).

161. 1. Order No. 636 at 30,415. Pipeline tariffs are required to set forth methods for allocating aggregate receipt point capacity, individual receipt point capacity, mainline segment capacity, storage capacity, and delivery point capacity.

162. 2. See e.g., Northern Natural Gas Co., 52 FERC ¶ 61,296 (1990).

163. 3. For instance, if firm shippers using secondary points can "bump" interruptible service at will, interruptible shippers will have less ability to arrange alternative supplies than if, for instance, they have notice 24 or 48 hours before being "bumped."

164. 4. Order No. 636 at 30,415.


166. 6. Order No. 636 at 30,415.

167. 7. See, e.g. MIGC, Inc., 39 FERC ¶ 61,030 at 61,084 (1987). The Commission rejected a preference for firm sales over firm transportation.

168. 8. The shift to SFV is, at least in part, motivated to prod those with excess capacity to shed it. See Columbia Gas Transmission Corp., 57 FERC ¶ 61,250 (1991), discussing Columbia's open-access off-peak firm transportation service (Rate Schedule OPT) and Columbia Gas Transmission Corp., 57 FERC ¶ 61,133 (1991), discussing Columbia's ITS Rate Schedule under which interruptible capacity during the winter season is allocated each month to the shippers bidding the highest price, up to a cap of the 50% load factor derivation of the FTS rate.


170. 10. This cooperation was not necessary when everyone was buying from the pipeline, as the pipeline could simply enforce its end-use curtailment plan.

171. 11. Order No. 636 at 30,430.


175. 15. Natural Gas Pipeline Co. of Amer., 39 FERC ¶ 61,153 (1987).

176. 16. This resulted, in large part, because pipelines could not monitor imbalances and scheduling variance at any where near the timeliness necessary to provide adequate warning to allow shippers to change their operation. See Northern Natural Gas Co., 50 FERC ¶ 61,256 (1990).


179. The subjects of imbalances and allocations could be the subject of a separate treatise. This section, however, will only attempt to introduce the reader to general concepts. Contract drafters should take the time to pursue all the implications of tariff provisions dealing with these issues, as significant penalties could apply for those who unwittingly end up responsible for causing imbalances or scheduling deviations.


181. OBAs are necessary to establish contractual privity between the holder and the pipeline. The jurisdictional status of OBAs is subject to debate. See Tennessee Gas Pipeline Co., 56 FERC ¶ 61,463 (1991). Ultimately, pipelines likely will include pro forma OBAs in their tariffs.

182. This theory is subject to criticism if the pool is spread over so wide a geographical area that a "long" at one point does not actually make up for a "short" at another. The most likely situations have the longs and shorts occur on two geographically separated legs of a system. The solution is to create pools on each leg.

183. Order No. 636 at 30,415.

184. In fact, the idea for receipt point OBAs was really a take-off on pipeline OBAs.

185. The need to know will give rise to issues of confidentiality if shippers want to see the allocation methodology at each point at which they move supply. Suppliers serving numerous markets are likely to want to keep those markets from knowing their relative position in the supply queue.

186. It bears noting that most of the terminology in this section is still evolving, and misuse is flagrant. Thus, one must question what exactly the other party means when referring to, e.g., imbalances. These generally refer to actual "in and out" variations, but the term has also been used to describe variations from scheduled volumes.

187. No gas would actually flow, although rate adjustment may be necessary to account for imbalances, e.g., in different rate zones.

188. For instance, if pooling points are established only in production areas (and rate zone boundaries are established at these points), the economics of bringing gas onto a system at a market area versus a production area interconnect could vary widely.

189. This could occur, for instance, if a pipeline requires notice well in advance of "bid week" when monthly transactions are executed.

190. Such a portfolio could, for example, be made up 1/3 of long-term contracts, 1/3 of medium term, and the remainder of spot purchases. If restrictions on aggregation make spot purchases and transportation under firm contracts difficult, this may force LDCs to abandon the spot portion of their portfolios at least.

191. This could be driven, e.g., by a rate structure that imposes different production area IT and FT rates for feeder agreements. For example, Transcontinental Gas Pipe Line Corp.'s pooling mechanism requires all shippers to use IT Feeders to move gas from production area well-head receipt points to the FT receipt points at mainline compressor stations; all shippers must pay both an IT feeder and an FT rate. Transcontinental Gas Pipe Line Corp., 55 FERC ¶ 61,446 at 62,347 (1991). Under Transco's feeder plan, FT service to the wellhead is not a structural option. Id. at 62,361.

Conversely, in a settlement proposal filed March 10, 1992, FERC Docket No. RP89-161 et al., ANR Pipeline Co. proposes two types of pooling agreements; one to serve longhaul (i.e., from the wellhead or interconnects in the supply area) firm transportation contracts downstream of the Eunice and Greenburg headstations, and one to service interruptible agreements.


193. 1. Id. at 30,416-17.

194. For instance, a flat fee may defer small-volume releases while a volumetric fee may overly burden large transactions when compared to the administration cost.

196. 2. Order No. 636 at 30,460. In practice, a number of pipelines have proposed to defer these costs for collection in their next general NGA § 4 rate filing.

197. 3. For instance, a pipeline may agree to a cost-based GIC that would credit some sales revenues to paying down the existing PGA balance. This could impact nominations for sales service. See Natural Gas Pipeline Co. of Amer., 49 FERC ¶ 61,137 (1989).

198. 4. It will not spell the end of retroactive surcharges for other rates, however, as the the District of Columbia Circuit recently ruled. See Natural Gas Clearinghouse v. FERC, Case No. 90-1367, (D.C. Cir. May 22, 1992). Either supply contracts should spell out responsibility for surcharges, or shippers should try to protect themselves by negotiated rate caps.


200. 6. E.g., should the pipeline be able to collect Transition Costs for dealing with above-market contracts while retaining below market supplies in its portfolio?

201. 7. Questions have been raised whether contracts that are not market responsive should be protected as "competitively sensitive."

202. 8. Prudence challenges have been asserted as a reason for pipelines to try to negotiate low-cost settlements with suppliers. See testimony related to Order No. 636 transition costs before the House Energy and Power subcommittee as reported in Gas Daily on July 9, 1992. This reference relates to incentives provided with respect to realignments, not to the entering into contracts in the first instance or their more recent renegotiation.

203. 9. If a shipper uses interruptible transportation and is not willing to pay volumetric surcharges, it can try to find alternative means of transporting supplies. In contrast, the firm shipper must pay demand charges for the term of its agreement and does not have this option.

204. 1. Order No. 636 at 30,383.

205. 2. The Commission may have taken some of the wind out of the sail of challengers by establishing discovery procedures under which those wishing to engage in a thorough review of the pipelines' filings can seek information related to that review. See Order Granting Motion in Part, Docket No. RM91-11-000, 59 FERC ¶ 61,351 (1992).

206. 3. See e.g., Associated Gas Distrib. v. FERC, 893 F.2d 349 (D.C. Cir. 1989); Transwestern Pipeline Co. v. FERC, 897 F.2d 570 (D.C. Cir. 1990). Here, petitioners challenged, among other things, various aspects of Order No. 500's take-or-pay recovery mechanisms.

207. 1. For instance, minimum bills and take-or-pay provisions are likely to find their way into contracts either as demand or deficiency-based "inventory" charges.

208. 1. Order No. 636-A is over 440 pages long. We deal here with only its most significant aspects. Citations are to the commission's Mimeo version of Order No. 636A, dated Aug. 3, 1992.

209. 2. Mimeo at 72-73.

210. 3. Id. at 81.

211. 4. Id. at 91.

212. 5. Id. at 104.

213. 6. Id. at 113.

214. 7. Id. at 110.
215. 8. Id. at 117.

216. 9. Id. at 118.

217. 10. Id. at 117-118. The same rules will apply with respect to upstream storage retained to support the merchant service. Id. at 154.

218. 11. Id. at 68.

219. 12. Id. at 70.

220. 13. Id. at 130. The Commission skirted an issue concerning the possibility that a pipeline would "borrow" IT gas to serve a no-notice customer. Instead of a flat prohibition against borrowing other than under a contract, the Commission deferred the issue to individual proceedings and expressed its general belief that borrowing should be "pursuant to contract and appropriate compensation." Id. at 145.

221. 14. Id. at 133.

222. 15. Id. at 138. Thus, a customer that had converted some, but not all, of its bundled sales service to firm transportation could arguably request no-notice service for its entire entitlement, not just that formerly associated with pre-Order No. 636 purchases.

223. 16. Id. at 141.

224. 17. Id. at 152.

225. 18. Id. at 156.

226. 19. Id. at 57.

227. 20. Id. at 57, 244, 260-261.

228. 21. Id. at 287, 300-306.

229. 22. Id. at 312, 317.

230. 23. Id. at 294.

231. 24. Id. at 346.