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Report to Congressional Requesters

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Costs, Benefits, and Concerns Related to FERC's Order 636

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Congressional Requesters

Since the late 1970s, the Congress and the Federal Energy Regulatory Commission (FERC) have taken a number of steps to lessen federal regulation of natural gas markets and to make the industry more competitive. For example, the sale of natural gas at the point of production was deregulated and the interstate pipeline companies were encouraged to transport gas supplies that customers purchased directly from the producers, as well as gas purchased from the pipeline companies. FERC's latest action in this regard, Order 636, is intended to continue the evolution toward a more open and accessible pipeline system for buyers and sellers of gas. Among other things, the order requires many interstate pipeline companies to offer their customers transportation, storage, and other services separately or as part of a "bundled" package by the 1993 winter heating season. The pipeline companies will be allowed to recover from their customers the costs that can be directly attributed to the new regulation as long as FERC determines these costs were prudently incurred. These costs include the cost of terminating or modifying existing gas supply contracts and other transition costs of implementing the new order.

Because the pipeline companies still retain a monopoly over the transportation of natural gas, FERC will continue to regulate the rates the companies can charge. However, Order 636 changes how FERC sets, or designs, the pipeline companies' transportation rates. Under the new rate design, customers that require "firm," or uninterrupted, service will pay more of the pipeline companies' fixed costs; these customers are mainly local distribution companies that serve residential or commercial end-users. Customers that can tolerate "interruptible" service could pay a smaller percentage of these costs; these customers are mainly industrial customers, such as manufacturers of fertilizer, glass, and other consumer products, linked directly to the pipeline companies or distribution companies that serve industrial end-users. To the extent that industrial businesses pay less for their delivered gas supplies, consumers—including residential and commercial end-users of natural gas—could receive an indirect benefit by paying less for the consumer items these businesses produce.

Concerns have been expressed by Members of Congress and the industry about the costs and benefits of FERC's new order and, in particular, about the potential impact of the order on residential end-users, who may see the price they pay for gas increase. As requested by your offices, we agreed to (1) estimate the potential shift in fixed costs among pipeline customers resulting from the change in the way transportation rates are designed, (2) report the pipeline companies' estimates of the transition costs of implementing the new rule, and (3) summarize available information on the benefits of the new order and the costs and benefits attributable to changes in legislation and FERC regulations implemented since 1978 to lighten federal regulation of the industry.

To estimate the potential cost-shifts, we performed two analyses. First, using the total fixed costs of the pipeline industry in 1990, we estimated the nationwide shift in costs from customers with interruptible service to customers with firm service resulting from the change in rate design. Second, we performed case studies on five individual pipeline companies to estimate how the change in rate design may affect the gas bills paid by residential, commercial, industrial, and electric utility end-users. (For more details on our methodology for this and the other two objectives of our review, see app. VII.)

Results in Brief

The amount of fixed costs that will be shifted among the distribution companies and their end-users cannot be determined with precision until after Order 636 has been fully implemented. Nonetheless, based on our analysis of the total fixed costs of the pipeline industry, our best estimate is that Order 636's mandated change in rate design could shift about $1.2 billion per year nationally in the pipeline companies' fixed costs (about 11 percent of such costs) to customers that require guaranteed delivery of gas, such as residential end-users. Our estimate is $400 million higher than FERC's estimate of $800 million, primarily because we used what we believe to be more appropriate assumptions about distribution companies' purchases of interruptible service and discounts on such service offered by the pipeline companies.

Furthermore, on the basis of our case studies of five pipeline companies serving the eastern seaboard, we found that the change in rate design will affect end-users differently. For example, depending on how the distribution companies allocate changes in costs to their end-users, and without mitigation measures, residential end-users could see increases in their gas bills of up to 9 percent, while nonresidential end-users served by many distribution companies could experience decreases of as much as 7 percent. The results of our case-study analysis cannot be generalized nationwide. The actual cost-shift for the local distribution companies served by these pipeline companies, as well as those in other regions of the country, will depend on many factors. These factors include (1) the fixed costs of the pipeline companies, (2) the distribution companies' utilization of their reservations of pipeline capacity, (3) measures prescribed by FERC in Order 636 or adopted by the pipeline companies to mitigate the cost-shifts, and (4) actions taken by the state and local authorities that approve the rates the distribution companies can charge their end-users.

According to the pipeline companies' preliminary estimates, the transition costs of implementing the new order are about $4.8 billion. This estimate includes, among other things, the costs of (1) terminating or modifying existing contracts to purchase gas supplies (the largest category); (2) abandoning equipment that is no longer needed; (3) closing out unpaid balances on gas supplies that the pipeline companies previously sold to their customers; and (4) purchasing required new equipment, such as computers and meters to track the flow of natural gas. According to FERC, it has not received, and thus has not included in this total, some pipeline companies' estimates. Order 636 allows the pipeline companies to recover 100 percent of these transition costs. The vast majority of these costs will be collected from customers with firm service and the remainder from customers with interruptible service. About $300 million represents new costs to society, such as costs for new equipment, that would not have been incurred without Order 636. Most of the remaining costs would have been paid by the pipeline companies' customers over time in any event.

With the exception of officials representing small municipal distributors, industry analysts generally agree that Order 636 is needed to continue the increases in efficiency and competition achieved by previous statutory and regulatory initiatives. However, the benefits of Order 636 cannot be estimated with certainty until the order has been implemented. FERC estimated that these benefits will exceed the costs by between $2 billion and $6 billion per year on average.[1] Although Order 636 may produce net benefits, we question FERC's estimate because it is based on various independent projections of increased gas use that did not consider the effects of Order 636. We found no other studies that estimate the net benefits of the new order. The extent to which benefits accrue to the gas industry, end-users, or society as a whole will depend, in part, on how the various concerns about Order 636 are resolved. These concerns include the effects of the new rate design; the extent of the transition costs (and

[1]Costs and Benefits of the Final Restructuring Rule, FERC, Office of Economic Policy, Spring 1992, p. 3.

the question of who will pay such costs); and the potential impact on the reliability of service, particularly service to the distribution companies serving small communities.

Background

Before previous FERC actions and Order 636, distribution companies purchased gas supplies and all related transportation and storage services as a bundled package from the interstate pipeline companies. In 1985, FERC issued Order 436, which enabled the distribution companies to purchase gas directly from producers and pay the pipeline companies to transport the gas. According to FERC, however, the pipeline companies retained a competitive advantage over the producers in gas sales because of their ability to combine transportation, storage, and other services in order to provide more reliable service. By requiring the pipeline companies to sell gas, transportation, storage, and other services separately, Order 636 seeks to remove the pipeline companies' competitive advantage. (See app. I for a more detailed discussion of the evolution of natural gas regulation.)

Pipeline companies' services are sold on either a firm or interruptible basis. Firm service, which is primarily purchased by distribution companies on behalf of residential and commercial end-users, guarantees the delivery of gas, particularly during periods of peak demand on the pipeline system, such as cold winter days. In contrast, interruptible service, which is primarily purchased directly by industrial customers or by distribution companies on behalf of industrial end-users, is subject to curtailment or interruption. This kind of service is generally used by those who can switch to other fuels when their gas deliveries are interrupted. Because firm service is more reliable, it is generally priced higher than interruptible service.

Pipeline companies recover the cost of providing their services by assessing two charges: (1) a commodity or usage charge—a fee determined by the volume of gas transported—and (2) a demand or reservation charge—a fee for the customer's right to reserve capacity on a pipeline company's system during periods of peak demand. Customers with firm service pay both a commodity and a demand charge because they receive gas supplies and reserve pipeline capacity. Customers with interruptible service pay only a commodity charge, since they do not reserve pipeline capacity.

The commodity and demand charges FERC approves for each pipeline company allow the company to recover its costs of providing service and to earn a reasonable profit. The method by which the company's costs are applied to either the commodity or demand charge is commonly referred to as rate design. Technically, FERC may apply any costs to either the commodity or the demand charge. However, the variable costs associated with gas supplies and transportation are always applied to the commodity charge. Historically, pipeline companies' fixed costs—such as the depreciation of the pipeline, operation and maintenance expenses, and return on equity—have been distributed between the commodity and demand charges in several ways, depending on FERC's policy goals.

Since 1983, most pipeline companies have recovered their costs under a "modified fixed variable" rate design, which assigns the pipeline companies' return on equity and related taxes to the commodity charge and all other fixed costs to the demand charge.[2] In Order 636, FERC adopted a "straight fixed variable" rate design, which allocates 100 percent of the fixed costs to the demand charge. The greater the proportion of the pipeline companies' fixed costs included in the demand charge, the more these costs are paid by customers with firm service. However, customers with interruptible service will continue to be billed a portion of the fixed costs under the new rate design because the rate for interruptible service is based on the demand charge.[3] FERC made this change in rate design to eliminate fixed costs from the commodity charge, so that the commodity charge would more directly reflect the market price of gas supplies and, as a result, promote increased competition among gas suppliers. (See app. II for a detailed discussion of how rates are designed.)

Before Order 636, FERC performed a review of many pipeline companies' rates at least once every 3 years. Order 636 eliminates this regular triennial rate review. FERC will continue to conduct such reviews when the pipeline companies file for new rates. Furthermore, under section 5 of the Natural Gas Act, FERC—on its own initiative or upon the complaint of a distribution company, a municipality, or a state authority—can still review a pipeline company's rates at any time to determine whether they are just and reasonable.

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[2]According to the Interstate Natural Gas Association of America, the return on equity and associated taxes represent about 15-20 percent of a pipeline company's fixed costs.

[3]Customers with firm service and customers with interruptible service each pay a portion of the fixed costs allocated to the demand charge. The percentage paid by customers with firm service is based on their total reservations of pipeline capacity. Customers with interruptible service pay on the basis of their projected annual gas use during a test period of 9 months.

Cost-Shift Estimates and Possible Effects of the New Rate Design

We estimate that about $1.2 billion in fixed costs could be shifted nationwide annually as a result of the change in rate design. FERC and officials representing distribution companies arrived at different estimates but used different assumptions. Our review of five pipeline companies indicates that the cost changes experienced by distribution companies and their end-users are likely to vary. Actions taken by FERC, the states, and local authorities may influence the extent to which such cost-shifts will occur. However, some in the industry are concerned about the pipeline companies' incentives to control costs under the new rate design.

Estimates of the Cost-Shifts Differ

Our estimate of the nationwide shift in costs resulting from FERC's adoption of the straight fixed variable rate design is higher than FERC's estimate but not as high as what some in the industry project. We estimate that without the mitigation measures discussed below, about $1.2 billion in costs could be shifted annually from customers with interruptible service to customers with firm service. As a result of this cost-shift, customers with firm service would pay about 76 percent—up from 65 percent—of the pipeline industry's total fixed costs of about $11.4 billion. Customers with interruptible service would pay about 24 percent of these fixed costs. As discussed below, the actual cost-shift depends upon a number of factors, such as the cost mitigation measures that are adopted, the amount of interruptible transportation that is purchased after Order 636 is implemented, the price that the distribution companies receive for the unneeded pipeline capacity reservations they sell in the secondary market provided for in Order 636, and the formula that FERC uses to calculate rates.

In contrast to our estimate, a coalition of several municipal distributors estimated an annual cost-shift of $4.3 billion. We believe the coalition's estimate is too high because it is based on incorrect data on the pipeline companies' revenues. In addition, the estimate incorrectly presumes that customers with firm service pay all of the pipeline companies' fixed costs.

FERC estimated that the proposed change in rate design could annually shift about $800 million in fixed costs from customers with interruptible service to customers with firm service. FERC's estimate is lower than ours because FERC implicitly assumed that the distribution companies purchased interruptible transportation service (in order to obtain lower-cost gas supplies) solely on behalf of their customers with firm service. In contrast, on the basis of our discussions with industry officials, we believe that distribution companies purchase most of the interruptible service they buy on behalf of end-users that have the ability to switch to alternative fuels; these end-users include industrial businesses and electric utilities. Also, FERC did not adjust its estimate to account for the price discounts the pipeline companies offered for interruptible service. Such price discounting has become a common practice in the industry and may increase under Order 636. Discounting the price of interruptible service would lower the revenues (and thus the amount of the pipeline companies' fixed costs) paid by customers with interruptible service. (See app. III for a more detailed discussion of the estimates of total cost-shifts.)

Cost-Shifts Will Affect End-Users Differently

Although the nationwide cost-shift may not be as large as some had feared, not all distribution companies and their end-users will be affected equally. The changes in end-users' gas bills will depend, in part, on how distribution companies allocate the changes in gas costs resulting from FERC's change in rate design.

For example, our analysis of the change in rate design for five judgmentally selected interstate pipeline companies indicates that, without cost mitigation measures, the gas bills of residential end-users served by local distribution companies with a high concentration of residential and small commercial end-users (i.e., customers with firm service) may increase by 1 to 9 percent.[4] In contrast, residential end-users served by distribution companies that also serve a high concentration of nonresidential end-users may experience a change in the price they pay for delivered gas ranging from a 3-percent decrease to a 3-percent increase.[5] We also estimated that the industrial and electric utility end-users served by more than 80 percent of the distribution companies in our analysis could experience a 3-percent to 7-percent decrease in their gas bills.[6] (See app. III for a detailed discussion of our review of the cost-shifts for distribution companies and the end-users they serve resulting from FERC's change in rate design alone and other changes in Order 636.)

[4]Each estimate in our case-study analysis refers to the change we calculated in the gas bills of the end-users of a single local distribution company. For example, the 9-percent increase mentioned above is the change we calculated for the residential customers of a particular distribution company. Our estimates cannot be generalized to other distribution companies and their end-users.

[5]These results assume that the distribution companies will assign all changes in costs resulting from the change in rate design to residential end-users.

[6]These results assume that the distribution companies will assign costs as they are incurred by each class of end-user.

Several Factors Will Affect the Magnitude of the Cost-Shift

The final amount of the pipeline companies' fixed costs that will be shifted cannot be determined with any degree of precision until Order 636 has been implemented. The ultimate shifts in costs among the distribution companies and the end-users they serve will depend on several factors. For example, under Order 636, distribution companies will be able to release for resale on the secondary market any unneeded reservations for pipeline capacity. In order to recoup the increased costs resulting from the new rate design, the distribution companies may resell unneeded capacity in this market at any price up to a cap—the price that a pipeline company could have charged a distributor for the capacity under rates approved by FERC. It is not yet clear how well this market will work to reduce the distribution companies' costs and to ration capacity to those who value it most. Also, FERC is requiring the pipeline companies to take steps that will limit the cost increase to any distribution company to a maximum of 10 percent per year after Order 636 is implemented. FERC suggested that the pipeline companies might be able to mitigate cost-shifts by exempting certain small distribution companies from demand charges and by using seasonal contracts that allow the distribution companies to reduce their reservations for pipeline capacity during the summer months.

Because state and municipal authorities approve or establish the transportation rates the distribution companies can charge their end-users, these authorities can also have an impact on the final price a consumer pays for gas and thus on the ultimate cost-shifts. These authorities may be reluctant to mitigate any cost increases to residential end-users by raising rates for end-users with interruptible service (generally industrial businesses) because customers with interruptible service may (1) switch to an alternative fuel, (2) bypass the distribution company and hook up directly to an interstate pipeline, or (3) relocate their businesses to another area. In each of these cases, once an industrial end-user stops receiving gas, residential and commercial end-users served by the same distributor are left to pay an even larger portion of their pipeline company's fixed costs.

New Rate Design Has Raised Several Concerns

Some industry analysts are concerned that, under the new rate design, the pipeline companies may be guaranteed recovery of their fixed costs, including their profits. These analysts believe that FERC should lower the pipeline companies' approved rates of return to reflect the lower risk under the new rate design. Some analysts also believe that if the pipeline companies are guaranteed recovery of all their costs, they will have less incentive to control costs or maximize the amount of gas they transport.

These analysts are also concerned that the new rate design may not be appropriate for those pipeline companies that do not operate at full capacity. If a pipeline company has substantial excess capacity, its customers with firm service will pay a disproportionate amount of the company's fixed costs, even though this service may not be of greater value than interruptible service. In addition, officials of distribution companies and consumer advocacy groups are concerned that because FERC eliminated its triennial review of the pipeline companies' costs, the pipeline companies may be able to earn excess revenues on a depreciating rate base before FERC reviews their rates again.

In response to these concerns, FERC contends that the pipeline companies are not guaranteed full recovery of their fixed costs because a portion of these costs will still be recovered through the rates for interruptible service. If a pipeline company sells less interruptible service than it projected when its rates were set, the company will not recover a portion of its fixed costs.[7] Also, FERC has indicated that it will consider changes to the pipeline companies' allowed return on equity to reflect any lower risks they may face, other things being equal. In addition, FERC notes that the increased competition among pipeline companies that Order 636 promotes, particularly in markets served by more than one pipeline company, will tend to keep costs in check. FERC has also stated that it is not requiring the pipeline companies to adopt the new rate design if the design is inappropriate for their company. FERC will also continue to review and approve each pipeline company's costs when the company requests new rates. Finally, FERC says that it will continue to consider petitions from affected parties for reviews of the pipeline companies' rates. These issues are still being debated. (See app. II for a detailed discussion of the major issues associated with the change in rate design.)

Transition Costs, Other Costs, and Service Reliability Issues Arising From Order 636

Seventy-six pipeline companies have filed estimates with FERC to recover the transition costs of implementing Order 636. The majority of these costs result from changes to existing contracts for gas supplies. Officials of state public utility commissions, distribution companies, and consumer advocacy groups have collectively expressed concerns about the apportionment of these costs, the costs the distribution companies may incur for services that the pipeline companies formerly provided, and

[7] FERC acknowledges that the new secondary market in released capacity may lead to a significant decrease in the amount of interruptible service customers purchase. If the amount of interruptible service decreases, the pipeline companies will recover a larger portion of their fixed costs through their demand charges. As a result, the portion of their fixed costs they are guaranteed to recover will likely increase the next time the pipeline companies receive new rates from FERC.

potential service disruptions. However, FERC believes, among other things, that the flexibility provided by greater competition and the secondary market for released pipeline capacity will ensure that gas supplies and transportation service are reliable.

The Majority of Transition Costs Are Transfer Payments Among Industry Segments

According to FERC, the pipeline companies' estimates of transition costs as of July 21, 1993, total about $4.8 billion. FERC believes that this figure represents the majority of the costs, even though 24 pipeline companies had not reported all such costs to FERC. Transition costs include the costs incurred by the pipeline companies to (1) realign (terminate or modify) existing gas supply contracts with producers, which were entered into on behalf of customers that purchased gas from the pipeline companies but that will now deal directly with the producers or other sellers; (2) abandon equipment, such as storage facilities, that are no longer necessary because of Order 636; (3) close out unpaid balances on gas supplies that the pipeline companies previously sold to their customers; and (4) purchase required new equipment, such as gas metering stations and electronic bulletin boards that show available transportation capacity and other data.

Under the order, the pipeline companies will be allowed to recover 100 percent of the transition costs from their customers—mostly from customers with firm service, such as distribution companies. We estimate that the average residential end-user could pay about $21.50 more in the first year after the implementation of Order 636 and about $14 more per year in each of the next 2 years if the distribution companies bill the end-users according to their gas consumption. In the worst-case scenario, if the distribution companies bill all transition costs to residential end-users only, these end-users could pay about $84 more in the first year and about $55 more per year in each of the next 2 years.

About $300 million of the total transition costs represent new costs to society, such as costs for new equipment, that would not have been incurred without Order 636. Most of the remaining costs would have been borne by the pipeline companies' customers even without Order 636. For example, about $3.3 billion of the total transition costs represents the costs to terminate or modify contracts with producers. Had these contracts been modified or terminated under previous FERC orders, which required the pipeline companies to share in such costs, the pipeline companies would have paid 36 percent, or about $1.2 billion, leaving 64 percent, or $2.1 billion, to be paid by the customers. However, according to a FERC official, if such contracts had remained in effect, the pipeline companies would likely have continued to pass most of these costs on to consumers over the life of the contract. (See app. IV for a detailed discussion of the transition costs.)

Industry Participants Have Concerns About the Transition Costs

Officials of distribution companies and state regulators believe that the pipeline companies will have little incentive to minimize the transition costs if they can recover all of these costs from their customers. FERC argues that it will review all transition costs to ensure that they are eligible for recovery under Order 636 and have been incurred prudently. However, it is not yet clear what specific criteria FERC will use for such reviews. FERC also points out that customers will have an opportunity to challenge the pipeline companies' proposed transition costs during FERC's reviews.

Officials of distribution companies and consumer groups believe that the pipeline companies and gas producers should pay a greater share of the transition costs—particularly the costs associated with terminating contracts for gas supplies. However, FERC believes that the pipeline companies' firm-service customers should pay the brunt of these costs because, in its view, the pipeline companies entered into contracts for gas supplies on behalf of their customers. Furthermore, FERC argues that firm-service customers or their end-users will be the beneficiaries of the lower-cost gas supplies that are anticipated in the more market-based, competitive, and efficient market expected as a result of Order 636. For example, FERC estimates that these costs will be offset by more market-based gas prices, resulting in future savings to customers of between $3.4 billion and $8.7 billion.[8] These savings are in addition to FERC's overall estimates of the benefits of Order 636, which are discussed below. Finally, FERC notes that the pipeline companies have already absorbed $3.6 billion in the costs to terminate or modify contracts for gas supplies under previous regulatory actions. FERC's planned allocation of the transition costs and estimates of the savings to end-users continue to be controversial.

Order 636 Will Result in Added Responsibilities for Local Distribution Companies

Local distribution companies will also face new service responsibilities as they acquire and deliver their own gas supplies. These responsibilities may both provide opportunities and entail new costs for the distribution companies. As discussed above, the pipeline companies have provided many distribution companies with the combined or bundled services necessary to meet their end-users' needs for gas supplies. Under Order

[8]We did not review these estimates to ascertain their validity.

636, the pipeline companies are now required to sell these services separately. Thus, distribution companies must obtain their own gas supplies, secure pipeline space for transportation of the gas, acquire storage facilities to cover any short-term shortages, and monitor pipeline systems to determine when to release unneeded capacity. Some larger distribution companies see these new responsibilities as opportunities to shop among several competitive sellers to obtain cheaper gas supplies and transportation services. However, many smaller distribution companies maintain that they lack the resources to shop for the best prices. These smaller companies believe that the pipeline companies could acquire and resell gas supplies, transportation, and storage services at a lower total price than they can secure for themselves. However, other industry analysts contend that smaller distribution companies could pay gas marketers—unregulated buyers and sellers of gas—or producers to provide these services. Distribution companies could also receive these services from a pipeline company as a "rebundled" package.

Distribution Companies Are Concerned About Continued Service Reliability

Some distribution companies that primarily serve residential and small commercial end-users have voiced concerns not only about possible increases in costs to their end-users but also about the potential for service disruptions. After Order 636 is implemented, the pipeline companies will no longer be required to provide the distribution companies with backup gas supplies and transportation services when these supplies and services cannot be obtained from other sources. Instead, the distribution companies will have to depend on the reliability of their contracts for gas supplies and transportation services.

Officials of small distribution companies and consumer advocacy groups that we contacted are concerned that the potential for a supply disruption will increase after Order 636 is implemented because the pipeline companies will have less control over their systems. This reduction in operational control, combined with the growth in the number of buyers and sellers in the marketplace, could increase the potential for transportation bottlenecks or other threats to the delivery of gas supplies. Moreover, FERC will not require the pipeline companies to give residential and small commercial end-users priority over other end-users if transportation capacity is curtailed or disrupted. In the future, a pipeline company may curtail service to each of its customers with firm service on an equal, that is, pro rata, basis.

FERC believes that greater flexibility and, in turn, greater service reliability will result from an increased number of potential sources of gas supplies available to customers, greater choice among the pipeline companies' services, and the secondary market for released pipeline capacity. FERC is also requiring the pipeline companies to submit plans that outline how transportation will be rationed in the event of a curtailment caused by unforeseen events, such as a ruptured section of pipeline. (See app. V for a detailed discussion of the potential new service costs that the distribution companies may have to incur and their concerns about reliable service.)

Benefits of Order 636 and Previous Related Laws and Regulations

While FERC's estimate of the benefits of Order 636 is questionable, industry analysts believe that the industry and society could reap benefits, albeit not equally, because of changes resulting from the order. Some state regulators and officials of distribution companies and consumer advocacy groups believe that residential end-users and small commercial end-users of the distribution companies that serve primarily residential and small commercial end-users are likely to benefit least from the order.

Although the precise benefits cannot be measured until the new order is implemented, the order could increase competition in the natural gas industry in several ways. Similar to the expected impact of Order 636, the overall effect of the changes resulting from preceding but related orders yielded some benefits to each segment of the industry.

FERC's Estimate Is Based on Questionable Assumptions

FERC estimated that Order 636 would save consumers between $15 billion and $42 billion over the 7 years from 1994 to 2000, or an average of between $2 billion and $6 billion per year in 1990 dollars. In its analysis, FERC attributed all the benefits of projections of increased gas use to Order 636, but such projections did not take Order 636 into consideration. Rather, the projections considered other factors that may affect future gas supply and demand. FERC also did not consider the new costs that could result from Order 636, such as the costs discussed above that the distribution companies may incur to obtain gas supplies and transportation services under multiple contracts. Additional costs to society could result if service reliability is diminished. These new costs could reduce the benefits of Order 636.

Precise Benefits of Order 636 Cannot Be Measured at This Time

Because no one has estimated the incremental change in gas use that can be directly attributed to Order 636, it is not possible to estimate the order's incremental benefits. We considered using existing energy and environmental models to estimate the benefits of increased gas use with respect to decreased oil imports, improved air quality, additional domestic employment, and other areas. However, without estimates of the change in gas use attributable to Order 636, we were unable to estimate such benefits. Industry analysts believe that the benefits of Order 636 cannot be quantitatively determined at this time. Since the restructuring of the industry is not complete, there are no models that can reliably estimate what the equilibrium prices and gas quantities will be in the future. Any model's estimates would be based on assumptions about the industry after Order 636 is fully implemented that may or may not be realized.

Order 636 Could Potentially Increase the Benefits of Competition

As stated earlier, Order 636 is considered the next step in the process of increasing competition in the natural gas industry. FERC therefore believes that the order will enhance the consumer choice and system efficiency begun under previous statutory and regulatory initiatives. When individual pipeline services are sold separately, distribution companies will have the freedom to purchase only the services that they desire. When distribution companies can use their reserved pipeline capacity as they choose, they may be able to purchase less expensive gas and transport the gas on the lowest-cost pipeline network. Also, the creation of the secondary market for released pipeline capacity and the new rate design may allow pipeline capacity to be purchased by the customers that value it most.

In addition, some industry financial analysts believe that Order 636 will reduce uncertainty and increase stability for pipeline companies and producers, thereby increasing investors' confidence in these segments of the industry. As a result, these industry segments could attract investment capital for future pipeline system expansions, gas exploration, and drilling. On the other hand, these analysts believe that Order 636 could have adverse effects on investors' confidence in distribution companies' stocks.

Some state regulators believe that Order 636 transfers a significant amount of risk and responsibility from the pipeline companies to the distribution companies. After Order 636 is implemented, the distribution companies will be entirely responsible for obtaining their own gas supplies, transportation, and other services. The risks and responsibilities could be particularly burdensome to smaller distribution companies that primarily serve residential and small commercial end-users. Officials of distribution companies believe that these end-users' gas bills may increase as the distribution companies seek to minimize the risk of disruptions in gas supplies. As a result, these end-users may benefit least from Order 636.

Previous, Related Statutes and Orders Had Various Costs and Benefits

As discussed previously, the Congress and FERC made a number of changes to increase market forces in the natural gas industry before Order 636. While the transition resulting from these changes has been difficult, particularly for the pipeline companies and producers, the overall effect has been of some benefit to each segment of the industry.

Some industry analysts maintain that the end-users have been the primary beneficiaries of the previous initiatives. The deregulation of natural gas prices, combined with related FERC orders that enabled pipeline customers (such as distribution companies) to purchase gas directly from producers, has contributed to lower consumer prices. Between 1984 and 1991, all end-users benefited from the decrease in gas prices, although not to the same degree. The average prices paid by industrial businesses and electric utilities for delivered gas declined by up to 52 percent when adjusted for inflation. The corresponding decline for residential and commercial end-users was 29 percent and 33 percent, respectively. Industrial businesses and electric utilities enjoyed a greater decrease in average prices. Since they primarily purchase interruptible transportation, a larger percentage of their gas bills consists of the cost of gas supplies. Thus, a decrease in the price of gas supplies results in a greater percentage drop in the final price paid by industrial businesses than in the final prices paid by residential and commercial end-users.

Some industry financial analysts believe that the producers and, to a lesser extent, the pipeline companies benefited least from previous FERC regulations to promote open-access transportation.[9] These analysts believe that the regulations created an asymmetry in responsibility between the pipeline companies and the distribution companies. The pipeline companies were required to purchase gas supplies to serve the distribution companies, but the distribution companies were no longer required to purchase a minimum amount of gas from their pipeline companies. As a result, the pipeline companies terminated or modified their existing contracts with producers, a process that is continuing under Order 636 for many of the remaining gas supply contracts. The producers say they realized only about 20 cents on the dollar when the pipeline companies first began to terminate or modify their contracts.

According to FERC, the pipeline companies incurred about $10 billion in costs because of previous regulatory changes. Of this total, the pipeline companies absorbed costs of about $3.6 billion and recovered the

[9]Under open-access transportation of natural gas, a pipeline company must provide transportation service that is equal in quality to each customer, regardless of whether the customer purchased the gas from a pipeline company, a producer, or any other source.

remaining $6.4 billion from their customers. (App. VI discusses the benefits of Order 636 and the benefits and costs of previous, related laws and regulations in detail.)

Observations

Significant questions remain about the economic impacts of Order 636, particularly about the cost of implementing the order; the success of measures to mitigate cost-shifts; and the ability of the distribution companies, particularly those serving small communities, to adjust quickly to the new system and maintain highly reliable service. While many industry analysts agree that, on balance, the order corrects problems in the structure of the industry and could provide benefits to society as a whole as a result of greater competition in the industry, the benefits of Order 636 cannot be quantified with any degree of precision at this time.

FERC took a number of steps to address the concerns raised by the affected parties when it was formulating Order 636. Modifications may still be necessary to address the remaining issues. While a detailed analysis of the issues still being contested was beyond the scope of our review, we can make the following observations on the basis of our work:

- Cost-shifts related to the change in rate design, coupled with the transition costs and costs related to maintaining reliable gas service, will result in increased costs to some end-users, particularly residential end-users served by smaller distribution companies. FERC has proposed mitigation measures to lessen the cost increases, but it is too early to determine how well these measures will work.
- The proposed secondary market may enable a distribution company to resell its unneeded capacity and thus mitigate some of the costs resulting from the change in rate design. However, the cap set by FERC on prices in this market may limit a distribution company's ability to offset the increased costs of reserving pipeline capacity. Moreover, the cap may inhibit the efficient rationing of unneeded pipeline capacity to those who value it most.
- Allowing the pipeline companies to fully recover the transition costs from their customers raises questions about whether the companies will have a strong incentive to minimize such costs. Under this approach, FERC will be relying extensively on its reviews of the transition costs to determine whether the costs are eligible for recovery and were incurred prudently. FERC has not yet established the specific criteria it will use in such reviews.
- Order 636 places new responsibilities on the pipeline companies' customers, particularly small distribution companies, to negotiate

contracts with natural gas suppliers in order to ensure their own supplies. With more buyers and sellers in the marketplace, customers may also face new challenges if bottlenecks arise in the pipeline system or other problems cause curtailments of transportation service.

- FERC's adoption of the straight fixed variable rate design provides the pipeline companies with greater assurance that they will recover their fixed costs. At the same time, FERC's elimination of the triennial review of many pipeline companies' rates places a greater burden on those that pay such costs to challenge the appropriateness of the rates they pay.

Agency Comments

We requested written agency comments from FERC and the Department of Energy (DOE) on a draft of this report. The response from FERC's Chair is included as appendix VIII. Overall, the Chair considered our report to be fair, objective, and well reasoned. The Chair also noted that FERC was committed to limiting cost-shifts resulting from the change in rate design for transportation services. FERC's staff provided additional technical comments. We reviewed these comments and made changes to the report where appropriate.

DOE did not provide written comments on the draft, but we discussed the report with officials from DOE's Natural Gas Analysis Branch in the Office of Policy, Planning, and Analysis and the Energy Information Administration's Office of Oil and Gas. Overall, these officials believed the report to be balanced and useful. Two general areas of concern were that (1) the report did not address whether each of the major regulatory changes in Order 636 furthered competition in the natural gas industry and (2) the letter portion of the report did not sufficiently discuss the methodology we used to estimate the cost-shift resulting from the new rate design. We believe that the report does discuss the effects of Order 636's major regulatory changes on competition. For example, in appendix VI, while the discussion is organized by industry segment rather than by specific regulatory change, each major component of Order 636 is addressed. In addition, we revised the letter portion of the report to explain more specifically the methodology we used to estimate the potential cost-shifts attributable to the new rate design.

We performed our work between August 1992 and August 1993 in accordance with generally accepted government auditing standards. As noted above, appendix VII describes the scope and methodology of our review in detail.

Please call me at (202) 512-3841 if you or your staffs have any questions. Major contributors to this report are listed in appendix IX.

Victor S. Rezendes
Director, Energy and
Science Issues

List of Requesters

The Honorable J. Bennett Johnston
Chairman, Committee on Energy
and Natural Resources
United States Senate

The Honorable John D. Dingell
Chairman, Committee on Energy
and Commerce
House of Representatives

The Honorable Philip R. Sharp
Chairman, Subcommittee on Energy
and Power
Committee on Energy and Commerce
House of Representatives

The Honorable Thomas J. Bliley, Jr.
The Honorable Jim Cooper
House of Representatives

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Abbreviations

AGA	American Gas Association
DOE	Department of Energy
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GAO	General Accounting Office
INGAA	Interstate Natural Gas Association of America
LDC	local distribution company
mcf	thousand cubic feet
MFV	modified fixed variable
NGA	Natural Gas Act
NGPA	Natural Gas Policy Act
NGSA	Natural Gas Supply Association
NRRI	National Regulatory Research Institute
PUC	public utility commission
SFV	straight fixed variable

The Natural Gas Industry and Its Regulation

Understanding the issues surrounding the Federal Energy Regulatory Commission's (FERC) Order 636 requires a basic knowledge of the natural gas industry and how prices paid by the consumer are set. This appendix provides background on the natural gas industry, its services, and its principal customers. It also describes the evolution of the regulation of natural gas, including the major provisions of FERC's Order 636.

The Natural Gas Industry

Delivering natural gas to end-users involves several steps. First, natural gas is located, developed, and extracted from the ground by producers. About 150 interstate pipeline companies then transport the gas, for the most part through a system of underground pipelines, to approximately 1,300 local distribution companies (LDC).[1] In turn, these LDCs resell or deliver natural gas to end-users, mainly residential, commercial, and industrial customers and electric utilities. In addition, some industrial customers and electric utilities obtain gas directly from the interstate pipeline company, bypassing LDCs.

Historically, LDCs purchased most of their gas supplies, transportation, storage, and related services as a "bundled" package directly from interstate pipeline companies. However, since 1984 FERC has taken a number of actions to allow LDCs to purchase gas directly from producers, then transport the gas through interstate pipelines on an open-access basis. Under open access, all customers who purchase a particular service are treated equally, regardless of whether they purchased the gas from the pipeline company, a producer, or a marketer. FERC's Order 636 mandates that all pipeline companies act primarily as open-access transporters of gas, "unbundling" or separating out the price for each individual service they provide. FERC's primary objective in issuing this and other related orders is to facilitate the establishment of a competitive market in gas supplies.

Pipeline Services and Customers

Pipeline companies sell gas transportation services on either a firm or interruptible basis. Firm service guarantees capacity for the delivery of gas, particularly during periods of peak demand on the pipeline system, such as cold winter days. LDCs purchase this service primarily on behalf of residential and commercial customers. These customers generally cannot easily switch to other fuels when gas prices rise higher than the price of other fuels or when gas supplies or pipeline capacity are scarce. As a

[1]About 850 of the LDCs are managed by municipal authorities. The remainder are investor-owned companies that are regulated by state public utility commissions.

result, residential and commercial customers need firm service to ensure that gas will be delivered to their homes or businesses when they need it most. However, they pay a premium for the guarantee that the LDC will provide service on demand.

In contrast, interruptible service is subject to curtailment by the pipeline company or LDC. According to LDC officials, LDCs purchase interruptible service primarily on behalf of industrial and electric utility end-users. These end-users generally have the ability to switch to other fuels when gas supplies or pipeline capacity are limited. According to industry analysts, more than 50 percent of the industrial plants have fuel-switching capability.[2] End-users with fuel-switching capability are willing to purchase interruptible service, and thereby risk their ability to obtain gas during cold periods, because it is generally cheaper than firm service.

The Evolution of Natural Gas Regulation

Historically, FERC has had regulatory jurisdiction over the interstate transportation, sale for resale, and production of natural gas, while state and local authorities set the transportation rates that LDCs charge end-users. Under the Natural Gas Act, as amended, FERC regulates the transportation rates and services provided by interstate pipeline companies. FERC's traditional mandate is to set rates that allow a pipeline company a reasonable rate of return on capital invested while protecting the consumer against paying unreasonable costs. Furthermore, as a result of a 1954 Supreme Court ruling the Federal Power Commission—FERC's predecessor regulatory agency—also regulated the price of natural gas sold by producers in interstate commerce.[3] However, according to industry analysts, federal regulation of natural gas prices led to an abundance of supplies in intrastate markets, which were not subject to federal regulation, and a shortage of supplies in interstate markets. This supply imbalance led to severe supply disruptions in 1970-71 and 1976-77.

Legislation and FERC regulatory initiatives since 1978 have sought to ensure adequate supplies of natural gas by encouraging market forces in the producer segment of the industry and lightening federal regulation over pipeline transportation services in such a way that consumers could enjoy the benefits of a competitive gas supply, or "wellhead market." According to industry analysts, neither the legislation nor the regulatory

[2]Anna Fay Williams and Leonard V. Parent, New Opportunities for Purchasing Natural Gas (Lilburn, Georgia: The Fairmont Press, 1988).

[3]Phillips Petroleum v. Wisconsin, 347 U.S. 672 (1954).

changes were perfectly conceived. Thus, they required modifications, which are discussed later in this appendix.

In response to the supply disruptions of the 1970s noted above, the Congress enacted the Natural Gas Policy Act (NGPA) of 1978 to (1) establish a pricing scheme that encouraged increased production of natural gas, (2) begin the phased deregulation of natural gas prices, and (3) reduce FERC's regulation of natural gas supplies transported between intrastate and interstate pipeline systems. Moreover, the NGPA established a curtailment plan for natural gas supplies that designated residential customers as "high priority" end-users. This designation meant that in the event of a future supply shortage, such customers would be the last to have their supplies cut off. In response to the gas supply shortage, the Congress also enacted the Power Plant and Industrial Fuel Use Act of 1978, which generally prohibited the use of natural gas as the primary fuel in new major fuel-burning industrial businesses and electricity generating facilities.

The NGPA's pricing schemes contributed to increased production activity and significant growth in natural gas supplies. However, according to FERC and industry officials, demand for natural gas, particularly from existing industrial businesses and electric utilities that could switch to other fuels, declined. The officials said that these end-users did not want to pay for the higher-priced natural gas supplies that the pipeline companies were purchasing under long-term contracts with producers.[4] According to some industry analysts and producer officials, many pipeline companies bought large quantities of gas at prices above the market price under long-term contracts (up to 20 years in some cases) because of the perceived scarcity of gas supplies during the 1970s. These contracts required the pipeline companies to take up to 90 percent of the reserves committed under the gas sales contract or pay the producer anyway. According to industry analysts, the pipeline companies had at least three reasons to purchase the costly gas supplies under long-term contracts. First, the pipeline companies resold old gas supplies at regulated prices that were based, in part, on the average price they paid the producers for new gas supplies. As the price the pipeline companies paid the producers for new gas supplies increased, the revenues these companies earned from the sale of each old unit of gas also increased. Second, the pipeline companies were more sensitive to the need to provide reliable supplies to their customers than they were to prices. Third, the financial markets were concerned that,

[4]According to a pipeline company official, in 1983 the price of natural gas at the burner tip—that is, the price paid by the end-user—exceeded the price of residual fuel for the first time in history.

because gas supplies were considered inadequate, the pipeline companies would not be able to sell enough gas to repay their loans.

Market conditions—declining demand coupled with low prices for alternative fuels—caused the producers to begin selling natural gas at lower prices under short-term contracts (typically less than 30 days). The interstate pipeline companies attempted to retain their noncaptive customers who could potentially switch to other fuels, such as industrial businesses, by developing special marketing programs to transport the lower-cost gas that these end-users had purchased directly from the producers. FERC authorized these programs, which essentially permitted the pipeline companies to transport lower-priced gas supplies to their noncaptive customers without providing the same service to LDCs and their captive customers—residential and small commercial customers—who do not have the ability to switch to other fuels. The pipeline companies did not extend the marketing programs to LDCs and their captive customers because the companies had contractual obligations to pay the producers for the higher-priced natural gas supplies. They also had obligations to provide LDCs with gas supplies to meet the needs of their customers. As a result, according to industry analysts, the pipeline companies were able to sell gas to LDCs at prices far above the maximum price that could be charged in a competitive market.

In 1984, FERC responded to this anticompetitive situation by eliminating the requirement that LDCs purchase a minimum amount of their natural gas supplies from the pipeline companies.[5] FERC did not, however, address the pipeline companies' corresponding contractual obligation to purchase gas supplies from the producers for resale to LDCs. Moreover, FERC did not eliminate the special marketing programs because the pipeline companies argued that such programs were necessary to market the large volumes of gas they were obligated to purchase from the producers.

In 1985, the D.C. Circuit Court of Appeals found that FERC had not adequately considered the effect of these programs on captive customers and remanded the rule for further analysis in light of the potential for discrimination between customers.[6] FERC then issued regulations that began a fundamental restructuring of the industry by encouraging the interstate pipeline companies to separate out their traditional package of services and allow all customers, including industrial end-users, electric

[5]FERC Order 380, Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 Fed. Reg. 22,778 (1984).

[6]Maryland Peoples Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985); 761 F.2d 780 (D.C. Cir. 1985).

utilities, and local distribution companies, to (1) purchase competitively priced gas directly from the producers and (2) arrange for separate pipeline transportation services.[7] As a result, customers bought less and less gas from the pipeline companies. However, the pipeline companies were still required to pay the producers for about $10 billion worth of gas supplies they had previously contracted for but were not purchasing. FERC subsequently created a mechanism that enabled the pipeline companies to recover from their customers up to 75 percent of the cost of modifying or terminating their long-term contracts with the producers.[8]

As an additional step to eliminate market distortions, FERC issued regulations that removed the NGPA price caps on gas from wells that were drilled before February 1977.[9] The maximum lawful price set by the NGPA for much of this "old" gas was considerably lower than the current market prices. These regulations also enabled the producers to terminate their contracts with the pipeline companies for these gas supplies and sell the gas to other buyers.

Subsequently, the Congress repealed provisions of the Power Plant and Industrial Fuel Use Act in 1987 to end the prohibition on additional gas use by new industrial businesses and electric utilities and enacted the Natural Gas Wellhead Decontrol Act of 1989 (P.L. 101-60), which mandated that federal controls over natural gas prices would end by January 1, 1993.

However, according to FERC, during periods of peak demand, gas producers were still at a competitive disadvantage in making direct sales to LDCs because the pipeline companies continued to sell gas supplies—along with firm transportation and storage service—to LDCs. Thus, LDCs would purchase most of their gas supplies from the pipeline companies rather than directly from the producers because the distributors did not want to risk interruption in service during these periods.

To correct this competitive imbalance, FERC issued orders 636, 636-A, and 636-B, which together attempt to further the restructuring of the natural

[7]FERC Order 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 50 Fed. Reg. 42,408 (1985).

[8]Order 500, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 52 Fed. Reg. 30,334 (Aug. 1987) and Order 528-A, Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 54 ¶ F.E.R.C. 61,095 (1991).

[9]Order 451, Ceiling Prices: Old Gas Pricing Structure, 51 Fed. Reg. 22,168 (1986).

gas industry and promote greater competition.[10] Major provisions of the rule require or allow the pipeline companies to

- recover their costs of service through the use of the "straight fixed variable" rate design, discussed in appendix II;
- separate, or "unbundle", their services, pricing each service separately;[11]
- provide open-access transportation that is equal in quality for all gas supplies, whether the supplies are purchased from the pipeline company or not;
- allow holders of firm capacity reservations to release excess capacity back to the pipeline company for resale to others, thus establishing a secondary or "capacity release" market;[12]
- promote the development and use of market centers to provide a central point for the pipeline companies to interconnect and for buyers and sellers to come together; and,
- curtail firm transportation services on a pro rata basis to all customers when unforeseen events, such as pipeline ruptures, cause disruptions in the pipeline system.

In addition, Order 636 eliminates the requirement that FERC review many pipeline companies' rates at least once every 3 years. In establishing the rates, FERC reviews the pipeline company's costs to determine whether they were prudently incurred. In addition, gas acquisition costs are reviewed for fraud or abuse. After the implementation of Order 636, FERC will not require this periodic rate review because the pipeline companies will no longer be able to automatically pass through the cost of gas supplies to their customers. According to FERC, however, it will continue to review the pipeline companies' transportation rates despite the elimination of the mandatory periodic review. Furthermore, the pipeline companies must request approval of changes to their rates when seeking to recover the cost of new facilities, increased operating costs, increased costs of capital or depreciation expenses, or costs resulting from the loss of customers. In addition, according to FERC, about 16 pipeline companies have agreed, in their plans to implement Order 636, to file for new rates

[10]FERC issued Order 636, Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 57 Fed. Reg. 13,267 (Apr. 16, 1992); Order No. 636-A, Order Denying Rehearing in Part, Granting Rehearing in Part, and Clarifying Order 636, 57 Fed. Reg. 36,128 (Aug. 12, 1992); and Order No. 636-B, Order Denying Rehearing and Clarifying Orders 636 and 636-A, 57 Fed. Reg. 57,911 (Dec. 8, 1992).

[11]FERC also allowed customers to continue to purchase "rebundled" services—a combined package of gas supplies, transportation, and storage services—from the pipeline companies.

[12]The creation of the capacity release market is designed to promote economic efficiency by allowing pipeline capacity to be purchased by those who value it most.

under section 4 of the NGA by no later than 1996. However, unless a schedule is stipulated in a future settlement agreement, these pipeline companies will file for new rates at their own discretion. Also, FERC—at its own discretion or upon the complaint of any state, municipality, state commission, or gas distribution company—may investigate any pipeline company's rates and lower them if it determines that they are too high.

Elements of Pipeline Companies' Rates

As explained in appendix I, FERC approves the rates that interstate pipeline companies charge for transportation and related services. Rates are important to customers because they determine not only how much a customer will pay but also who will pay the pipeline companies' costs. This appendix describes the basic components of a pipeline company's rates, the process of setting rates (known as rate design), how rate designs have changed over time, and some of the concerns related to the new rate design called for in Order 636.

Components of the Pipeline Companies' Rates

Pipeline companies recover their costs of providing services through two different charges: a commodity charge and a demand charge. The commodity charge is based on the volume of gas transported to the LDC or end-user.[1] Through the commodity charge, the pipeline company recovers at least the variable cost of transportation. Under some rate designs, it also recovers a portion of its fixed costs, such as depreciation and the return on investment in facilities.[2] The demand charge reflects a customer's right to reserve capacity on a pipeline company's system during periods of peak demand, such as cold winter days. Through the demand charge, a pipeline company recovers some or all of its fixed costs. Unlike the commodity charge, the demand charge is a single fee that is constant regardless of how much gas a customer actually purchases or transports.

Rate Design

The process by which a pipeline company's costs are applied to either the commodity or demand charge is known as cost classification. Since variable costs are always assigned to the commodity charge, a primary issue in rate design is how fixed costs are apportioned (classified) between the commodity and demand charges. Customers with firm service pay for their reservations of pipeline capacity through the demand charge.[3] Customers of interruptible service pay for the transportation of gas primarily through the commodity charge. As a result, the apportionment of

[1]When pipeline companies purchased gas on behalf of LDCs, the commodity charge included the costs of the gas supplies as well as transportation and other services. However, with open-access transportation and unbundling (see app. I), the cost of the gas and its transportation to LDCs have been separated. To reflect this change, Order 636 changes the names of the commodity and demand charges to the "usage fee" and the "reservation fee," respectively. In this report, we continue to use the terms "commodity charge" and "demand charge" to maintain consistency when discussing rate design before and after Order 636.

[2]Costs that change depending on the units of output, such as the costs of transporting gas, are known as "variable costs." Fixed costs are those that remain constant regardless of output.

[3]Technically, the demand charge rate is equal to the total fixed costs of the pipeline company divided by the sum of firm-service capacity reservations and the volumes projected to be transported by interruptible-service customers for the following year.

fixed costs between the two charges greatly determines who pays these costs.

In general, the greater the proportion of fixed costs included in the demand charge, the more of these costs customers with firm service (i.e., principally residential and small commercial customers) will pay. Adding more fixed costs to the demand charge also (1) rations pipeline capacity to customers who value it most and (2) permits the commodity charge to be based more closely on the price of gas supplies. On the other hand, the greater the proportion of fixed costs included in the commodity charge and paid per unit of gas delivered, the more of these costs customers with interruptible service (i.e., industrial customers) must pay. Including fixed costs in the commodity charge also provides an incentive for pipeline companies to increase the volumes of gas they transport. If a pipeline company is allowed to secure its return on equity or profit through a volumetric (i.e., commodity) charge, the more volume it transports, the greater its profits.

It is important to note that although customers with firm and interruptible service can generally be considered peak and off-peak customers, respectively, customers with interruptible service will still pay a portion of the pipeline companies' fixed costs under the rate design mandated by FERC in Order 636.[4] Because rates for interruptible service are calculated and billed to recover a portion of the demand charges, customers with interruptible service will still pay a portion of the pipeline companies' fixed costs even under the straight fixed variable (SFV) rate design.[5] The portion of a pipeline company's fixed costs paid by customers with firm service and customers with interruptible service is proportional to the total capacity reservations of firm-service customers and projections of the volumes that will be transported by interruptible-service customers, respectively.

Within the natural gas industry, it is generally accepted that there is no single way to properly classify fixed costs between the commodity and demand charges. FERC has acknowledged that balancing of policy goals

[4]The rate that FERC approves for interruptible service is determined by (1) the rate for firm service, (2) the amount of the total fixed costs that are assigned by FERC to interruptible service, and (3) the projected volume of total interruptible service on a pipeline company's system. However, the actual rate a customer with interruptible service pays can be lower because pipeline companies often discount the price of this service. It is important to note that there is not one uniform rate for interruptible service; these rates vary across pipeline companies.

[5]Technically, SFV and other methods of apportioning costs between the commodity and demand charges are forms of cost "classification" rather than rate designs. We use the latter term to reflect the terminology commonly used by the industry and FERC.

through rate design "is a matter of judgment and is not an exact science."[6] Some industry analysts maintain that all fixed costs should be borne by firm-service customers. These analysts reason that, since the capacity of the pipeline is built to serve firm-service customers at times of peak demand, those customers should pay for that capacity. Other industry analysts agree that firm-service customers should pay a larger proportion of the pipeline companies' fixed costs than customers with interruptible service because firm-service customers demand gas during periods of peak demand. However, these analysts contend that apportioning all fixed costs to firm-service customers is not optimal.[7] In their view, applying such a rate design would be particularly inappropriate on pipelines that do not operate at full capacity.

The History of Rate Design

Traditionally, FERC has adopted particular rate designs to further specific policy objectives. As FERC changes its objectives in response to new circumstances, it also adjusts its rate design.

The Evolution of FERC's Rate Designs

From 1952 until 1973, pipeline companies usually recovered their costs of service under the "Atlantic Seaboard" classification, which divided the allocation of fixed costs evenly between the commodity and demand charges.[8] However, in 1973 the Federal Power Commission—FERC's predecessor regulatory agency—responded to gas supply shortages by adopting the "United" classification, which raised the cost of gas by assigning 75 percent of fixed costs to the commodity charge.[9] In the early 1980s, the supply shortage abated, and the high price of gas supplies relative to other fuels became a more significant problem. In response, in 1983 FERC adopted the modified fixed variable (MFV) cost classification and rate design,[10] which removed all fixed costs, except for a pipeline company's return on equity and associated taxes, from the commodity charge.[11] Originally, under MFV, costs assigned to the demand charge were divided equally between a charge based on the amount of capacity a user reserved (known as the D-1 charge) and the actual annual usage (known

[6]FERC, Order 636, 57 Fed. Reg. 13,267 at 13,292 (1992).

[7]These analysts maintain that fixed costs should be divided between peak and off-peak customers on the basis of their relative demand elasticities (i.e., through a method known as "Ramsey pricing").

[8]Federal Power Commission, Atlantic Seaboard, 11 F.P.C. ¶ 43 (1952).

[9]United Gas Pipe Line, 50 F.P.C. ¶ 1348 (1973); reh. denied, 51 F.P.C. ¶ 1,014 (1974).

[10]FERC adopted MFV in Natural Gas Pipeline of America, 25 F.E.R.C. ¶ 61,176 (1983).

[11]According to the Interstate Natural Gas Association of America, the return on equity and associated taxes represent about 15-20 percent of a pipeline company's fixed costs.

as the D-2 charge). However, in its 1989 policy statement on rate design, FERC suggested that the D-2 charge be eliminated. FERC reasoned that the elimination of the D-2 charge would place more fixed costs into the D-1 charge, raising the price of reserving pipeline capacity. In turn, the higher price would better ration capacity to customers who value it most. FERC also maintained that, by lowering the costs charged to customers who purchase large volumes annually (thus potentially raising their demand for gas), pipeline companies would increase the volume of gas they transport. Several pipeline companies responded by eliminating this charge.

Straight Fixed Variable Rate Design

Order 636 represents the latest change in FERC's policy goals for rate design. As expressed in the order, FERC is currently seeking to promote competition among sellers of natural gas. As a result, FERC mandated the use of the SFV cost classification and rate design, which removes all fixed costs from the commodity charge.[12] FERC contends that SFV rate design increases efficiency because the commodity charge reflects only the price of gas. FERC found that MFV rate design distorts the gas purchaser's decision by subjecting the wellhead or field prices of gas merchants to different pipeline equity ratios. For example, under MFV (or any other rate design that assigns a portion of fixed costs to the commodity charge), the producers that are connected to a more fully depreciated pipeline (i.e., one with lower fixed costs) had a competitive advantage over the producers that are connected to a pipeline with higher fixed costs. Also, according to FERC, because SFV rate design places all fixed costs in (and thereby raises) the demand charge, it will better ration pipeline capacity to those who value it most. In FERC's view, SFV corrects a significant problem with previous rate designs, such as MFV, because those rate designs raised the variable cost of transporting gas supplies, impeding off-peak consumption and the optimal use of the national pipeline grid. Since SFV lowers the variable cost of transporting natural gas (i.e., the commodity charge), it could increase the volume of gas transported. Increased volume, in turn, would lower the unit cost of transporting gas and reduce the demand charge that individual pipeline customers pay.

Proponents of SFV maintain that by removing fixed costs from the commodity charge, SFV will also make domestic suppliers more competitive with Canadian suppliers, who for years have shipped gas to the United States under an SFV rate design. Independent producers and others have argued that the difference in U.S. and Canadian rate designs

[12]As noted above, because rates for interruptible service are based, in part, on the demand charge paid by firm-service customers, interruptible-service customers will still pay a portion of a pipeline company's fixed costs through the demand charge, even under SFV.

has made the commodity charge for transporting Canadian gas supplies lower.

However, some industry analysts have voiced strong opposition to SFV, for the following reasons:

- SFV could result in significant cost-shifts, moving even more of the pipeline companies' fixed costs from customers with interruptible service to customers with firm service. (See app. III.)
- SFV increases the percentage of pipeline companies' fixed costs that are recovered automatically through the demand charge. At the same time, Order 636 eliminates the requirement that FERC review these costs once every 3 years for many pipeline companies. Thus, as a pipeline company's rate base depreciates, the company could keep any excess revenues it collects before its rates are reviewed again by FERC.
- SFV will lower pipeline companies' incentive to maximize the amount of gas they transport because it will increase the percentage of fixed costs that the companies recover automatically.
- FERC has not lowered the return on equity that the pipeline companies receive commensurate with the companies' lower risk under SFV.
- SFV may create inefficiencies when applied to those pipeline companies that do not operate at peak or full capacity. If capacity is consistently underbooked, the price for reserving capacity may be too high. Raising the cost of reserving capacity by imposing SFV in this situation would exacerbate the problem and lead to a less efficient allocation of capacity on the pipeline.[13]
- SFV may also create other inefficiencies. As FERC considers incentive ratemaking or other similar initiatives to promote market forces in the industry, the pipeline companies could use their guaranteed profits for transportation service under SFV to subsidize—and thus gain a competitive advantage in—the other nonregulated services they sell, such as marketing services.[14]
- In the opinion of some analysts, FERC did not perform a rigorous quantitative analysis in formulating Order 636 to substantiate its contention that end-users will benefit from this change in rate design. For

[13]FERC, in a 1989 policy statement, said that the imposition of SFV on underbooked pipelines would increase inefficiency. See FERC, Policy Statement Providing Guidance With Respect to the Designing of Rates, 47 ¶ F.E.R.C. 61,295, p. 11.

[14]An analogous argument was made in the telecommunications industry for limiting the activities of local operating companies. In 1983, the U.S. District Court for the District of Columbia approved a consent decree in United States v. American Telephone and Telegraph, 552 F. Supp. 131, affd. sub nom. Maryland v. United States, 460 U.S. 1001 (1983) that local operating companies would have to show that there is no substantial possibility that they could use their monopoly power to impede competition (i.e., cross-subsidize unregulated businesses).

example, FERC did not consider the potential effect of SFV rate design on the wellhead price of gas. One industry official has estimated that SFV will increase the wellhead price of gas to LDCs by about $1.4 billion per year because producers will raise their selling price to equal the prices of alternative fuels.

In response to these criticisms, FERC contends that it has taken steps to ensure that LDCs will generally not experience more than a 10-percent increase in their transportation rates as a result of the change to SFV. FERC maintains that it will continue to review the prudence of each pipeline company's rate base and lower the company's return on equity when appropriate. Also, FERC contends that a pipeline company still risks not recovering all of its fixed costs, particularly if (1) its actual expenses are higher than those projected and used by FERC in setting the company's rates and (2) a portion of the company's fixed costs are recovered through the sale of interruptible transportation and the company's sales of interruptible service are less than the level used in setting the rates. As discussed in appendix III, we estimated that even after the imposition of SFV, customers with interruptible service will still pay about 24 percent of the pipeline industry's total fixed costs.

FERC has generally rejected the petitions of pipeline companies or their customers, under Order 636, to use anything but SFV rate design if the pipeline companies impose a reservation charge on customers with firm service. FERC has only allowed alternative rate designs in a few cases in which it is impossible to use SFV because the pipeline companies do not have firm-service customers who pay reservation charges. However, FERC recently reversed itself on an earlier decision and will allow a pipeline company to use MFV rates for an electricity generating facility.[15] On the basis of data supplied by the owners of the electricity generator, FERC concluded that SFV rate design would cause the owners to lose revenues and operate at a loss. Moreover, FERC determined that MFV rates were appropriate for this facility in order to meet the congressional goals of reducing oil imports and environmentally harmful emissions produced by electricity generators. Another pipeline company has recently requested that FERC allow it to use MFV rates for an electricity generating facility in order to meet these congressional goals.

[15]Order on Compliance Filing and Granting Rehearing in Part and Denying Rehearing in Part, 63 F.E.R.C. ¶ 61,285 (1993).

Subsidization Among Customer Classes

Some analysts maintain that the cost-shifts resulting from the proposed change in rate design are warranted because they reduce a supposed subsidy provided to firm-service customers by MFV rate design. In their view, MFV subsidized customers with firm (peak) service, especially those served by small LDCs, by imposing too many fixed costs on customers with interruptible (off-peak) service. A representative of municipal gas distributors holds the opposite view: In his opinion, by moving all fixed costs to the demand charge, SFV will subsidize interruptible-service customers.

Determining the presence and amount of cross-subsidization in the natural gas industry is extremely difficult because, as explained above, within the natural gas industry, it is generally accepted that there is no single way to properly classify fixed costs between the commodity and demand charges. Without a generally accepted allocation of fixed costs between peak and off-peak customers to serve as a yardstick, we cannot definitively determine whether MFV or SFV establishes cross-subsidies.

In addition, estimating subsidies among customers is difficult because it is often hard to ascertain the true costs of individual pipeline services that were previously sold together. Many of the costs incurred by pipeline companies are "joint" or common costs, such as salaries or the costs of certain facilities, that cannot be directly attributed to a particular service.

GAO's Cost-Shift Estimates

One of the primary objectives of our review was to estimate the nationwide shift in who pays the pipeline companies' fixed costs, without measures to mitigate these shifts, as a result of the switch from MFV to SFV rate design mandated in Order 636. Working with two industry consultants, we developed several estimates to construct a range of potential cost-shifts, depending upon the assumptions used in the analysis. In addition, we performed case-study analyses on five judgmentally selected pipeline companies to determine the cost-shifts that might be expected among LDCs and their residential, commercial, industrial, and electric utility end-users.

This appendix presents the results of our analyses. First, it describes our nationwide cost-shift analyses, discussing (1) the assumptions underlying each cost-shift estimate and (2) GAO's best estimate (i.e., the estimate derived from the assumptions we believe best reflect the current and future industry conditions). It also analyzes the cost-shift estimates developed and reported by FERC in Order 636-A. Second, this appendix discusses our case-study analyses, focusing on (1) our major assumptions, (2) the possible cost-shifts among residential, commercial, and industrial end-users resulting from the change in rate design, and (3) the possible cost-shifts among end-users resulting from the change in rate design plus the creation of the capacity release market. Finally, this appendix reviews the major factors, such as the mitigation measures prescribed by FERC, that may affect the actual shifts in costs.

The Role of Assumptions in Estimating the Nationwide Cost-Shift

The final cost-shifts resulting from the switch from MFV to SFV rate design are not easily measured. Any cost-shift estimate will be significantly affected by several assumptions. We identified three major assumptions that have a particular impact on our cost-shift estimates:

(1)The initial demand charge structure used. As stated in appendix II, MFV rate design has employed two types of demand charges. Initially, fixed costs assigned to the demand charge were divided equally between a D-1 charge, based on the amount of pipeline capacity reserved, and a D-2 charge, based on the volume of gas actually purchased by a customer. However, in a 1989 policy statement, FERC suggested eliminating the D-2 charge to, among other things, better ration pipeline capacity during periods of peak demand.[1] In response to the policy statement, several pipeline companies eliminated their D-2 charges.

[1]Policy Statement Providing Guidance With Respect to the Designing of Rates, 47 F.E.R.C. ¶ 61,295 (1989).

The goal of the analysis determines which type of MFV demand charge should be used in estimating the shift in costs resulting from the change in rate design. If the goal of the analysis is to measure the total cost-shift generated by FERC's initiatives since 1989 designed to promote open-access transportation and greater competition, then the analysis should calculate MFV demand costs using both the D-1 and D-2 charges. However, if the goal is to measure the marginal cost-shifts associated with the change in rate design, the appropriate analysis should include a D-1 charge only (also known as a one-part demand charge).

(2)The benefit of interruptible service. LDCs purchase some interruptible service for end-users. The final shift in costs among end-users depends upon how much interruptible transportation has been purchased by LDCs on behalf of industrial and electric utility end-users or residential and small commercial end-users.[2] When LDCs have purchased interruptible service on behalf of residential end-users, these end-users have been paying the fixed costs associated with interruptible service under MFV. Thus, while moving the fixed costs from the commodity to the demand charge under SFV will shift some fixed costs from customers with interruptible service to customers with firm service, residential end-users would pay some of the fixed costs associated with interruptible service under both MFV and SFV. As a result, the change in rate design would not shift these fixed costs to residential end-users. On the other hand, when LDCs have purchased interruptible service for industrial businesses and electric utilities, the change in rate design will shift costs from these end-users to residential end-users.

(3)Discounting interruptible service. Since 1985, in order to promote competition among pipeline companies, FERC has allowed the pipeline companies to discount interruptible service. Many analysts expect that the creation of a secondary market in released pipeline capacity under Order 636 will significantly increase the amounts of these discounts. These analysts reason that because the new secondary market in released capacity will give shippers more choices in firm service, the rates for interruptible service will have to be further discounted to remain competitive. To the extent that the pipeline companies have to discount the rates they charge for interruptible service, they risk underrecovering the fixed costs assigned to that service, at least until the pipeline companies can have their rates adjusted in the next rate case (i.e., when they next apply to FERC for new rates).

[2]GAO was unable to obtain complete information on the percentage of firm and interruptible transportation services purchased from pipeline companies by the LDCs in our case-studies for each end-user class they serve.

Nationwide Cost-Shift Estimates

GAO estimates that FERC's change in rate design will shift about $1.2 billion annually in the pipeline companies' fixed costs from interruptible-service to firm-service customers. In contrast, FERC estimated this cost-shift to be $800 million per year. The difference in the two estimates is a result of using different assumptions about the natural gas industry. FERC also made certain adjustments in its cost-shift analyses that we believe are inappropriate.

GAO's Best Estimate

Using the assumptions that we believe are most appropriate, GAO estimates that the change from an MFV to an SFV rate design, unless mitigation measures are employed, may shift about $1.2 billion in fixed costs annually from interruptible-service to firm-service customers. This would increase the share of the pipeline industry's total fixed costs (about $11.4 billion annually) paid by customers with firm service from about 65 percent to 76 percent.[3] Customers with interruptible service would pay about 24 percent of the pipeline companies' fixed costs. Our estimate is based on the following assumptions:

- Use of a D-1 charge only. We were asked to assess the potential cost-shifts associated with Order 636. Thus, we believe an MFV rate design that includes only a D-1 charge is the most appropriate starting point.
- Benefit of interruptible service. We assume that LDCs purchased all interruptible service on behalf of their industrial and electric utility end-users. This is a simplification. However, on the basis of our conversations with LDC officials and other industry experts, we believe that the majority of interruptible service is purchased on behalf of these end-users, since many of these end-users have the ability to switch fuels. As a result, our assumption should be closer to actual practice than FERC's opposite assumption—that LDCs purchase all interruptible service on behalf of residential and commercial end-users.
- Discounting of interruptible service. We believe that a realistic cost-shift analysis must consider the effect of discounts on interruptible service both before and after the implementation of Order 636. Our analysis assumes that the price currently paid for interruptible service (before Order 636) is 10 percent less than the FERC-approved "just and reasonable" rate for such service. After Order 636 is implemented, we assume interruptible service

[3]Our estimate of $11.4 billion in total fixed costs is based on 1990 industry statistics. This figure includes costs associated with the pipeline companies' construction work in progress. Although FERC, as a matter of policy, does not include construction work in progress in the rate base, it does allow the pipeline companies to capitalize an allowance for funds used during construction. Moreover, FERC develops a test period rate base that includes all facilities that will be in service within 9 months of the base period.

will be sold at 50 percent of FERC's just and reasonable rate for such service. Although these estimates of discounting may not be precise, we believe they are highly conservative.[4]

As explained in greater detail later in this appendix, the actual cost-shift could be higher or lower than our estimate, depending on a number of factors, such as the amount of interruptible service purchased after Order 636 is implemented, the price of capacity reservations sold in the secondary market, and the way FERC calculates the rates for interruptible service and firm service.[5]

FERC's Cost-Shift Estimates

In Order 636-A, FERC initially estimated that its prescribed change in rate design will shift $1.3 billion annually from customers with interruptible service (primarily industrial businesses and electric utilities) to customers with firm service (primarily residential and small commercial end-users). FERC then made an adjustment that lowered the shift to $800 million per year. We believe that (1) FERC's analyses do not use the most appropriate demand-charge structure and (2) FERC's adjustment to its initial estimate was predicated on a faulty assumption.

All of FERC's cost-shift analyses, including the initial $1.3 billion per year estimate, started with an MFV rate design that includes a two-part (D-1 and D-2) demand charge. Since FERC's objective was to estimate the incremental cost-shift resulting from Order 636, we believe a better starting point would reflect the current MFV demand charge (i.e., a D-1 charge only) adopted by many major pipeline companies.[6] The use of the two-part demand charge overstates the cost-shift, because the elimination of the D-2 charge itself shifts costs from interruptible-service customers to firm-service customers.[7]

[4]In Natural Gas 1992: Issues and Trends, DOE/EIA-0560(92) the Energy Information Administration notes at p. 66 that the creation of the secondary market in released pipeline capacity may force the price of interruptible service down to the variable cost of transporting gas.

[5]For example, the load factor or capacity utilization of the pipeline (see explanation in the text below) assumed by FERC can have a significant effect on the rate for interruptible service and, in turn, on the amount of fixed costs paid by particular end-users.

[6]To corroborate our method of calculating that cost-shift, we performed an analysis using FERC's initial assumptions. Our consultants calculated cost-shifts of $1.4 billion and $1.5 billion. The slight differences with FERC's initial estimate resulted from our belief that certain costs, such as construction work in progress, should be included in the total estimate of the industry's fixed costs.

[7]For example, when we eliminated the D-2 charge from our replication of FERC's initial analysis, our estimate of the cost-shift dropped from about $1.4 billion to $530 million.

FERC's initial estimate of the cost-shift assumed that all interruptible service purchased by LDCs is on behalf of end-users with fuel-switching capability. FERC then modified this assumption, which, in turn, lowered its initial cost-shift estimate to $800 million per year. FERC assumed that all interruptible service purchased by LDCs is on behalf of firm-service (i.e., residential and small commercial) customers. This assumption lowered the estimated cost-shift among end-users because, under this scenario, firm-service customers would have been paying the fixed costs associated with interruptible service under MFV. Thus, these fixed costs would not be "shifted" to them under SFV—residential and small commercial end-users would be paying the costs under either rate design.

We believe this assumption is incorrect. Based on our conversations with industry experts, we believe that LDCs purchase most interruptible service to serve end-users with interruptible service, such as industrial end-users. Thus, shifting the costs assigned to interruptible service under MFV to firm service under SFV would constitute a shift in the responsibility for paying fixed costs from industrial and electric utility (i.e., interruptible-service) end-users to residential and small commercial (i.e., firm-service) end-users, since industrial businesses generally do not purchase firm service. In fact, in our analysis we assume that all interruptible service purchased by LDCs is on behalf of industrial (i.e., interruptible-service) businesses. Our assumption is also a simplification. However, lacking reliable data on who receives the majority of interruptible service, we believe our assumption better reflects the LDCs' actual purchasing patterns.

In addition, we believe FERC's $800 million estimate understates the cost-shift because it does not consider the effect of increased discounts on interruptible service after the implementation of Order 636. (As noted earlier, interruptible service is often discounted to make gas supplies competitive with alternative fuels. A pipeline company will also discount its interruptible service to make it competitive with the transportation service provided by other pipeline companies.) If discounting of interruptible service increases under Order 636, a portion of the remaining fixed costs previously assigned to customers with interruptible service may be shifted to customers with firm service. We believe a realistic assessment of impending cost-shifts must include the probable increase in discounting after Order 636 is implemented.

Finally, FERC made a second adjustment to estimate the costs that would be shifted specifically to residential end-users. To do this, FERC assumed that the $800 million cost-shift per year would be passed on to residential end-users in proportion to their percentage of the total gas consumed (26 percent). Thus, according to FERC, the final cost-shift to residential end-users would be $210 million ($800 million x 0.26), or about $4.20 annually for the average customer.

We believe this adjustment is also inappropriate. FERC used an incorrect figure to reduce the annual $800 million cost-shift. Since the $800 million figure represented the annual shift in cost to customers with firm service, the share of that estimate paid by residential end-users equals their proportion only of firm service, not their proportion of the total gas consumed. FERC's approach underestimates the cost-shift to residential end-users. We could not quantify the underestimate because the data on the amount of firm service purchased by each type of end-user is incomplete.

Table III.1 provides a summary of the cost-shift estimates and their underlying assumptions.

Table III.1: Estimates of the Nationwide Shift in Pipeline Companies' Fixed Costs

Dollars in billions

		Assumptions		
Cost-shift estimate[a]	**Final cost-shift**	**D-2 charge included**	**Interruptible service discounted**	**Beneficiary of interruptible service**
GAO-1	$1.2	No	Yes	Industrial
FERC-1	$0.8	Yes	No	Residential
FERC-2	$1.3	Yes	No	Industrial
GAO-2	$1.4 to $1.5	Yes	No	Industrial
GAO-3	$0.53	No	No	Industrial
FERC-3	$0.21	Yes	No	Residential

[a]GAO-1 is our estimate of the nationwide cost-shift from customers with interruptible service to customers with firm-service based on what we believe are the most appropriate assumptions. FERC-1 is FERC's cost-shift estimate after adjusting for the interruptible service purchased by LDCs. FERC-2 represents FERC's initial estimate without any adjustments. GAO-2 was estimated using the same assumptions shown above as used by FERC in FERC-2. GAO-3 assumes that interruptible service is not discounted after the implementation of Order 636. FERC-3 estimates the cost-shift specifically to residential end-users.

GAO's Case-Study Analysis

The purpose of our case-study analysis was to examine how residential customers and other end-users might be affected by the switch from MFV to SFV rate design and other changes resulting from Order 636. We also wanted to determine whether and to what degree a particular class of end-users may fare differently depending upon the mix of end-users—also known as the "load factor"—served by the LDC.[8] For this analysis, we chose five interstate pipeline companies and either (1) used each pipeline company's estimates of the anticipated cost-shifts to each LDC it serves or, (2) when these data were unavailable, calculated the cost-shift for each LDC ourselves.[9] Then, using several scenarios about how costs are apportioned by LDCs to their end-users, we calculated the possible cost-shifts among residential, commercial, industrial, and electric utility end-users. (For information on how we calculated the cost-shift under each allocation scenario, see app. VII.) We express cost-shifts as changes in the cost of gas delivery (i.e., the final gas bill) to an end-user, holding constant the price of gas supplies, the LDC's markup, and each end-user's total consumption. Each estimate represents the change to an end-user's final gas bill that we estimated for a single LDC only.

Types of Cost-Shifts

In our analysis, we examined two types of cost-shifts. For three pipeline companies—United Gas Pipeline Company, Southern Natural Gas Company, and Texas Gas Transmission Corporation—we estimated the possible cost-shifts among end-users resulting from the change in rate design alone. For the other two pipeline companies—Transcontinental Gas Pipeline Corporation and Tennessee Gas Pipeline Company—we estimated the possible cost-shifts among end-users resulting from both the change in rate design and the creation of the capacity release market.

The creation of a capacity release market will affect the ultimate cost-shifts. As described later in this appendix, the capacity release market could mitigate any cost-shifts, as LDCs may release and resell unneeded capacity to reduce cost burdens imposed by the change in rate design. However, LDCs may have to offer their unneeded capacity at deep discounts (lower than the previous price of interruptible service) at times of the year when demand is low. As a result, they may not receive enough revenue to cover the price they paid to reserve pipeline capacity. The less

[8]Load factor is the percentage of an LDC's capacity reservations that it actually uses. LDCs with a high load factor generally utilize their capacity to transport gas more evenly throughout the year. LDCs with a low load factor generally utilize their capacity to transport gas primarily during the winter heating season. The load factor of an LDC is basically determined by the load factors of the end-users it serves. LDCs that serve a greater number of industrial end-users have higher load factors than LDCs that serve primarily residential end-users.

[9]The pipeline companies reported their anticipated cost-shifts in their filings before FERC explaining how they will comply with Order 636. FERC asked some pipeline companies to resubmit these data. Reliable cost-shift data for three of the five pipeline companies we studied were unavailable at the time of our analysis because the estimates were contested by the pipeline companies' customers or by FERC.

an LDC receives for its released capacity, the larger the ultimate cost-shift resulting from the change in rate design will be.[10]

Cost Apportionment Scenarios

The prices for natural gas supplies and transportation (and thus the fixed costs of the pipeline companies) that most end-users pay are ultimately determined by the state or local authorities that approve the rates LDCs charge for delivering the gas. Public utility commissions or municipal distributors can distribute these costs in a variety of ways.

However, according to several industry experts, how states and localities distribute an LDC's responsibility for the pipeline companies' fixed costs is not well understood and cannot be easily generalized. To circumvent this problem, in our analysis we allocated to end-users the costs that the pipeline companies charge to LDCs under three different scenarios:

- <u>The pro rata method</u>. Under this method, we assumed that an LDC would allocate the change in its fixed-cost responsibility to its end-users in proportion to the end-users' consumption of a pipeline company's transportation services. Thus, if residential end-users received 60 percent of the gas purchased by their LDC, these end-users would pay 60 percent of the LDC's fixed-cost responsibility.
- <u>The all-to-residential-end-users method</u>. Under this scenario, residential end-users pay any increased costs to the LDC resulting from the change in rate design. We assumed that if a portion of the fixed costs assigned to an LDC increased, the LDC would assign those costs to the customer class that has the least ability to switch to other fuels or to by-pass the LDC to get direct service from a pipeline company. Under this scenario, the revenues paid by residential end-users of an LDC would be reduced if the LDC's costs decline as a result of the change in rate design.
- <u>The costs-allocated-as-incurred method</u>. Under this scenario, we assumed that the fixed costs assigned to the LDC are passed to end-users as incurred, according to the amount of capacity that LDCs purchased on their behalf. For example, if all the fixed costs charged to an LDC were the result of the LDC's firm-service requirements, and residential end-users demanded 90 percent of that firm service, residential end-users would pay 90 percent

[10]In our analysis, we assume that interruptible transportation service has been sold at a 10-percent discount (from the rate for interruptible service approved by FERC) on an average annual basis prior to Order 636 and that firm transportation capacity released in the secondary market will be sold at a 50-percent discount from that rate after the order is implemented.

of the fixed costs charged to the LDC.[11] For this scenario, we assumed that residential end-users consume gas at a load factor of 20 percent.[12]

Based on discussions with our two industry consultants, we believe the all-to-residential and costs-allocated-as-incurred scenarios best describe how most LDCs allocate their costs.

GAO's Analysis of Shifts in Costs Among End-Users Resulting From the Change in Rate Design Alone

Our analysis showed that, without mitigation measures, the potential cost-shift resulting from the change in rate design alone may be larger for residential end-users whose LDC serves a high concentration of residential and small commercial end-users (i.e., LDCs that have relatively low load factors).[13] Other things being equal, the more an LDC's end-users concentrate their gas use in a single period of the year, the greater their prospective increases in the LDC's total costs of gas delivery resulting from the change in rate design.[14] In addition, residential end-users may generally face larger increases in costs than industrial and electric utility end-users.[15]

Residential End-Users Are Not Affected Equally

According to our estimates of the cost-shifts to the end-users of 51 LDCs served by the three pipeline companies in this analysis, residential end-users served by LDCs with lower load factors (i.e., LDCs with a higher concentration of residential and small commercial end-users) may

[11]Residential end-users can experience a larger cost-shift under the costs-allocated-as-incurred scenario than under the all-to-residential-end-user scenario. Under the former scenario, cost responsibilities can be shifted among end-user classes served by a single LDC. Significant shifts can occur among customers even though the net shift to the LDC may be zero. Under the all-to-residential-end-users scenario, the shift to residential end-users is limited to the change in costs experienced by the LDC.

[12]For this method, we allocated the pipeline companies' fixed costs by assuming a 20-percent load factor for residential end-users. We made this assumption on the advice of our consultant most familiar with LDCs. According to this consultant, for most LDCs a 20-percent load factor best depicts the consumption patterns (relative to capacity reservations) of the residential end-users.

[13]We obtained this result under the all-to-residential-end-users cost allocation scenario.

[14]In Natural Gas 1992: Issues and Trends, DOE/EIA-0560 (92), the Energy Information Administration (EIA) reported a similar result when it estimated the potential effects of the change in rate design. However, it is important to note that EIA estimated the change in transportation and storage costs to LDCs rather than the total cost of gas delivered to end-users. To compare our results with EIA's, we estimated the cost-shift based on transportation and storage costs only to LDCs served by one of the pipeline companies in our case-study. Although our cost-shift estimates for the LDCs served by this pipeline company are somewhat less on a percentage basis than the cost-shifts reported by EIA, we both found that LDCs with lower load factors will face greater increases than LDCs with higher load factors.

[15]An LDC whose demand for gas is concentrated in the cold winter months uses relatively less of its pipeline capacity reservations year-round. As a result, the LDC's load factor, which equals the ratio of the LDC's actual gas purchases to the LDC's capacity reservations is lower.

experience greater increases in the total cost of gas delivery as a result of the change in rate design than residential end-users served by LDCs with higher load factors (i.e., LDCs serving a higher concentration of industrial end-users and electric utilities).[16] For example, if all cost changes to LDCs were passed directly to residential end-users only, we estimated that the delivered price of gas to residential end-users served by high-load-factor LDCs would change in a range from about a 3-percent decrease to a 3-percent increase.[17] In contrast, residential end-users served by LDCs with relatively low load factors would experience, without mitigation measures, an increase in their cost of gas delivery ranging from about 1 to 9 percent, or about $4 to $52 per residential customer annually (see table III.2).[18] Residential end-users served by low-load-factor LDCs face greater cost increases because the fixed costs allocated to their LDCs increase.[19] As shown in figure III.1, we estimated that, under this scenario, residential end-users served by 12 of the 17 LDCs with low load factors would experience an increase in costs of 3 percent or greater. In contrast, residential end-users served by 10 of the 16 LDCs with high load factors would experience decreases in their cost of gas delivery of up to 3 percent.

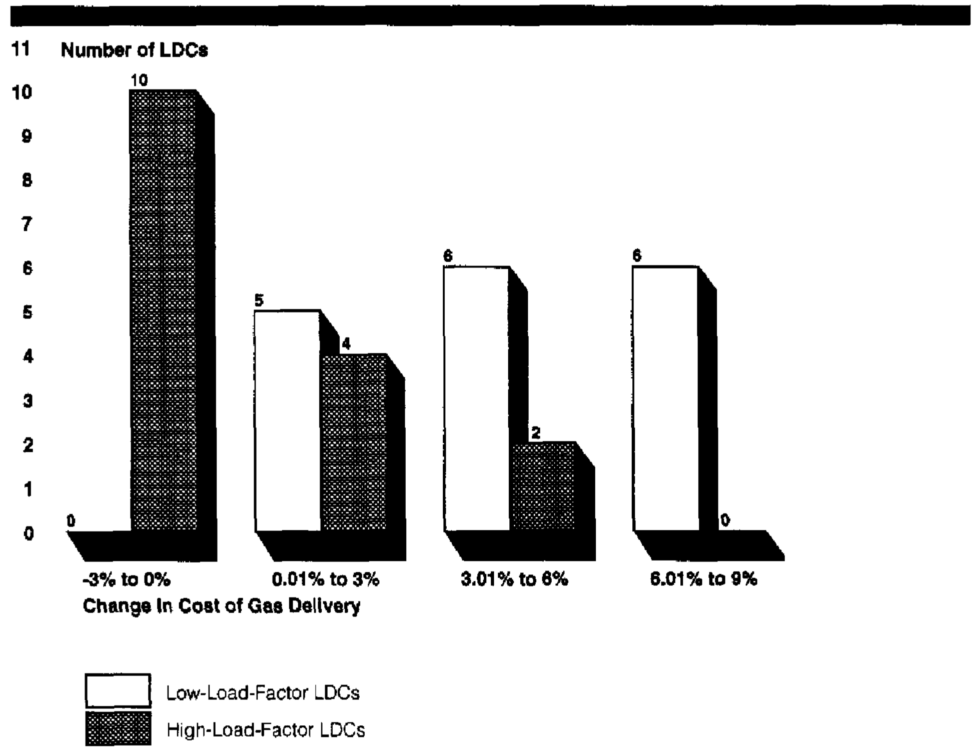
[16]The total cost of gas delivery includes the cost of the gas supplies, the transportation of the gas on the interstate pipeline to the LDC, storage, and the final delivery by the LDC to the end-user.

[17]For the purposes of this analysis, we sorted and divided the LDCs by load factor into three groups: high, medium, and low. Each group had roughly the same number of LDCs.

[18]For each cost apportionment scenario described earlier, we calculated the annual dollar change in costs per residential end-user using three steps. First, we estimated the total change in an LDC's costs that would be assigned to residential end-users. Second, we divided this change by the total volume of gas consumed by the LDC's residential end-users to derive the change in costs to these end-users per unit of gas consumed. Third, for each LDC, we multiplied the change in costs per unit of consumption by the residential end-user's average annual consumption of gas. This gave us the annual change in costs per residential end-user for the LDC. For more details on our methodology, see app. VII.

[19]We calculated the percentage change in costs by calculating the difference in an LDC's cost responsibility under SFV and MFV rate designs, then dividing this difference by the LDC's cost responsibility under MFV. For details, see app. VII.

Figure III.1: Estimated Change in the Cost to Residential End-Users as a Result of the Change in Rate Design Alone



Source: GAO's analysis of the pipeline companies' rate and compliance filings and industry data.

As shown in table III.2, we estimated that residential end-users served by LDCs with lower load factors will also experience greater increases in their cost of gas delivery if the pipeline companies' costs are allocated according to the end-users' consumption (i.e., the pro rata method). In contrast, under this allocation method, residential end-users served by LDCs with high load factors may experience little or no change in their cost of gas delivery.

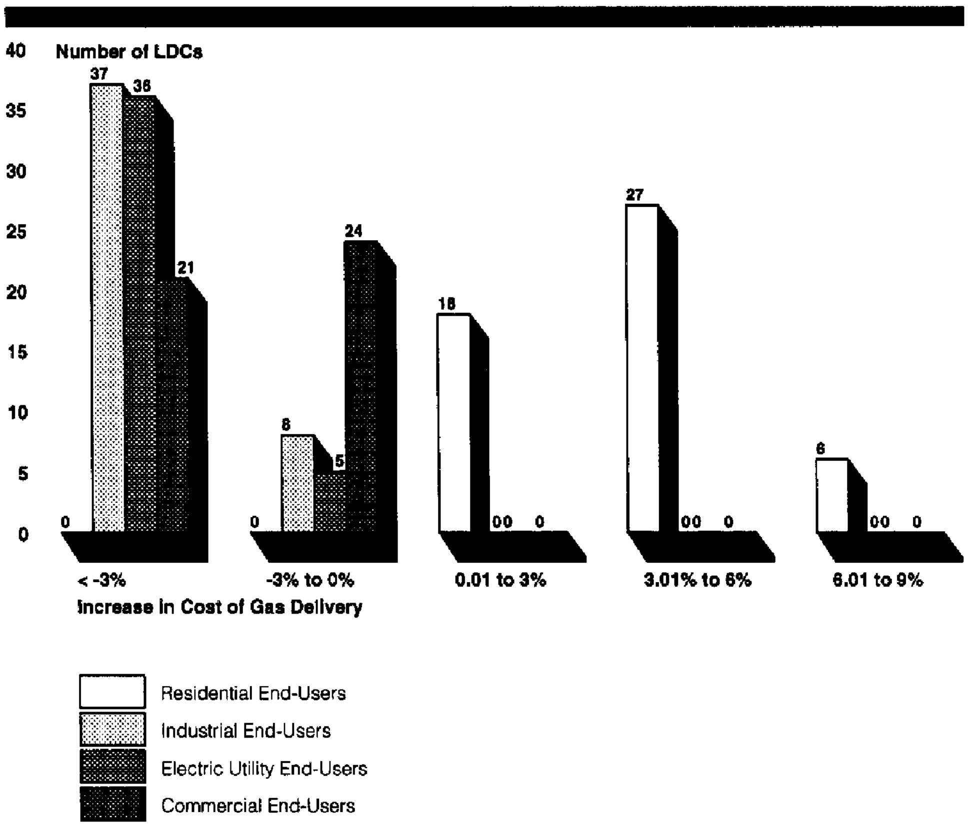
Table III.2: Percent Change in the Cost to Residential End-Users

	LDC allocation scenario		
Load Factor	Pro rata	All-to-residential-end-users	Costs-allocated-as-incurred
High	-1.0 — 0.7%	-3.3 — 3.1%	0.9 — 5.8%
Medium	-0.2 — 2.5	-0.4 — 5.4	2.4 — 7.4
Low	1.5 — 4.0	1.1 — 8.6	1.8 — 8.5

Residential End-Users May Face Greater Cost Increases Than Other End-Users

Whether residential end-users experience greater increases in costs than other end-users depends on how LDCs allocate costs. For example, as shown in figure III.2, if LDCs allocate their changes in costs among end-users as they are incurred, the residential end-users served by 27 of the 51 LDCs would experience increases of between 3 and 6 percent (about $12 to $36 annually) in their cost of gas delivery. The residential end-users served by 6 LDCs would experience, without mitigation measures, an increase in their cost of gas delivery between 6 and 9 percent (about $30 to $53 annually). In contrast, under the same cost allocation assumption, the commercial, industrial, and electric utility end-users served by every LDC in all our case studies except one will experience either no change or a decrease in their cost of gas delivery of as much as 7.5 percent.

Figure III.2: Estimated Change in the Cost to Each End-User Class Under the Costs-Allocated-As-Incurred Method



As shown in tables III.2 and III.3, if LDCs decide to allocate their changes on a pro rata basis, the potential cost increases faced by residential end-users are about the same as those faced by other end-users. For example, we estimated that residential, commercial, industrial, and electric utility end-users would experience little or no increase in costs from the change in rate design if they are served by LDCs with high load factors. We estimated that all classes of end-users would experience a modest increase—up to about 4 percent—if they are served by LDCs with medium load factors and increases of about 1 to 8 percent if they are served by LDCs with low load factors.

Table III.3: Percent Change In the Cost to Nonresidential End-Users

		Cost allocation method used by LDCs	
Customer	Load factor	Pro rata	Costs-allocated -as-incurred
Commercial	High	-1.3 — 0.9%	-4.1 — -1.1%
	Medium	-0.2 — 2.9	-4.1 — -0.3
	Low	1.7 — 4.5	-4.2 — 0
Industrial	High	-2.4 — 1.5	-5.6 — -1.9
	Medium	-0.2 — 3.8	-5.6 — -0.5
	Low	2.9 — 6.6	-6.4 — 0
Electric utility	High	-2.7 — 1.9	-6.5 — 0
	Medium	-3.1 — 4.1	-5.8 — 0
	Low	3.5 — 7.7	-7.5 — 0

Shifts in Costs Among End-Users as a Result of the Change in Rate Design and the Creation of the Capacity Release Market

In this analysis of two pipeline companies, we also found that residential end-users served by LDCs with a low load factor may experience a larger increase in their total cost of gas delivery than other residential end-users.[20] In addition, the cost-shifts experienced by residential end-users will differ depending on how each LDC distributes changes in costs to its end-users. Also, if LDCs directly pass on changes in costs as incurred on behalf of end-users, the change in rate design and the creation of the capacity release market will transfer costs from industrial, commercial, and electric utility end-users to residential end-users.

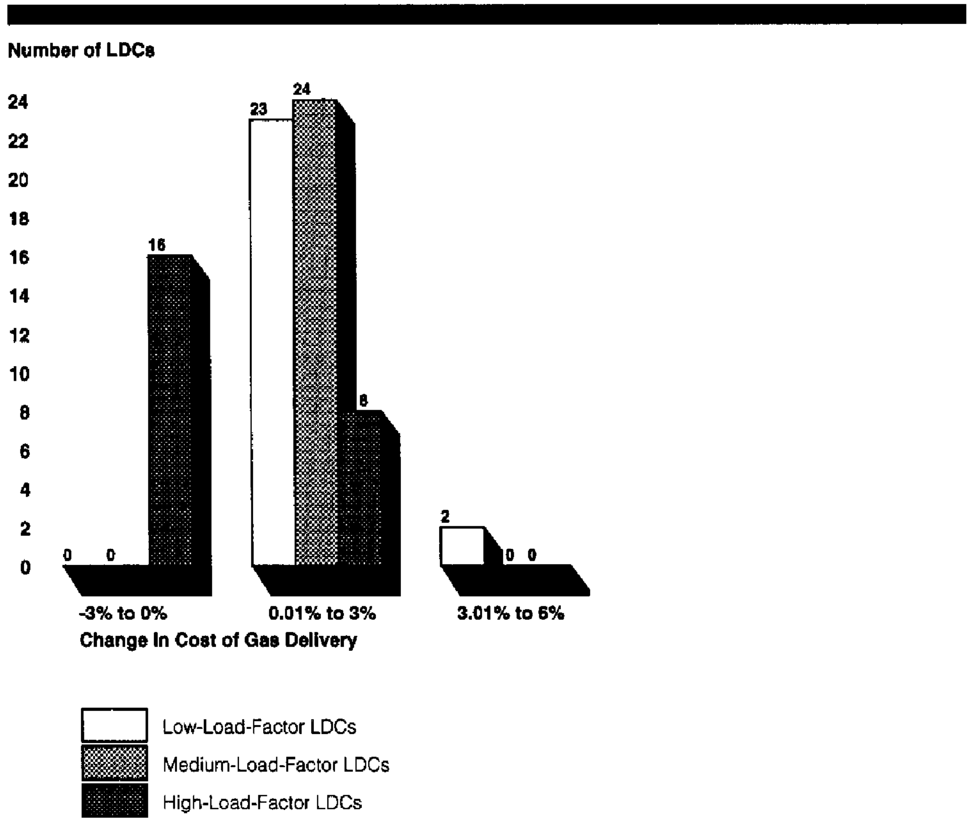
[20]Because the two pipeline companies in this analysis are different from the three pipeline companies we used to estimate the cost-shifts resulting from the change in rate design alone, the magnitude of the cost-shifts in the two analyses cannot be strictly compared. In our analysis of the change in rate design alone, the three pipeline companies we chose serve primarily the South and Midwest. These pipeline companies have different costs, markets, and operating characteristics than the two pipeline companies used in this analysis, which serve primarily the Northeast.

Cost-Shifts Among Residential End-Users Are Affected by LDCs' Cost Distribution

The cost-shift experienced by a residential end-user will depend on how that end-user's LDC distributes increases in costs resulting from the creation of the capacity release market and the change in rate design. For example, according to our case study analysis of 73 LDCs served by the two pipeline companies, if LDCs pass all changes in costs to residential end-users, the residential end-users served by LDCs with lower load factors will experience somewhat greater increases in costs than the residential end-users served by LDCs with higher load factors.[21] As shown in figure III.3, we estimated that the residential end-users served by 47 of the 49 LDCs with moderate or low load factors would see a relatively small increase—up to 3 percent—in their cost of gas delivery. In contrast, we estimated that the residential end-users served by 16 of the 24 LDCs with high load factors would experience a modest decrease—up to 3 percent—in their cost of gas delivery.

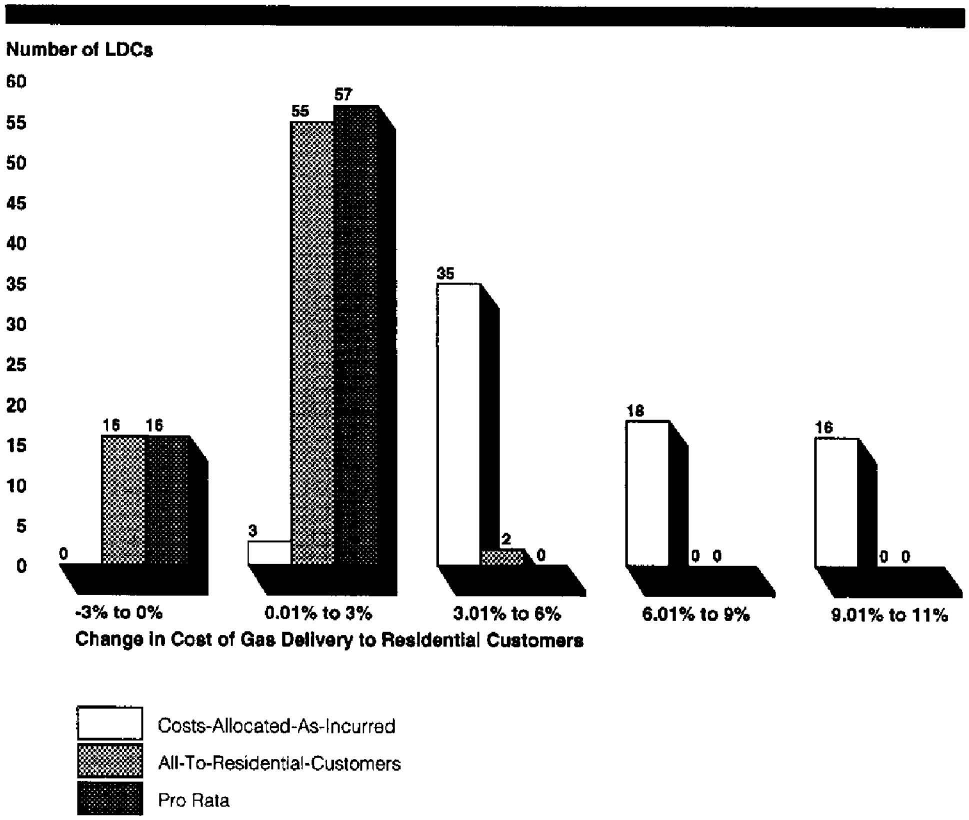
[21]We included in all our case-study analyses only LDCs that are "2-part" customers, i.e., that pay both commodity and demand charges. LDCs that pay only a commodity charge, such as many small municipal distributors, were excluded from our analysis. By definition, these customers will not experience changes in their demand charges.

Figure III.3: Estimated Change in the Cost of Gas Delivery to End-Users Under the All-To-Residential-End-Users Method



If LDCs pass along their changes in costs as incurred on behalf of their end-users, residential end-users will experience a larger increase in their cost of gas delivery than they would under other cost allocation methods. As shown in figure III.4, the residential end-users served by 16 LDCs may experience increases of between 9 and 11 percent, or, depending on the LDC, about $40 to $80 annually. In contrast, if LDCs pass cost increases exclusively to residential end-users based on the consumption of each end-user, residential end-users will experience smaller increases in their cost of gas delivery.

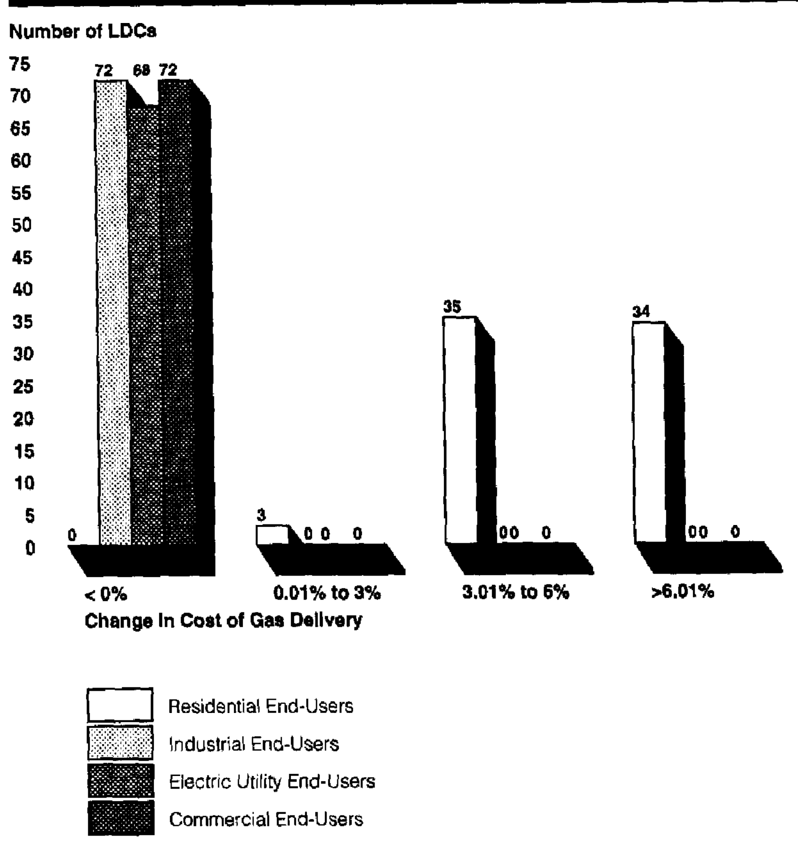
Figure III.4: Estimated Change in the Cost of Gas Delivery to Residential End-Users Under Different Cost Allocation Methods



Depending on how LDCs allocate costs, residential end-users may also experience greater increases in their cost of gas delivery than other end-users. For example, as shown in figure III.5, we estimated that if LDCs pass on their costs as incurred on behalf of their end-users, industrial and electric utility end-users served by every LDC in our analysis will experience a decrease in their cost of gas delivery. Industrial end-users served by some LDCs may see decreases of as much as 28 percent. At the same time, the residential end-users' gas bills would increase by at least 3 percent or about $15 to $20 annually in 69 of the 73 LDCs we analyzed.[22]

[22]For one LDC, we were unable to calculate the cost-shift to its residential end-users. As a result, 72 LDCs are shown in figure III.4 as serving residential end-users.

Figure III.5: Estimated Change in the Cost of Gas Delivery to End-Users Under the Costs-Allocated-As-Incurred Method



Cost-Shift Estimates Made by the Pipeline Companies

FERC has directed each pipeline company to estimate the possible changes in costs to each LDC (rather than end-user, as our analysis above does) resulting from the change in rate design alone. FERC asked each pipeline company to calculate the cost-shifts using the volumes of interruptible service and firm service that the pipeline company projects it will provide after Order 636 is implemented. FERC instructed each pipeline company, in calculating the revenues it would receive under MFV versus SFV rate design, to use the same projections of the volumes of interruptible and firm service in both cases. If the volumes transported are kept constant, the pipeline companies' calculations measure the effect of the change in rate design alone.[23]

[23]By holding the volumes constant, pipeline companies are not truly measuring the effect of changing the rate design alone. An accurate estimate of the effect of FERC's change in rate design would have to consider how the changes in prices resulting from the switch from MFV to SFV would affect LDCs' purchase mix between firm and interruptible transportation.

We believe that FERC's suggested method for calculating the cost-shifts among LDCs is questionable. FERC's methodology may cause the pipeline companies to understate the cost-shifts that they report. As explained earlier, the change in rate design shifts costs from end-users with interruptible service to end-users with firm service. By using, as a starting point in their analysis, volumes of interruptible service under MFV rate design that may be lower than those that were actually transported, the pipeline companies may understate the cost-shifts that result from the change in rate design. In other words, if there was little interruptible service before Order 636, there can be little shift in costs.

According to FERC officials, using the pipeline companies' figures on the volumes of firm and interruptible service in effect before Order 636 would also be problematic, given that LDCs were transporting most of their gas supplies during off-peak periods with interruptible service. The officials said that separating out the volume of interruptible service LDCs used would be very difficult. Furthermore, the FERC officials pointed out that most LDCs should not experience more than a 10-percent increase in their costs as a result of the change in rate design.[24] They said that any LDCs that do experience more than a 10-percent increase, despite FERC's efforts, could be eligible for a refund.

Factors Affecting Cost-Shifts

A number of factors will affect the final shift in the pipeline companies' fixed costs among LDCs and their end-users. Among these factors are (1) the ability of LDCs to offset some of their costs by releasing unneeded transportation and storage capacity to the pipeline company for resale to others via a prospective secondary market, (2) FERC and the pipeline companies' efforts to mitigate cost-shifts, and (3) the apportionment of these costs among end-users by state and local authorities.

The Capacity Release Market May Affect Cost-Shifts

FERC and some industry analysts contend that the capacity release market created by Order 636 could mitigate any increased costs faced by LDCs as a result of the switch from MFV rate design to SFV rate design. As LDCs resell their firm capacity in the secondary market, they may transfer all or some portion of the pipeline companies' fixed costs associated with that capacity to other end-users, such as industrial businesses and electric utilities.

[24]However, in one case FERC will allow an LDC's rates to increase by more than 10 percent because the distributor refused to relinquish some of its capacity under a seasonal contract.

The ability of an LDC to mitigate any increases in costs will depend primarily on two factors: (1) its ability to release capacity and (2) the prevailing prices in the capacity release market.

Ability of LDCs to Release Pipeline Capacity

Several officials representing small LDCs and municipal distributors informed us that they doubt whether they will be able to release capacity—particularly during periods of peak demand, when the capacity will command the highest prices. These analysts said that the amount of capacity that their LDCs will not need may be too small to be marketable. In addition, under Order 636, very small LDCs that do not pay a demand charge are prohibited from participating in the secondary market. Also, releasing capacity during peak periods may not be feasible, because most small LDCs do not own storage facilities to draw upon to meet their needs nor use alternative fuels (such as propane). An official representing industrial end-users said that he doubts that public utility commissions—the entities that regulate many LDCs—or local authorities will allow their LDCs to release much capacity, particularly during peak periods, since one of the primary responsibilities of public utility commissions is to ensure that end-users who lack alternative sources of fuel receive service on cold winter days.

Officials of pipeline companies and independent marketers maintain that there are solutions to these problems. Although small LDCs may not be able to release enough pipeline capacity individually to make the capacity marketable, LDCs could release capacity to marketers.[25] Marketers may be able to package the capacity released from several sources and thus provide the amount needed to make each LDC's released capacity marketable. Marketers can also provide storage, so that an LDC would not have to rely as heavily on its own capacity reservations during cold snaps. Some industry analysts also maintain that, although public utility commissions may be reluctant at the outset, they will allow their LDCs to release more capacity once they become aware of the prices LDCs can obtain in the secondary market and the opportunity costs of not releasing capacity. According to an official of a consumer advocacy group, state public utility commissions and consumer advocates will exercise oversight to ensure that LDCs attempt to release unneeded pipeline capacity in order to recoup some of the rates paid for pipeline transportation service.

Price of Capacity in the Secondary Market

Some officials of small LDCs and municipal distributors also doubt that the market price in the capacity release market will be high enough to allow the LDCs that release capacity to recoup a portion of their fixed costs.

[25]A marketer is an unregulated buyer and seller of gas supplies, transportation, and other services.

According to the Energy Information Administration, pipeline customers may have difficulty selling their unneeded capacity during off-peak periods when the demand for capacity is low. As a result, the supply of released capacity may greatly exceed demand, forcing the price of released capacity down to the variable cost of transporting the gas. Some analysts also contend that the pipeline companies may have advantages that allow them to undercut capacity prices offered by LDCs. Specifically, if the pipeline companies are essentially guaranteed recovery of their costs under SFV rate design, they would be able to price their interruptible service just over the variable cost of transporting the gas and still make a profit.

Others, including officials of the Department of Energy, believe that the problem with the secondary market is not that prices will fall too far, but that prices will not be allowed to rise to levels that clear the market—that is, ensure that the quantity supplied equals the quantity demanded. In the capacity release market, prices will be capped at the FERC-approved "just and reasonable" rate for firm transportation service. This cap could reduce the fixed costs that LDCs can recover as compared with what they could recover in a fully deregulated market. Because of this cap, LDCs may not be able to sell their capacity to offset the greater risks associated with their higher demand charges. The price cap may also reduce the efficiency gains that a secondary market could provide. For instance, the price cap could limit the ability of the secondary market to ration capacity during peak periods to those who value it most.[26] If prices for capacity reservations were allowed to move freely, the amount of capacity demanded would fall when reservation prices are rising and rise when reservation prices drop. This relationship between prices and capacity would help even out the use of the pipeline throughout the year.

LDC officials and state regulators point out that FERC had previously allowed LDCs to sell unneeded capacity at a price determined by the market, with no price caps. This system was referred to as a capacity brokering market. According to FERC, it had approved approximately 20 capacity brokering programs before issuing Order 636. State regulators would have preferred that FERC continue to make available the option of capacity brokering along with the FERC's preferred capacity release mechanism. According to a trade association representing LDCs, capacity

[26]The price cap could pose problems for purchasers of capacity as well as for sellers. If the market-clearing price exceeds the cap, purchasers may have to negotiate on terms other than price. For example, purchasers may be required to buy more capacity than they really need. Alternatively, the purchaser, to get capacity during peak periods, may also have to purchase capacity during off-peak periods.

brokering is superior to FERC's proposed capacity release mechanism because brokering permits the LDC and the end-users to negotiate an assignment of capacity that reflects the particular services the end-users need from the LDC. One LDC also argues that because existing capacity brokering programs are being terminated under Order 636, LDCs may now be forced to pay pipeline companies for a service that they can perform themselves in an efficient and more timely manner.

In response to this criticism, FERC asserts that it cannot completely deregulate the price of capacity in the secondary market because it has not been established that the market for released capacity will be competitive. According to FERC, data collected on the capacity brokering programs indicated that few transactions occurred and none involved the assignment of capacity on a firm basis. However, the paucity of transactions that occurred under the capacity brokering programs may be explained by the fact that purchasers of LDCs' unneeded capacity did not have the flexibility to use multiple receipt and delivery points on the pipeline system, as they will have under Order 636. Moreover, FERC determined that it could not prevent undue discrimination because it could not adequately monitor released capacity under these numerous capacity brokering plans.

According to an official representing industrial end-users, without a price cap LDCs may attempt to discriminate and charge industrial end-users above-market prices. However, since there are over 1,300 LDCs that may release their capacity, it is difficult to conclude at this time whether LDCs will be able to exert power in the secondary market.

FERC's task force on competition recently issued a report suggesting that the removal of price caps may make sense in markets where LDCs or others releasing capacity are unable to release sufficient amounts to give them market power.[27] The task force report noted that other factors, including the time of year the unneeded capacity is resold and the presence of competing interruptible or short-term firm service, can mitigate the potential for a single seller to attain power in secondary markets.

[27]Report of Commissioner Branko Terzic, Chairman, FERC Pipeline Task Force on Competition in Natural Gas Transportation (Washington, D.C.: May 24, 1993).

FERC and the Pipeline Companies Are Making Efforts to Mitigate the Cost-Shifts

FERC has prescribed that if there is a 10-percent or greater increase in costs to any one customer because of adoption of SFV rate design, the pipeline companies must mitigate the cost-shifts by using certain measures. FERC contends that a limit to the allowable increase in costs is necessary because SFV rate design is being adopted on a generic rather than a case-by-case basis. According to FERC, in certain circumstances some LDCS may experience an increase in rates that is slightly greater than or less than 10 percent.

To mitigate cost-shifts, FERC has suggested and approved the following measures: (1) special rates for small municipal distributors, so that such customers are required to pay only for the pipeline capacity they use; (2) seasonal capacity entitlements that allow all LDCS to reduce their capacity reservations during periods of the year, typically the summer months, when their end-users are not using as much natural gas; and (3) mixed rate-design methodologies that allow the pipeline companies to allocate their fixed costs under MFV (or any other rate design that allocates a portion of the pipeline companies' fixed costs to the commodity charge), but bill customers for their transportation capacity under SFV. According to FERC, the results of these mitigation measures could vary from one pipeline system to another. Therefore, one mitigation measure could be more effective than the other. Moreover, FERC has also approved other mitigation techniques proposed by the pipeline companies in the documents they filed with FERC describing how they plan to implement Order 636.

Small Customer Class Rates

FERC required the pipeline companies to consider developing special transportation rates for small LDC customers (those that consume less than about 10,000 cubic feet of gas per day). Under these rates, such LDCS would be charged only for the volume of natural gas that they consume. Unlike larger LDCS, these LDCS will not pay a demand charge to reserve their firm capacity. According to FERC, the small LDCS could realize cost savings under this approach if the pipeline companies design rates that assume the LDCS have a higher load factor than they actually do.

Seasonal Contracts

FERC suggested that the pipeline companies could also mitigate potential cost-shifts by allowing LDCS to lower their reservations for firm capacity on the pipeline at times of the year, typically the summer months, when they do not fully utilize their capacity rights. LDCS contract with pipeline companies for enough capacity to meet the needs of their firm-service customers—residential and commercial end-users—under severe cold weather conditions. Thus, LDCS often have rights to pipeline capacity that they do not fully utilize, particularly during the summer months when residential demand for space heating declines. Seasonal contracts create incentives for LDCs to lower their capacity rights during off-peak periods. When LDCs lower their contract demands during off-peak periods, the amount of the demand charges they pay goes down.

According to an LDC official, the use of seasonal contracts and the capacity release market could be very effective ways for LDCs with low load factors to mitigate their increased transportation rates under SFV rate design. However, FERC officials said that thus far, few pipeline companies have used seasonal contracts.

Mixed Rate Designs

FERC also suggested that the pipeline companies could mitigate potential cost-shifts by using different rate-design methodologies in devising the transportation rates to be paid by LDCs. FERC noted that the pipeline companies could use MFV or other rate designs to assign fixed costs to the reservation and usage charges, and use SFV for calculating the actual rates billed to LDCs. In other words, the pipeline companies can lower the rates certain LDCs must pay for firm service by reducing the amount of fixed costs that an LDC must pay in its demand charge. However, to the extent that one LDC's costs go down, another LDC's costs will go up; the pipeline company must be given an opportunity to fully recover its fixed costs.

Duration of Mitigation Measures

Initially, FERC expected all of the mitigation measures implemented by the pipeline companies, with the exception of the secondary market, to be removed after a 4-year period. In Order 636, FERC stated that the mitigation measures were intended solely to allow an orderly transition to SFV rather than to act as a permanent cap on cost-shifts to particular LDCs. However, in Order 636-B, FERC changed its policy; it will now allow the mitigation measures to continue indefinitely. According to FERC, the Commission's mitigation policy as it stands today represents a strong commitment to consumer protection. Industrial end-users believe that FERC's mitigation measures may undo some of the efficiency gains fostered by Order 636.

State and Local Authorities' Impact on the Apportionment of Costs Among End-Users

State and local authorities could ultimately determine how cost-shifts to LDCs will be apportioned among the end-users—residential, commercial, industrial, and electric utilities—they serve. State public utility commissions regulate the rates that investor-owned LDCs can charge their end-users. Local government authorities set the rates for municipal distributors.

According to officials of an LDC and the National Regulatory Research Institute, state and local authorities may be constrained in their ability to pass the higher transportation rates under SFV rate design to industrial and electric utility end-users because these end-users may (1) switch to an alternative fuel, (2) bypass the distribution company and hook up directly to a nearby interstate pipeline company, or (3) relocate their businesses to another area. In each case, residential and commercial end-users would be left with an even larger cost burden. Industrial businesses and electric utilities that bypass their LDCs in the future may have to pay some portion of the transition costs. (This issue is discussed in app. IV.) Order 636 indicates that FERC may require any customer that bypasses an LDC to pay some portion of the LDC's transition costs.

If past actions by state public utility commissions can be used as a predictor of future actions, then the increased rates LDCs may have to pay under SFV could be largely shifted to their end-users who have no alternative sources of fuel, i.e., residential and commercial end-users. According to a 1988 survey of 44 state public utility commissions and the District of Columbia, FERC's open-access transportation policies, which began with Order 436 in 1985, caused many public utility commissions to develop transportation policies for LDCs that enabled end-users, typically large industrial businesses, to purchase less-costly gas supplies directly from the producers and use the LDC to move the gas from the pipeline company to the end-user.[28] According to some state commissions, the implementation of these policies also caused LDCs to shift the pipeline companies' fixed costs from end-users who could switch fuels to captive end-users. The principal motivation of the LDCs in providing this service was to maintain market share and prevent large industrial end-users from bypassing the LDC to obtain lower prices for delivered gas directly from a nearby pipeline company.

[28]State Gas Transportation Policies: An Evaluation of Approaches, The National Regulatory Research Institute (Columbus, Ohio: Jan. 1989).

Transition Costs of Implementing FERC's Order 636

Order 636 will require about 76 interstate pipeline companies to restructure their operations and separate out their services—gas sales, transportation, and storage—for resale to LDCs and other firm-service customers, including industrial businesses and electric utilities that receive service directly from the pipeline company.[1] This appendix discusses the transition costs of implementing FERC's Order 636.

FERC Will Permit the Recovery of Four Types of Transition Costs

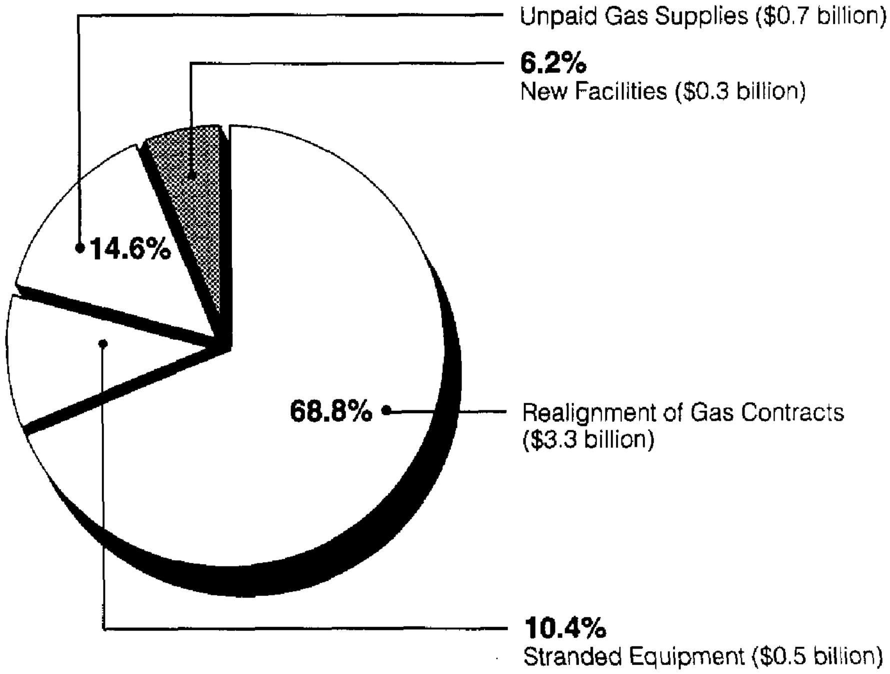
According to FERC, pipeline companies will be able to recover four categories of transition costs, including the costs for (1) realignment—modification or termination—of existing contracts with producers for gas supplies, (2) facilities that will no longer be needed or are stranded, (3) unpaid balances for gas supplies that the pipeline companies had sold to their firm-service customers, and (4) new equipment to better monitor and utilize gas supply and transportation services. According to FERC, three of these cost categories—realignment of gas supply contracts, stranded facilities, and unpaid balances for gas supplies—merely transfer costs from one industry segment to another. In other words, these are not new costs that the industry or society will have to incur. FERC contends that the costs in the fourth category—new equipment—are the only new costs that society will incur as a result of Order 636.

According to FERC, as of July 21, 1993, the pipeline companies' estimates of the transition costs to implement these new regulations totaled about $4.8 billion, of which only about $300 million represents new costs, as shown in figure IV.1.[2] However, according to FERC officials, this estimate is probably higher than the number FERC will finally approve because (1) the pipeline companies have assigned some of their existing contracts for gas supplies and transportation capacity on other pipelines to customers, (2) the spot-market price of natural gas has risen closer to the above-market prices of the pipeline companies' existing gas supply contracts, and (3) FERC has not yet reviewed and approved these estimates.

[1]FERC regulates about 150 interstate pipeline companies, but 74 pipeline companies do not have to file plans to show compliance with Order 636 either because they are small pipeline companies that do not need to make substantial changes to be in compliance with FERC's new regulations or because they have not accepted FERC's "blanket certificates." Such certificates enable pipeline companies to transport natural gas purchased directly by LDCs or large end-users.

[2]This estimate includes the pipeline companies' proposed costs for real-time metering facilities, if needed.

Figure IV.1: Preliminary Estimates of the Cost of Restructuring Pipeline Company Operations Under Order 636



Note 1: The new facility costs are new costs that society will incur because of FERC's Order 636. The unshaded cost categories are transfers in costs that society would have paid even without Order 636.

Note 2: FERC's recent estimate for realigning gas supply contracts excludes the costs (about $650 million) of one pipeline company's contracts with Canadian producers because the company plans to auction these contracts to other potential buyers. The difference between what the pipeline company paid for the contracts and what these contracts bring at auction will be the transition costs for realigning the contracts.

Source: GAO's analysis of FERC's data.

This estimate does not include all of the transition costs of several pipeline companies, including the costs of realigning certain gas supply contracts of one pipeline company that is currently involved in a bankruptcy proceeding.[3] According to FERC, some of this pipeline company's costs may be eligible for recovery under the new regulations. Moreover, this estimate does not include the new costs that LDCs and large end-users will incur to manage their own gas supplies and transportation capacity. (App. V discusses LDCs' new service costs in greater detail.)

Gas Supply Contracts

As figure IV.1 showed, $3.3 billion, or about 69 percent, of the costs of implementing the new regulations can be attributed to realignment of the pipeline companies' existing gas supply contracts with producers. Moreover, the costs of realigning the contracts could be higher than initially estimated because FERC has not put a restrictive cap on these costs; the pipeline companies may be able to recover some of these contract costs for several years.

In the past, the pipeline companies purchased natural gas at different prices from multiple producers under long-term contracts and resold the gas to LDCs and other firm-service customers. The pipeline companies' customers paid the weighted average cost of these contract prices for their gas supplies.[4] According to FERC, 23 pipeline companies have reported holding gas supply contracts that will need to be realigned.[5] The gas supply contracts of eight of these pipeline companies account for about $2.9 billion, or about 88 percent, of the total estimated cost of realigning contracts with producers.[6]

According to an official of an independent gas marketing company, the pipeline companies do not have many gas supply contracts today, but the

[3]Columbia Pipeline Company filed for bankruptcy on July 31, 1991, and went into reorganization before FERC issued Order 636. Producers have filed claims, which are being contested, against Columbia for about $11 billion in gas supply contracts. According to Columbia officials, the pipeline company had planned to recover the costs of realigning some of the contested gas supply contracts in line with the costs proposed by Texas Eastern Pipeline Company ($559 million) and Tennessee Gas Pipe Line Company ($442 million). On July 14, 1993, FERC issued an order on Columbia's compliance plan denying the pipeline company the right to recover 100 percent of any of the contested gas supply contracts under Order 636 and up to 75 percent of the contracts under previous FERC mechanisms to resolve these contracts. On September 29, 1993, FERC determined that some Columbia gas supply contracts, which are part of the bankruptcy proceeding, may be recoverable under the terms of a previous FERC-approved settlement agreement between the pipeline company and its customers. Moreover, according to FERC officials, other Columbia contracts that are not part of the bankruptcy proceeding may be recovered under Order 636. To date, Columbia has not filed to recover any such gas supply contract costs.

[4]The weighted average cost of gas is a formula used by the pipeline companies to determine the cost of gas underlying their rates; it is the total cost of gas divided by the total volume sold.

[5]As of July 21, 1993, 5 pipeline companies had not yet reported whether they will file to recover gas supply costs; 48 pipeline companies reported they will recover no gas supply costs.

[6]The costs for these contracts ranged from $175 million to $559 million.

contracts they have can be costly to realign. The official said, moreover, that realigning gas supply contracts with the Great Plains Coal Gasification project—the nation's first commercial-scale facility producing synthetic natural gas from coal—may represent as much as 20 percent of the total costs of realigning gas supply contracts. (See "Related GAO Products" at the end of this report.) In Order 636, FERC indicated that these gas supply contracts, held by four pipeline companies, could be recovered as transition costs. According to a FERC official, because of the federal government's long-standing involvement with these gas supply contracts, he doubted that FERC staff or others could legitimately challenge the prudence of these contracts. In the view of a consumer advocate official, LDCs and others should be given an opportunity to challenge the prudence of these contracts.

Unneeded Equipment

According to FERC, previous regulation of the interstate pipeline industry contributed to the development of an inefficient pipeline system. As a result, some pipeline facilities, which were not designed with "unbundled" transportation services in mind, will no longer be needed to supply service. In addition to physical plant, facilities can include capacity reservations and stored supplies of gas. These facilities may be stranded; that is, abandoned. For example, the pipeline companies may have (1) contracts—known as FERC account number 858 contracts—for transportation capacity with other pipeline companies or (2) natural gas supplies in storage that their customers do not want. In the past, the pipeline companies reserved capacity on other pipeline systems when their pipeline system did not connect with the production or storage areas needed to provide firm service to LDCs and other customers. The pipeline companies' preliminary estimates indicate that about $529 million worth of facilities or of contracts between pipeline companies or facilities may no longer be needed, accounting for about 10 percent of the total costs of implementing Order 636.[7]

Unpaid Balances for Purchased Gas

Under Order 636, the pipeline companies will no longer be allowed to automatically pass through their costs of purchasing gas dollar-for-dollar to customers. As noted above, the pipeline companies could formerly purchase gas supplies from multiple producers at different prices and charge their customers the weighted average of these contract costs. Under that system, a special account—known as FERC account number

[7]As of July 21, 1993, 19 pipeline companies had not filed estimates of their costs of abandoning unneeded equipment.

191—was used to track the difference between what the pipeline company paid the producer for gas and what the customer paid the pipeline company for the gas. According to preliminary estimates, the pipeline companies have as much as $708 million in unpaid balances for gas costs, or about 15 percent of the total costs of implementing Order 636.[8] According to FERC, all account number 191 costs that exist when restructuring becomes effective are counted as transition costs—but all are costs that the pipeline companies have already incurred for gas that has already been delivered to customers.

According to a FERC official, the pipeline companies had contractual obligations to pay producers for certain above-market-price gas supplies, which raised the pipeline companies' weighted average cost of gas supplies. LDCs and other firm-service customers would not purchase the pipeline companies' above-market-price gas supplies when there was little risk of service curtailment, typically during the summer months. Instead, during these periods of the year, LDCs and other firm-service customers bought less-costly gas supplies directly from the producers and had these supplies transported on an interruptible basis. The pipeline companies would assign their unrecovered costs to account number 191, where they compounded interest, until the company could recover them at a later date. However, the pipeline companies were not able to fully deplete these accounts and recover their costs, because LDCs would only purchase gas supplies from the pipeline companies when they could not risk curtailment of supply, typically during the winter months.

New Equipment

According to FERC, the restructuring of the industry will require the pipeline companies to install new equipment to ensure that end-users enjoy the benefits of a competitive market at the wellhead, or point of production. According to FERC, these costs represent the only new costs of implementing Order 636. Thus, FERC contends that the benefits of Order 636 need only exceed these costs to be real gains to society. Preliminary estimates of these new equipment costs are about $252 million, or about 6 percent of the total transition costs.[9] Although these equipment costs are lower than any of the other costs of implementing Order 636, this equipment—such as electronic bulletin boards to inform segments of the industry about the terms and conditions of available pipeline

[8]As of July 21, 1993, 15 pipeline companies had not filed estimates of their costs under account number 191.

[9]As of July 21, 1993, nine pipeline companies had not filed estimates of their new equipment costs.

capacity—may have the greatest importance for increasing industry competition, according to some industry officials.

Electronic Bulletin Boards

FERC recognizes that access to information and nondiscriminatory information transfer are vital to a well-functioning, competitive marketplace. Thus, in Order 636 FERC mandated for the first time that the pipeline companies use electronic bulletin boards. According to FERC, at least 43 pipeline companies have been using electronic bulletin boards since 1988, when FERC encouraged the pipeline companies to make data on transportation capacity electronically available to the public 24 hours a day. However, a FERC study of these early electronic bulletin boards showed that it was difficult or impossible to locate or download information from the boards, and they did not always contain the required information. As a result, in Order 636 FERC required that the pipeline companies develop user-friendly bulletin boards and provide producers, marketers, and customers with equal and timely access to data on the availability of transportation service through these bulletin boards.

Under Order 636, the pipeline companies are expected to provide complete and timely information about available transportation capacity and transactions with marketing affiliates—pipeline-owned subsidiaries that buy and sell gas supplies at unregulated rates—on publicly accessible electronic bulletin boards in order to allow detection and deterrence of discriminatory practices by the pipeline companies. In a May 1993 report, we recommended that FERC aggressively enforce the pipeline companies' compliance with its reporting requirements aimed at detecting and detering such practices.[10]

Measuring Equipment

Metering facilities measure the amount of natural gas entering or leaving a given point on the pipeline system, usually where natural gas enters the system from production areas or other pipelines and where the gas is resold to LDCs or other customers. Requests for service from individual receipt points—where gas enters the pipeline system from production areas—to individual delivery points—where gas is delivered to the customer—are expected to increase substantially under Order 636. Under the order, the gas industry must track whose gas is being bought; where it enters the pipeline system; and how much gas is being delivered to whom, on what day, and at what cost. The pipeline companies will assess penalties against LDCs and other customers that take more gas than their contracts allow. Metering information will be essential to track these

[10]Natural Gas: FERC's Compliance and Enforcement Programs Could Be Further Enhanced (GAO/RCED-93-122, May 27, 1993).

potential penalties, and thus in some cases there may be a need for more costly real-time metering capability. (App. V discusses these "imbalance" penalties in more detail.)

Pipeline Companies Can Recover 100 Percent of the Transition Costs

FERC will allow the pipeline companies to recover 100 percent of all transition costs that are directly attributable to the new regulations and prudently incurred. Up to 90 percent, or about $3 billion, of the currently estimated costs of realigning gas supply contract costs can be billed directly to firm-service customers, and up to 10 percent, or about $300 million, can be recovered from interruptible-service customers. Firm-service customers will pay 100 percent, or about $700 million, of the unpaid balance for gas supplies already delivered. Moreover, they will pay these costs over 12 months or some other reasonable period. The costs of new facilities will be included in the pipeline companies' cost of service and billed to firm-service customers and interruptible-service customers alike. The other transition costs will be amortized over a period of several years. Officials representing municipal distributors believe FERC should require the pipeline companies to absorb the interest charges on these amortized bills as a way to produce more equitable sharing of the transition costs.

According to an industry financial analyst, although the pipeline companies are required, under Order 636, to recover up to 10 percent of their costs of realigning gas supply contracts from interruptible-service customers, it is not certain that they will be able to recover these costs. FERC officials believe that some pipeline companies may not have much interruptible capacity to sell after Order 636 is implemented. Other industry analysts and a recent National Petroleum Council study suggest that the interstate pipeline companies are not fully subscribed or are not operating at full capacity.[11] According to the council, in 1991 about 19.2 trillion cubic feet of natural gas was transported through a pipeline system that it believes is capable of delivering about 24 trillion cubic feet per year. Thus, the interstate pipeline companies in certain regions of the country may have excess capacity to market on either a firm or interruptible basis beyond the demand of their current customers.

According to FERC, LDCs and other customers with firm-service contracts are expected to more fully utilize their pipeline capacity under Order 636, since they will pay lower usage rates to transport gas under the mandated

[11]The Potential for Natural Gas in the United States, National Petroleum Council (Washington, D.C.: Dec. 17, 1992).

straight fixed variable (SFV) rate design. Moreover, FERC believes that LDCS and other firm-service customers will release their unneeded pipeline transportation capacity, which can include storage capacity, to the pipeline company for resale. (The prospective capacity release market is discussed in app. III.) In some cases, the released capacity may be subject to recall provisions that restore the capacity to the original owner on demand.

To the extent that there is little or no interruptible capacity on pipeline systems, FERC does not intend for the pipeline companies to assign the full 10 percent of the gas supply realignment costs to a limited number of customers with interruptible service, nor absorb the costs itself. Instead, FERC has indicated that the pipeline companies can request new rates to recover these costs from customers with firm-service contracts. However, according to a FERC official, the pipeline companies must demonstrate that their customers with interruptible-service are not willing to absorb 10 percent of the transition costs (i.e., they would switch to an alternative fuel) before FERC will allow them to recover these costs from firm-service customers.

Transition Costs Will Raise Certain Residential End-Users' Gas Bills Over the Next 3 Years

A trade association representing the interstate pipeline companies recently estimated that the average residential end-user could pay $12 more per year in gas bills for 3 years as the pipeline companies recover their transition costs. This estimate assumes that the transition costs will be billed to different classes of end-users, including industrial businesses, commercial firms, and electric utilities, in proportion to their annual consumption of gas. Using the same assumption, we estimate that the average residential end-user could pay about $21.50 more in the first year and $14 more per year in each of the next 2 years. As a worst-case scenario, if LDCS allocate all the transition costs only to residential end-users, we estimate that the average residential end-user could pay about $84 more in the first year and $55 per year for each of the next 2 years.[12]

We believe that the average residential end-user is likely to pay less than $55 per year for 3 years but more than $14 per year for 3 years. LDCS will likely bill the end-users of firm service, including residential, small commercial, and some industrial-process end-users, for most, if not all, of the transition costs. However, because complete data were unavailable on

[12]The transition costs for unpaid gas supplies will be recovered in the first year after implementation of Order 636. The other transition costs, excluding new equipment costs, are likely to be recovered over 3 years.

the amount of natural gas sold or transported to industrial end-users on a firm basis, we cannot estimate the precise dollar amount that the average residential end-user could pay. Moreover, the actual amount that individual residential end-users may pay will depend on a variety of factors, such as the amount of the transition costs each pipeline company bills to LDCs and the allocation strategy of individual LDCs. For example, 25 pipeline companies have reported that they will incur no transition costs. Thus, end-users of the LDCs served by these pipeline companies should experience no increase in their gas bills attributable to the recovery of transition costs. (See app. VII for more details on our estimate of transition costs to be paid by residential end-users.)

Pipeline Companies' Customers Would Have Paid Most of the Transition Costs Under Previous FERC Regulations

In the absence of Order 636, the pipeline companies would likely have recovered from their customers most of the costs that are now considered transition costs.[13] The pipeline companies would likely have recovered all of their costs for interpipeline transportation contracts and obsolete equipment; unpaid gas supplies; and new equipment, including electronic bulletin boards.[14] In addition, the companies would have recovered most of their costs for above-market-price gas supply contracts. Previous to Order 636, the pipeline companies recovered their costs for above-market-price gas supplies in several ways. First, under Order 528, many pipeline companies terminated or modified these contracts with producers and recovered on average about $6.4 billion, or about 64 percent, of these costs from their customers.[15] Second, according to a FERC official, FERC later approved several gas inventory charges that were intended to fully compensate those pipeline companies that still had above-market-price gas supplies for their willingness to stand ready to

[13]We were unable to calculate the precise amount of transition costs that would have been recovered by the pipeline companies even without Order 636 because information on the costs that pipeline companies recovered on their above-market-price gas supply contracts is incomplete.

[14]Order 636 will accelerate and perhaps raise the cost of certain new equipment, such as electronic bulletin boards and telemetering equipment, that some pipeline companies had already begun to purchase and recover in their rates for transportation services.

[15]Under Order 636, these costs will be about $3.3 billion. If the pipeline companies had to bear 36 percent of these costs under Order 636, they would have to pay about $1.2 billion, or about 25 percent of the estimated $4.8 billion in total transition costs. The remaining 75 percent, or $3.6 billion, of the transition costs would have been paid by the pipeline companies' customers.

supply gas to their customers.[16] The pipeline companies assessed this charge when their customers did not purchase an agreed-upon threshold of gas supplies. Finally, according to a FERC official, some pipeline companies may have billed their captive customers for the above-market-price gas supplies.

Preliminary Cost Estimates May Be Worst-Case Scenarios

FERC expects its staff and others, such as LDCs, to review each pipeline company's proposed transition costs to determine (1) whether they are eligible for recovery and (2) whether the pipeline company prudently incurred the costs. According to FERC and some industry officials, the industry's preliminary cost projections should be considered worst-case scenario estimates for those pipeline companies that have reported such costs.

Eligibility Test

Officials from an LDC and a consumer advocacy group have expressed concerns that some costs reported by the pipeline companies, particularly certain costs resulting from gas supply contracts, cannot be directly attributed to the implementation of Order 636. According to an official of a consumer group, the pipeline companies should have renegotiated these gas supply contracts and recovered their costs under previous FERC regulations. Under these previous regulations, the pipeline companies could recover only up to 75 percent of their contract obligations to pay producers for gas that the pipeline company did not sell. These obligations are known as "take-or-pay" costs. According to FERC, the pipeline companies' gas supply contracts with producers will be closely scrutinized to determine whether the pipeline companies can recover 100 percent of these costs; the pipeline companies will not be allowed to recover these costs unless they result from the new regulations. FERC recently issued an order on the compliance plan of one pipeline company that set out procedural guidelines for the recovery of transition costs. These guidelines may be applied for each of the pipeline companies affected by Order 636.[17] FERC will convene a conference open to all parties to determine whether a pipeline company's costs are eligible for recovery. Once the conference is

[16]FERC does not have information on whether pipeline companies were fully compensated for their willingness to provide stand-by gas supplies, since these gas-inventory-charges were approved as part of confidential settlement agreements between the pipeline companies and their customers. According to officials representing the municipal distributors, because these charges were negotiated in settlement agreements, they represented a partnership in which the burden of the above-market-price gas supplies was shared.

[17]Texas Eastern Transmission Corporation, RP93-125-000, Order Accepting and Suspending Tariff Sheets Subject to Refund and Conditions, and Establishing a Hearing and a Technical Conference, (1993) p. 9.

completed, a hearing will be held before a FERC administrative law judge so that the pipeline company's customers may challenge the transition costs and prove they were imprudently incurred.

According to a former FERC Commissioner who was in office at the time of our review, it is imperative that FERC establish time limits for the recovery of transition costs under Order 636. He said that the costs that the pipeline companies incurred under previous FERC orders should not eligible for 100-percent recovery under Order 636. However, it is not yet clear how FERC will determine whether the pipeline companies' costs for realigning gas supply contracts are eligible for full recovery. A FERC official said that it has not yet been decided whether a cut-off date, such as April 8, 1992—the date Order 636 was issued—will be used to determine whether the pipeline companies may recover 100 percent of their contract realignment and other transition costs. According to FERC, any realignment costs that are determined not to be eligible for 100-percent recovery under Order 636 may be eligible for up to 75-percent recovery under FERC's other mechanisms to relieve the pipeline companies of take-or-pay costs.

Prudency Reviews

FERC will require the pipeline companies to file a request for new rates to recover certain transition costs. According to FERC, the rates resulting from these filings will be put into effect subject to refund. However, if the pipeline companies collect revenues from customers to recover their costs, and FERC later determines that these costs were not prudently incurred, the revenues will be refunded to those customers. Moreover, the pipeline companies will not be allowed to recover these costs until they are actually incurred. LDCs, other customers, and FERC staff will be able to review the actual costs and challenge whether they were prudently incurred. According to FERC, prudence dictates that the pipeline companies negotiate vigorously with and at arms length from their producer/suppliers in a bona fide effort to minimize the transition costs. If FERC finds that a pipeline company did not adhere to this standard, the company will not be allowed to recover such imprudently incurred costs. According to an industry analyst, however, given the history of FERC regulation, this scenario vastly overstates FERC's ability or willingness to deal with issues of prudence.

Certain Factors Could Affect the Recovery of These Transition Costs

According to FERC, certain transition costs could be mitigated if LDCs, other firm-service customers, or others take over the pipeline companies' existing gas supply contracts with producers, or the companies' transportation agreements with other pipeline companies. If LDCs or other customers assumed these contracts, they could obtain the benefits of guaranteed gas supplies or transportation capacity on other pipelines. For example, FERC recently approved a proposal by a pipeline company to assign its capacity rights with another pipeline company to a producer in exchange for relief from contracts to purchase gas supplies. As a result, this pipeline company has reduced its overall transition costs by about $200 million. It may be to the advantage of the pipeline companies' firm-service customers to assume existing contracts. If they do not, they may end up paying the cost of realigning the contract and yet not get the benefit the contract provides for transportation capacity of gas supplies.

FERC requires the pipeline companies to estimate their expected volumes of interruptible transportation when it approves new rates for these services. The pipeline companies recover some of their fixed costs through the rates they charge for interruptible service. In the past, according to FERC staff and an industry official, the pipeline companies routinely underestimated their volumes of interruptible transportation. As a result, the pipeline companies could sell more interruptible transportation than they estimated and thereby collect revenues that exceed their fixed costs.

FERC has required one pipeline company to offset its costs to realign gas supply contracts with revenues that may be generated from future sales of interruptible transportation. Specifically, FERC will require the pipeline company to apply 90 percent of the revenues generated from any incremental sales of interruptible transportation capacity above its projections to offset its costs of realigning gas supply contracts. The pipeline company will be allowed to keep 10 percent of the revenues from such sales.

According to a FERC official, FERC's general policy is to require that the pipeline companies credit firm-service customers for additional purchases of interruptible service above their projections, irrespective of whether the companies are recovering contract realignment costs. Again, the pipeline companies will be allowed to keep 10 percent of the revenues from such sales. Officials representing industrial businesses are opposed to this crediting mechanism. They believe it dilutes the incentives of firm-service customers to release capacity. The officials are concerned that firm-service customers will not offer released capacity competitively, but may simply withhold capacity from the market and await their share of whatever interruptible transportation revenues are generated. In addition, industrial end-users believe that allowing the pipeline companies to recover only 10 percent of their incremental sales of interruptible service is an insufficient incentive for the pipeline companies to market their excess capacity.

FERC will also allow some pipeline companies to retain existing contracts with producers as long as they can show that they can minimize overall transition costs by continuing to purchase gas under these contracts. FERC will require the pipeline companies that retain gas supply contracts to determine the difference between their above-market-price contracts and the higher of (1) the pipeline companies' actual sales price to purchasers or (2) an objective index of average market prices. The pipeline companies are then required to credit sales from their below-market-price gas contracts to the costs customers must pay to realign the pipeline companies' above-market-price contracts. FERC will allow some pipeline companies to use this "price differential" mechanism for an initial 2-year period. At the end of this period, the pipeline companies will have to show why the continued use of this mechanism or another recovery mechanism is necessary. An official of a consumer group expressed concern that FERC will allow the pipeline companies to bill LDCs for the recovery of the price-differential costs before showing that these costs were properly incurred.

According to an official representing interstate pipeline companies, recent rising prices for natural gas should diminish the costs the pipeline companies will incur to realign their above-market-price contracts for gas supplies. The pipeline companies are expected to pay producers the amount necessary to realign these contracts with market prices. Moreover, according to the official, the Energy Information Administration estimates that natural gas prices will rise by about 8.1 percent in 1993 and by 9.5 percent in 1994. Thus, the costs to realign gas supply contracts could decrease.

In implementing FERC's new regulations, some LDCs and pipeline companies have negotiated settlements that mitigate the transition costs certain LDCs will have to pay. For example, FERC has approved an implementation plan for one pipeline company in which very small customers, including municipal distributors, are excused from having to pay costs to realign gas supply contracts. As a result, however, larger distribution companies and interruptible-service customers may have to absorb more transition costs, since the pipeline companies are assured full recovery of the costs of implementing the new regulations. According to a Department of Energy official, the implementation of Order 636 through settlement decisions between the pipeline companies and their customers could reduce the efficiency gains and degree of competition FERC sought for the industry when it promulgated the new regulations.

Finally, according to an official representing pipeline companies, the Minerals Management Service of the Department of the Interior has issued a new policy to recover royalties on payments the pipeline companies previously made to buy down or buy out contracts with producers for gas supplies. Natural gas producers typically do not own, but lease, the rights to underground minerals on properties where they operate. In addition to paying bonuses and other considerations to obtain lease rights, the producers are usually obliged to give the mineral owner a royalty; that is, a specific share of the gross production either in the form of gas or cash proceeds from the property free and clear of any production costs.

If the federal government is successful in recovering royalties on these payments, some LDC officials believe that private landowners will also seek to recover royalties from the producers. The official representing pipeline companies said that the Department of Interior's policy would not effect the pipeline companies' overall estimates of the costs ($3.3 billion) of realigning gas supply contracts with producers under Order 636. However, according to this official, the policy could stiffen the resolve of producers to negotiate higher settlements with the pipeline companies on the cost of realigning gas supply contracts. Moreover, according to an official of a consumer advocacy group, some pipeline companies indemnified producers against the possibility of having to pay royalty payments on the costs of realigning previous gas supply contracts. Thus, the pipeline companies' estimate of gas supply realignment costs may not come down as much as it otherwise could have. A trade association representing independent producers opposes the Department of Interior's new policy and has filed suit in a federal court to obtain an injunction preventing the Department from collecting royalties on previously resolved gas supply contracts.

Recovery of the Transition Costs Is a Contentious Issue

As with previous FERC regulatory changes, the question of who pays the transition costs to implement the new regulations is a contentious matter. Members of Congress, state and local authorities, and officials representing LDCs and consumer advocacy groups have all expressed concerns about whether the sharing of transition costs is equitable and whether the pipeline companies have enough incentives to minimize these costs, since they are assured full recovery. These concerns continue even though FERC, in a recent response to a congressional inquiry, contended that consumers will experience net savings as a result of Order 636.

Equitable Sharing of Transition Costs

A number of LDCs, state regulatory agencies, and consumer groups believe that FERC's requirement that end-users of firm-service be billed for most of the transition costs of implementing the new regulations does not result in an equitable sharing of the costs. For instance, an official of a consumer advocacy group said that many of the gas supply contracts that remain to be realigned under Order 636 were based on expected industrial end-use consumption. Officials from some of these groups have argued that all the costs of realigning gas supply contracts should be absorbed by the pipeline companies and producers, since these industry segments will be the primary beneficiaries of the new regulations. They argue that FERC previously allowed producers to voluntarily abrogate or nullify their gas supply contracts with the pipeline companies under FERC's Order 451 and should now require the pipeline companies to do the same. In addition, they believe that FERC has given the pipeline companies and producers ample opportunity to realign their contracts and recover up to 75 percent of their take-or-pay costs under other FERC-approved cost recovery mechanisms. In their view, the pipeline companies should not be allowed to recover 100 percent of these costs now because they chose not to realign these contracts earlier. According to an official of a consumer advocacy group, the industry was successfully buying out the remaining contracts for the above-market-price gas supplies before Order 636 even when the pipeline companies were expected to absorb some of the costs.

This official also notes that FERC believes all segments of the industry will benefit from the new rules. Yet firm-service customers, who cannot easily switch to alternative fuels, are burdened with paying most of the costs of restructuring the industry. For example, FERC expects all segments of the industry to benefit from the new equipment the pipeline companies will install to provide better information about available pipeline capacity and deliveries of natural gas supplies. Pipeline companies, producers, gas marketers, LDCs, and customers with interruptible service, such as industrial end-users, are all expected to use the pipeline-company-operated electronic bulletin boards and measuring equipment to buy or sell available pipeline capacity and track deliveries of natural gas supplies.

However, according to several former FERC Commissioners who were in office at the time of our review, the pipeline companies would likely have incurred the costs of installing this new equipment even in the absence of FERC's new rules. As a result, these costs would have been included in the pipeline companies' fixed costs and recovered through the rates for firm and interruptible service. Although these costs may have been recovered anyway, officials representing municipal distributors believe that Order 636 will inflate the cost of these facilities. They believe FERC's mandate that the pipeline companies quickly develop electronic bulletin boards to operate under the order will lead to inefficient expenditures that the companies can recover dollar-for-dollar.

Officials representing producers and pipeline companies collectively maintain that LDCs and their end-users were the primary beneficiaries of FERC's earlier regulatory changes. Moreover, according to these officials, the producers and pipeline companies already absorbed sizeable take-or-pay costs associated with the implementation of FERC's previous regulations to restructure the industry and thus should be exempt from paying the costs associated with FERC's new rules. LDCs deny these contentions. They argue that they were denied any opportunity to contest the prudence of the earlier take-or-pay costs, yet were required to pay between 75 and 100 percent of such costs. Industrial end-users, which generally use interruptible transportation service, argue that since they did not purchase gas from the pipeline companies, they did not benefit from the gas supply contracts between pipeline companies and producers and thus should not be responsible for any costs incurred to terminate or realign these contracts. (App. VI discusses the take-or-pay costs paid by each industry segment after the implementation of previous FERC regulatory changes.)

FERC's Chair, in her previous capacity as a Commissioner, dissented in part from the Commission's approval of the recovery mechanism for transition costs in Order 636-A. She reasoned that FERC could best spread the transition costs of Order 636 across all segments of the industry by requiring the pipeline companies to recover the costs of realigning gas supply contracts through a 25-percent surcharge to their customers based on the volume of natural gas transported. FERC's Chair also dissented in part from the new regulations on the grounds that customers with interruptible service should bear more than 10 percent of the costs of realigning gas supply contracts. She reasoned that a 90/10 split for recovering costs from firm-service and interruptible-service customers does not adequately reflect the benefit interruptible-service customers are receiving as a result of the restructuring of the industry. As noted in appendix II, the transportation rates paid by customers with interruptible service were reduced when the pipeline companies began, in 1989, to use a rate design that enabled the pipeline companies to collect most of their fixed costs (minus return on equity and related income taxes) in the demand charge paid by customers with firm service. Moreover, according to an industry study, interruptible-service customers have received about $43 million annually in selective discounts from the pipeline companies.

FERC's Chair further stated that the transition costs should be recovered in proportion to a customer's use of the pipeline system or through the commodity charge. The surcharge favored by the Chair could also indirectly affect the pipeline companies and producers. Certain pipeline companies, particularly those competing with other pipeline companies in some markets, may pay indirectly by having to discount their transportation rates for firm and interruptible service to attract business. To the extent that the pipeline companies have to discount their services, producers may correspondingly receive lower prices for their gas supplies. However, according to one of the Chair's assistants for natural gas issues, no data or analysis have been produced by either the pipeline companies or the producers to substantiate their claims that recovery of the transition costs through surcharges on volumetric usage would affect their profitability.

FERC's Chair has recently observed that, despite her dissent on how these transition costs could best be recovered, the Commission's decision now has the force of law under FERC's regulations and must be enforced.

Pipeline Companies' Incentives to Minimize Transition Costs

As discussed above, FERC did not require pipeline companies and producers to share in the costs of implementing Order 636. As a result, some industry analysts question how much incentive the pipeline companies will have to minimize the costs of contract realignment. According to an association representing municipal distributors, Order 636 gives the pipeline companies even more discretion to expend money to realign gas supply contracts than these companies would have had under previous FERC mechanisms to recover these costs. However, according to FERC, FERC's eligibility and prudency tests are designed to ensure that the pipeline companies and producers make good-faith efforts to attempt to lower the costs of realigning gas supply contracts through negotiation.

Also, according to officials representing major producers, the pipeline companies' estimates of the costs of realigning these contracts should be regarded as upper-limit estimates. These officials contend that the pipeline companies have not yet begun to negotiate with producers on these contracts. The officials said, however, that contrary to most expectations, the pipeline companies will negotiate with producers to terminate—or buy out—and renegotiate—or buy down—their gas supply contracts. They said that LDCs and FERC, through its prudency reviews, will ensure that the pipeline companies make a good-faith effort to minimize contract realignment costs. In addition, according to officials representing the interstate pipeline company trade association, the pipeline companies will negotiate hard to minimize the costs of renegotiating these gas supply contracts because they do not want to transfer revenues to the producers. Under Order 636, the pipeline companies may compete with these producers and marketers for sales of natural gas supplies.

A national association representing consumers believes that FERC could employ stronger measures to ensure that the pipeline companies minimize their contract realignment costs. The association noted that many of the contracts have clauses that provide for contract abrogation if government action makes it impossible to fulfill the contract or if actions of the market have a similar effect. The association argued that FERC should refuse to allow the pipeline companies to pass costs through to consumers if they do not make use of these clauses to reduce the monetary responsibility for the contracts.

FERC Claims Net Cost Savings From the Elimination of Existing Gas Supply Contracts

FERC claims that customers will realize net costs savings when above-market-price gas supply contracts are realigned to contracts with market-based prices. FERC estimated that end-users would save between $3.4 billion and $8.7 billion from the change to market-based gas prices. As noted above, the pipeline companies' preliminary estimates of the costs of terminating above-market-price gas supply contracts total about $3.8 billion. To arrive at its estimate, FERC calculated the difference between what LDCs would have paid for the pipeline companies' weighted average cost of above-market-price gas supplies over the life of the contract and estimates of lower short-term or spot-market prices for gas supplies in the future.

According to officials representing a large LDC and municipal distributors, however, FERC's analysis of the benefits to be derived from eliminating existing gas supply contracts is flawed. FERC assumed that future market prices would resemble the then current spot-market prices. That spot-market price was a measure of the cost to deliver gas on a 30-day basis. Thus, FERC may overstate the benefit of eliminating the pipeline companies' sales service. Officials representing municipal distributors and an independent marketer believe that future spot-market prices will be higher. They noted the recent increase in these prices—prices for gas futures increased from about $1.91 per thousand cubic feet of gas in March 1993 to about $2.76 per thousand cubic feet of gas in May 1993—as an indicator of this trend.[18] Moreover, according to the official representing municipal distributors, gas supply costs will also be higher in the future because (1) distributors will contract for longer-term firm delivery; (2) producers will assess demand charges for gas supplies; and (3) LDCs will pay premiums to producers for the right to vary or swing the amount of natural gas that producers deliver to meet the hourly and daily consumption patterns of the LDCs' end-users; and (4) with the elimination of fixed costs in the commodity charge under SFV rate design, producers will be able to raise prices closer to the price of alternative fuels.

This official also believes that it is not yet clear whether the elimination of the pipeline companies' monopsony power over gas purchases is a benefit. He believes that the bundled service that the pipeline companies formerly provided was superior in price and supply reliability to the separate services LDCs will receive from producers, marketers, and pipeline companies. The services that LDCs will have to contract for to replicate the bundled service that the pipeline companies formerly provided are discussed in appendix V.

[18]The price of June 1993 gas futures contracts dropped to about $2.12 per thousand cubic feet. On September 2, 1993, the price of October gas futures contracts closed at $2.41 per thousand cubic feet.

New Costs for Local Distribution Companies

LDCs will incur new costs to replicate the services previously provided by their pipeline companies. This appendix discusses the types of new services LDCs may contract for to obtain reliable delivery of natural gas supplies and the major issues surrounding these additional costs.

Type and Extent of the New Service Costs

According to LDC officials, LDCs will incur new costs to (1) purchase gas supplies; (2) enter into interpipeline transportation contracts; (3) build or lease storage capacity, (4) release their unneeded pipeline transportation capacity for resale; (5) pay other parties to perform these services; or (6) pay penalties, known as overrun or imbalance penalties, to the pipeline companies when they use more firm transportation service or put more or less gas into the system than their contracts allow. Parenthetically, an official representing industrial end-users said that industrial businesses may also incur these costs as they cope with their new responsibilities under the order.

The total costs compared with the benefits of these new services have not been determined and will differ among LDCs. Officials of municipal distributors estimate that purchasing separately the services that the pipeline companies used to provide LDCs as a bundle will cost as much as 40 cents to 60 cents more per thousand cubic feet (mcf) of delivered gas than LDCs used to pay for the combined services. However, according to officials representing large LDCs, some distributors, particularly large LDCs, may be able to lower their costs by obtaining their own gas supplies.

Gas Supply Contracts

LDCs' costs could increase as they add the staff and equipment necessary to assume full administrative responsibility for purchasing their own gas supplies from multiple sellers. Since FERC issued its initial open-access regulations in 1985, many large LDCs and some smaller LDCs, including municipal distributors, have purchased some of their gas supplies under 30-day contracts directly from producers, particularly during off-peak periods. In 1992, LDCs purchased about 38 percent of the natural gas transported by the pipeline companies directly from producers.[1] In addition, LDCs purchased gas supplies through marketers—unregulated buyers and sellers of gas supplies. However, no data are available on these transactions.

[1]Carriage Through 1992, Interstate Natural Gas Association of America, Report No. 93-2 (Washington, D.C.: July 1993).

LDCs will be entirely responsible for their own gas supply purchases from the date FERC approves each pipeline company's final plan for complying with Order 636.[2] After that time, the pipeline companies will not be required to provide back-up supplies of natural gas to LDCs. According to an industry analyst, LDCs will likely purchase much more of their gas supplies under longer-term contracts than they previously did in order to ensure gas supplies. According to an industry analyst, the average number of contracts that LDCs will have to negotiate in the future is likely to decline, as a result of the shift from spot-market supplies to long-term contracts. The analyst believes there is likely to be a near-term increase in the cost of administering these contracts because although there will be fewer contracts, the long-term contracts must deal with issues that can be ignored in a short-term contract. However, over the medium and long terms, the cost of administering a stable set of long-term contracts should be less than the cost of constantly renewing a set of short-term contracts.

According to an official of a municipal distribution company, as a result of the costs of implementing Order 636—such as the need to hire additional staff—some municipal distributors may be unable to remain in business and will be bought out by larger distributors. Moreover, the official said that such buyouts will adversely affect local taxpayers, because municipal distributors have been used as a source of revenue to offset local property taxes.

The price of gas supply contracts will vary with the terms and conditions specified by the LDC. Officials of some LDCs said they plan to diversify their portfolio of gas supplies. Thus, they will buy some supplies on a short-term or spot-market (30 days or less) basis, some on an intermediate (1 month to 1 year) basis, and some on a long-term (over 1 year) basis. An official of an independent marketing company said that the majority of new long-term firm contracts will be indexed to changes in spot-market prices. No one can predict what the price of future spot-market gas contracts will be. Nonetheless, the independent marketer official expects prices to rise over time and pointed to the run-up in futures prices from about $1.91 mcf in March 1993 to about $2.76 mcf in May 1993 as an indicator of this trend.

LDC and marketer officials said that the contracts LDCs are negotiating with gas sellers contain provisions enabling them to vary their consumption patterns on a seasonal, monthly, and daily basis: These provisions are

[2]FERC expects all pipeline companies to be in full compliance with Order 636 by the winter heating season of 1993-94, which begins on November 1, 1993.

known as "swing rights." The more flexibility an LDC requires in its swing rights, the higher premium it will pay. According to a marketer official, swing rights can be a less expensive replacement for storage capacity. Finally, LDC and producers officials said that LDCs will pay producers a demand charge for these supplies. They said that LDCs will pay this charge whether or not they take delivery of the gas supplies. According to officials representing major and independent producers, these fees provide producers with a more stable revenue stream. This fee could represent about 10 percent of the total sales price of the gas supplies.

LDC officials said that they will buy gas supplies from a number of sellers, including producers, marketers, pipeline companies, and other distributors because they do not want to risk a disruption in supplies from any one source.[3] Natural gas wells stop operating periodically because of mechanical failure or weather conditions, such as hurricanes. LDCs, as utilities possessing exclusive franchise rights from their public utility commissions or local authorities, are required to serve any person requesting service and must maintain adequate supplies to serve all end-users' demands.

In addition, given the potential for price volatility in an unregulated gas supply market, some LDC officials said that they might protect themselves or hedge against price increases by participating in the futures market for natural gas. In this market, LDCs can negotiate with producers for supply contracts based on the expected future prices of natural gas. LDCs that previously had to choose between secure but potentially uncompetitive long-term contracts and less secure spot-market purchases can now consider long-term contracts at competitive, futures-based prices, according to the Energy Information Administration (EIA). According to LDC analysts with the National Regulatory Research Institute (NRRI), LDCs have not been very active in the futures market.[4] The analysts reasoned that LDCs may not perceive a price risk for gas supplies because they can pass the variable cost of gas supplies through to their customers under state regulations, as discussed later in this appendix.

Pipeline Transportation Contracts

Under Order 636, LDCs' administrative costs will also increase to contract for transportation capacity with one or more pipeline companies. LDCs will

[3]Under Order 636, the pipeline companies are allowed for the first time to compete with producers and marketers in unregulated sales of gas supplies.

[4]Incentive Regulation for Local Gas Distribution Companies Under Changing Industry Structure, the National Regulatory Research Institute (Columbus, Oh.: Dec. 1991).

contract for capacity with the pipeline company or companies from which they receive direct service. Furthermore, in some cases LDCs may have to contract with several other pipeline companies that are not directly linked with the LDC to arrange delivery of their gas supplies. For example, according to an official representing municipal distributors, Algonquin Gas Transmission Company, an interstate pipeline company located in the Northeast, contracted for capacity on other pipeline companies to transport natural gas from production and storage areas for resale to Algonquin's firm-service customers. According to the official, under Order 636 one of the municipal distributors served by Algonquin will have to sign transportation contracts with four different pipeline companies and a separate storage contract with a fifth pipeline company to receive the same level of storage service that Algonquin had previously provided.

According to officials of a state public utility commission, an LDC, and a consumer advocacy group, LDCs may have to sign firm-service contracts with the pipeline companies for as long as 20 years. FERC did not establish a maximum contract term for firm service. However, under Order 636 LDCs risk losing their firm transportation capacity when their contracts expire unless they match the terms of competitors' bids for capacity for a term of up to 20 years and/or the maximum rate a pipeline company can charge for the service (i.e., the FERC-approved "just and reasonable rate"). A pipeline company can stop service to an LDC at the end of an LDC's contract if a competitor—another LDC, producer, marketer, or large end-user, such as an industrial business—makes a bid for the capacity that the LDC does not match.

According to the officials of a state public utility commission, an LDC, and a consumer advocacy group, contract terms of 20 years deny LDCs the opportunity to take advantage of the competitive market forces that Order 636 is intended to foster and reduce interpipeline competition for firm-service markets. A consumer advocate official explained that LDCs in markets served by more than one pipeline company would like the opportunity to shop for the best transportation rate when their current contracts expire. Under 20-year contracts, LDCs would rarely have this opportunity. Some LDC officials would therefore like to have minimum contract terms ranging from 3 to 10 years. Moreover, according to a state regulator, a 20-year contract has the potential to force LDCs to commit themselves to financial obligations which may, with the passage of time, have disastrous economic consequences. According to a Department of Energy consultant, the 20-year contract term does not further competition in the industry because it limits the ability of LDCs to react to market circumstances. Moreover, the consultant said that SFV rate design reduces the incentives of LDCs to switch to lower-cost pipeline companies during off-peak periods.

FERC says that it will allow the pipeline companies to negotiate contracts with their customers for terms of less than 20 years. However, under FERC's guidelines in Order 636-B, the pipeline company and all its customers must be in agreement in order to have a preapproved, pipeline-wide contract term of less than 20 years for firm service. Because the pipeline companies or certain customers may want long-term contracts for firm service, FERC's guidelines can easily block the efforts of the pipeline companies' other customers with firm service to obtain shorter-term contracts. For example, in approving the compliance plan of a pipeline company, FERC denied the request of all but one firm-service customer of the pipeline company for a shorter-term contract of 5 years. FERC reasoned that because the one customer wanted a long-term contract with the pipeline company, FERC could not approve shorter-term contracts for the other customers. FERC officials said, however, that even without a pipeline-wide contract term of less than 20 years, customers can negotiate with their pipeline companies for shorter-term contracts.

LDCs may also incur additional expenses for pipeline capacity if there is a curtailment in pipeline transportation service caused by force majeure events—such as hurricanes or pipeline ruptures—or by bottlenecks—points on the pipeline that do not have the design characteristics needed to accommodate heavy demand for service—on the system(s) from which they receive service. According to FERC, in the event of such disruptions, an LDC may purchase another LDC's unneeded capacity to obtain its gas supplies. However, an official of a consumer advocacy group said that LDCs served by only one pipeline company will face increased risks of having their capacity curtailed. Such LDCs have no recourse or alternative pipeline company to turn to if a disruption or bottleneck in transportation service occurs on the pipeline system that serves them. Even for LDCs served by multiple pipeline companies, if a disruption occurs during a period of peak demand there may be no capacity available for affected LDCs to purchase.

Storage Facilities

Because of FERC's unbundling of pipeline services, LDCs are now responsible for storing their own gas supplies. In general, two types of storage facilities are used for natural gas: (1) underground storage in a depleted oil field or gas field, an aquifer, or a solution-mined salt cavern, which can store enough gas supplies for sustained peak periods of demand, and (2) above-ground storage tanks for propane, liquified natural gas, and compressed natural gas, which are designed to handle hourly or at most daily spikes in demand and are known as "peak-shaving facilities."[5] Storage facilities are used to balance the relatively constant supply from production regions with the wide seasonal variation in market demand. By storing gas during periods when demand is low and withdrawing it during periods of peak demand, an LDC can effectively manage demand from season to season.

LDCs can either contract for capacity in underground reservoirs owned by interstate pipeline companies, marketers, or independent operators, or build their own storage facilities. According to a National Petroleum Council report,[6] there are about 370 underground storage fields in the United States, with a working capacity of about 4 trillion cubic feet. According to FERC, anticipated new storage facilities are expected to accommodate substantial amounts of natural gas. LDCs own about 167 underground storage fields. However, the average capacity of the facilities owned by LDCs is much smaller than those owned by the interstate pipeline companies.[7]

As discussed in appendix III, LDC officials expect their costs to rise as a result of FERC's change in rate design for pipeline transportation. Many state regulators have recognized the importance of storage as a gas supply management tool to offset demand charges for firm transportation. By contracting for storage services, LDCs may be able to reduce their need for firm pipeline transportation services and lower the overall costs to deliver gas. As also noted, LDCs' transportation rates are influenced by how much they use the pipeline capacity they have contracted for: The higher the utilization, the lower the average charge per mcf of delivered natural gas. LDCs can improve the utilization of their pipeline capacity rights by storing gas in the summer months for use in the winter.

Although storage facilities can be effective tools for LDCs to increase their utilization of pipeline capacity, developing or purchasing underground storage fields is expensive and not feasible in all regions of the country.

[5]The high cost of these facilities and supplies limits their use to the few days per year when consumer demand is highest.

[6]The Potential for Natural Gas in the United States, the National Petroleum Council (Washington, D.C.: Dec. 1992).

[7]Gas Storage: Strategy, Regulation, and Some Competitive Implications, the National Regulatory Research Institute (Columbus, Oh.: Sept. 1990).

According to pipeline company officials, underground storage involves the costs required to (1) develop and install the storage field, (2) buy and inject gas, (3) operate and maintain the facilities, and (4) compress and treat the gas during injection and withdrawal. In addition, certain regions of the country—such as the southeastern states—do not have the natural underground reservoirs that are conducive to storage fields. Thus, LDCs in these regions must either contract for storage in other regions of the country or purchase peak-shaving facilities.

Capacity Release

As noted previously, LDCs can release their unneeded pipeline capacity for resale to others. However, LDCs may require provisions in the contracts for released capacity that specify that the capacity must be restored to the LDC on demand.

According to LDC officials, LDCs' administrative costs will increase as they add staff and computer equipment to monitor releases of their unneeded pipeline capacity reservations through the pipeline companies' electronic bulletin boards. LDCs or other owners of pipeline capacity can release all of their capacity to one purchaser or resell the capacity to multiple purchasers. LDCs are also allowed to make prearranged deals directly with their own end-users for the unneeded capacity rights. However, such arrangements are limited to transactions that are (1) for less than one calendar month or (2) priced at the maximum transportation rate the pipeline company may charge for the service. If the LDC wished to release its unneeded capacity for longer periods of time or at a price less than what it paid the pipeline company, it must make this capacity available to whomever places the highest value on that capacity, up to the maximum rate that FERC allows the pipeline company to charge the LDC.

The pipeline companies will administer the release of LDCs' unneeded capacity through their electronic bulletin boards and may charge LDCs a fee equivalent to the variable cost of this service. The amount of this fee is unknown at this time. Interested buyers, such as industrial businesses, electric utilities, natural gas marketers, and producers, may submit bids for the released capacity. The highest bid that does not exceed the maximum rate a pipeline company can charge wins the capacity.

The pipeline companies must also use the bulletin boards to sell their own excess capacity (capacity they were unable to sell to LDCs or other firm-service customers) on either a firm or interruptible basis. In Order 636, FERC required that pipeline capacity (both firm and interruptible) be made available to compete with released capacity. According to an official of an independent marketing company, a confrontation pitting the pipeline companies' sales of firm and interruptible capacity against LDCs' sale of unneeded pipeline capacity is imminent as the pipeline companies seek to maximize their revenues with additional sales of transportation service and LDCs seek to mitigate their increased costs resulting from demand charges for firm transportation service. According to an industry analyst, the pipeline companies have an economic incentive to sell their excess capacity before that of their LDC customers, while at the same time administering the release of the LDC's unneeded capacity. Therefore, the analyst said, LDCs and others, including FERC, will also need to monitor the electronic bulletin boards to ensure that the pipeline companies do not engage in discriminatory practices.

Management Fees

LDCs' costs could also increase if they pay others to manage their delivery of natural gas supplies. According to LDC analysts with NRRI, entering into new long-term purchase contracts requires an intensive effort in collecting data and analyzing alternatives among potential gas suppliers.[8] There are literally thousands of suppliers with diverse sizes, financial conditions, gas field locations, ownership affiliations, and years of experience in the industry. Many smaller LDCs, particularly municipal distributors, may choose not to purchase their own gas supplies, but may instead pay a marketer, producer, or pipeline company to provide this service. In contrast, medium-sized and large LDCs, which have been buying some of their gas supplies directly since the mid-1980s, may purchase most of their gas supplies, build storage fields, and monitor the release of their unused pipeline capacity.

Natural Gas Marketers

Until LDCs become more experienced with direct gas purchases, LDCs could pay natural gas marketers to find and evaluate gas supplies. Marketers also perform a variety of related services, including arranging pipeline transportation services and monitoring and balancing delivery of gas supplies to ensure that customers receive as much gas from the pipeline system as they injected into the system. In 1992, marketers—both those affiliated with pipeline companies and independent marketers—sold about 51 percent of the gas supplies purchased by LDCs and other customers.[9]

[8]Direct Gas Purchases by Gas Distribution Companies: Supply Reliability and Cost Implications, the National Regulatory Research Institute (Columbus, Oh.: Dec. 1989).

[9]According to FERC, a marketer is considered an affiliate of a pipeline company if the pipeline company owns at least a 10-percent controlling interest in the marketer.

Using a marketer's service could be less costly for an LDC than expending resources on staff and equipment in order to arrange its own gas purchases. According to an official of an independent marketer, natural gas marketers can deliver reliable gas supplies to LDCs at competitive prices. LDC officials told us that they paid marketers a fee of about 5 to 6 cents per mcf for marketing services for firm transportation and 2 to 3 cents per mcf for marketing interruptible transportation services. However, state regulators, LDCs, and municipal distributors are concerned about having to rely on unregulated businesses, whose creditworthiness may be questionable, to obtain gas supplies and release unneeded capacity, particularly since two marketers recently filed for bankruptcy.

Pipeline Company Services

Because some small LDCs and municipal distributors may not have experience in negotiating the purchase of their own gas supplies, FERC will require the pipeline companies to sell them gas supplies at cost for up to a year. Other LDCs can also purchase gas supplies from the pipeline companies, but at market-based prices. In addition, as noted above, LDCs can pay the pipeline companies for a service that enables the distributors to receive gas supplies at any time up to their daily contract entitlement without incurring a penalty. FERC will allow the pipeline companies to enforce operational flow orders that give them the power to direct use of the pipeline system in order to provide this "no notice" service.

Overrun and Imbalance Penalties

LDCs will be liable for penalties assessed by the pipeline companies if they do not operate within the parameters of their daily contracts. If LDCs utilize more firm transportation service than allowed, they will be subject to overrun penalties. If LDCs take more or less gas out of the system than they put in, they will be liable for imbalance penalties. In addition, according to some officials of municipal distributors, because of Order 636 LDCs may also be required to pay damages to their industrial end-users in the event that LDCs incorrectly project the amount of daily pipeline capacity they will need and must curtail services to such end-users. These officials are concerned about the fairness of being charged these imbalance and overrun penalties as they begin to learn how to effectively manage their own gas supplies.

However, the pipeline companies are responsible for maintaining operational control of their pipeline systems to ensure that firm-service customers can use their reserved capacity to receive gas supplies on demand. Central to maintaining operational control is the ability of a pipeline company to manage its customers and prevent them from using more of the pipeline's capacity than the customers' contracts warrant, to the potential disadvantage of other firm-service customers. The pipeline companies plan to impose strict requirements and assess penalties when customers exceed their contracted amount of pipeline capacity.

Municipal Efforts to Mitigate Additional Costs

Municipal distributors in some states may be able to form cooperatives with distributors served by the same pipeline company in other states. For example, distributors in Georgia and Florida have formed cooperatives with distributors in other states served by the same pipeline companies to jointly purchase gas supplies.[10] According to a former FERC Commissioner who was in office during our review, municipal distributors that form cooperatives may, through the aggregation of gas purchases, gain enough purchasing power to lower each LDC's cost of gas supplies. According to an official representing the Georgia distributors, they currently have a long-term gas supply contract at a price below the market price of gas. This official said that municipal distributor cooperatives have more flexibility to take advantage of the new opportunities under Order 636 than the investor-owned LDCs because they do not have to be concerned about prudence reviews by state public utility commissions.

Major Issues Related to the New Services

According to several LDC officials, next to public safety, an LDC's greatest concern is for the reliable delivery of gas supplies. Many state and local authorities and officials representing small LDCs that serve primarily residential end-users are concerned that they will have less reliable gas supplies in the future and yet pay more for these supplies. In addition, state regulators, LDC officials, and LDC analysts with NRRI believe that FERC's rapid implementation of the new regulations, and state public utility commissions' regulatory practices concerning LDC gas supply purchases, may contribute to greater costs for the LDCs.

Supply Reliability

LDCs are concerned about obtaining reliable delivery of natural gas supplies in the future. According to LDC analysts, the reliability of an LDC's gas supply portfolio is determined not only by its procurement decisions but also by the overall market availability of gas and transportation facilities to deliver it. Before Order 636, the pipeline companies had a regulatory obligation to provide LDCs with reliable supplies. Moreover, the pipeline companies were able to aggregate natural gas supplies from a

[10]In Georgia, 56 of the 80 municipal distributors belong to the cooperative.

number of producers in many different production areas. Also, according to LDC analysts with NRRI, while the pipeline companies may have 30 years' experience in finding and evaluating gas suppliers, LDCs have only about 9 years' experience in purchasing just a portion of their gas supply needs.

As previously noted, under Order 636 the pipeline companies are no longer required to sell gas supplies to LDCs. Some LDC officials believe it will be too expensive for them to aggregate gas supplies from several producers or other gas sellers. To the extent that LDCs must rely on fewer gas sellers for their gas supplies, the probability of a supply disruption is greater, according to a consumer advocacy group.

FERC counters that LDCs can ensure reliable delivery of gas supplies by purchasing their gas supplies from different producers on the pipeline system. Order 636 provides LDCs with the flexibility to purchase gas from any producer that has its gas wells physically linked to the pipeline system. Thus, if an LDC experiences problems in obtaining gas supplies from a producer in one area of the country, it may acquire gas supplies from another producer in another area. Also, natural gas marketers, particularly those that have pipelines able to gather supplies in production areas and storage facilities, may be able to provide LDCs with gas supplies as reliable as those the pipeline companies once provided. Officials from FERC, pipeline companies, marketers, and producers believe that LDCs will be able to obtain needed gas supplies at a reasonable price through the menu of services that will open up once Order 636 is implemented. Moreover, as these officials point out, both FERC and the pipeline companies have taken a number of steps to mitigate small LDCs' increased costs.

Transportation Reliability

Officials of LDCs and consumer advocacy groups are also concerned about the possibility of a transportation disruption and about FERC's new policy allowing the pipeline companies to curtail services on a pro rata basis. According to FERC, under Order 636 firm transportation service will be curtailed primarily (if not exclusively) for force majeure events, such as a hurricane, that probably would have led to curtailments in the existing system. FERC contends that disruptions in service caused by bottlenecks should be addressed through contracts. However, an official of a consumer advocacy group counters that end-users see little distinction between curtailment of services caused by a force majeure event and curtailment resulting from excess demand for services on a section of pipeline where capacity is constrained. Moreover, according to officials representing municipal distributors, in Order 636 FERC erroneously interprets the "high priority" end-use provisions of the Natural Gas Policy Act (NGPA), which ensured that residential and commercial end-users would be the last to have their gas supplies curtailed. Officials representing small LDCs and consumer advocacy groups believe that FERC's application of these provisions only to natural gas supplies, not to pipeline transportation, will place such end-users at a greater risk of curtailment.[11] They do not see a distinction between supply reliability and transportation reliability: Unreliable transportation services affects the delivery of gas supplies.

In Order 636-A, FERC stated that its position with respect to high priority users of natural gas has not changed since enactment of the NGPA. Furthermore, FERC maintains that its position is supported by the Natural Gas Wellhead Decontrol Act's policy that a competitive, open-access pipeline transportation system is the best mechanism for ensuring that end-users with no alternatives are not disadvantaged. Thus, FERC decided to require the pipeline companies to develop alternative policies that would curtail transportation services to firm-service customers on an equal or pro rata basis, irrespective of whether the customer was an LDC serving primarily residential and small commercial end-users or an industrial business using gas year-round in its manufacturing process. A federal court recently held that the NGPA is ambiguous as to its application to capacity constraints affecting unbundled transportation service and that FERC's conclusion that the NGPA should not apply to those circumstances is reasonable. However, the court did find that FERC has not sufficiently explained its conclusion that the pipeline companies' plans fulfill the consumer protection requirements of the Natural Gas Act. The court remanded that question to FERC.[12]

According to an official representing major producers, reliable pipeline service is important not only to the pipeline companies, but to all industry segments, including gas producers. The official said that curtailment of service to a customer is a lost sales opportunity for the gas producer. Producers, however, believe that the pipeline companies can provide unbundled services with no loss in service reliability. The official pointed out that in the open-access transportation environment preceding Order 636, the pipeline companies handled thousands of third-party contracts,

[11]In at least one case, FERC has approved a negotiated settlement between a pipeline company and its customers that would ensure that certain high priority end-users, such as schools and hospitals, would not have their firm service curtailed.

[12]City of Mesa v. FERC, 993 F.2d 888 (D.C. Cir. 1993).

which accounted for most of the pipeline companies' transportation volumes. Moreover, the official noted that several pipeline companies were all making successful transitions to an environment in which services were sold separately before Order 636 was issued. However, officials representing municipal distributors countered that the pipeline companies were able to transport large volumes of third-party gas only because the pipeline companies were obligated to provide many of their customers with back-up supplies of gas should problems arise in the third-party contracts.

Rapid Implementation of Order 636

According to LDC officials, FERC's rapid schedule for implementing Order 636 may cause LDCs to incur costs that may have been avoided, and they will pass on these costs to their end-use customers. FERC issued Order 636 on April 8, 1992, and expects the pipeline companies to be in full compliance with the new regulations within 18 months of that date; that is, by the beginning of the 1993-94 winter heating season in November 1993. LDC officials maintain that since the order was issued they have had to attempt to (1) understand the ramifications of the new regulation, (2) meet with pipeline company officials to discuss and negotiate specific issues of concern, (3) comment on the implementation plans filed by their pipeline companies, and (4) negotiate supply contracts with multiple sellers of gas. According to LDC officials, understanding the ramifications of Order 636 for their pipeline companies was a time-consuming task that left little time to negotiate separate contracts for transportation, storage, and gas supply services. Thus, they accepted some contracts that they might not have agreed to if they had had more time to shop among competitors for these services.

In FERC's view, if Order 636 had not been rapidly implemented for all pipeline companies, LDCs might have faced increased costs anyway. For example, LDCs could have been obliged to merge unbundled transportation services from one pipeline company with bundled services from another. In addition, a trade association representing independent producers urged FERC to implement Order 636 as rapidly as possible. The association noted that much of the promise of previous regulatory initiatives was diluted by the decision to work out the details of implementation during pipeline company rate settlements, which sometimes took 3 to 4 years to complete.

State Regulatory Practices

State regulatory practices may not provide LDCs with the incentives they need to minimize these new transaction costs. According to EIA, many states are beginning to require LDCs to submit "least-cost plans" or "integrated resource plans" for review by state commissions. The Energy Policy Act of 1992 required that states consider the use of such plans for regulated gas utilities. Under these plans, LDCs attempt to arrive at the best combination of supply and demand options to serve their end-users at the lowest cost. In the supply-side approach, LDCs focus on (1) management of their gas supply portfolios, stressing a mix of short-, intermediate-, and long-term contracts, and (2) the use of storage capacity and peak-shaving facilities. In contrast, in the demand-side approach, LDCs focus on the consumer's rate of consumption by encouraging more efficient use of the gas supplies.

According to a former FERC Commissioner who was in office at the time of our review, state regulatory practices may hinder or impede the service options that Order 636 will provide to LDCs. An LDC analyst agreed, saying that Order 636 places LDCs at greater risk with no commensurate reward system. From the LDCs' perspective, if they do their best to lower gas supply costs, all of the benefits will go to ratepayers—LDC shareholders will receive none. In addition, the analyst noted that state regulatory practices—such as least-cost plans, for example—could inhibit an LDC's ability to lower ratepayers' costs. He said that least-cost plans work best in relatively stable markets. However, Order 636 is expected to open up the markets, making them more dynamic. Thus, according to this analyst, under a state-preapproved, least-cost plan, an LDC may not be able to change its portfolio of gas supplies in response to changing market opportunities. Moreover, according to the analyst, most state public utility commissions allow LDCs to use a purchased-gas adjustment mechanism to pass on the cost of gas supplies dollar-for-dollar to the end-user. In the view of this analyst, such mechanisms provide LDCs with little incentive to minimize their gas supply costs.

Benefits and Costs of Order 636 and Previous, Related Statutes and Orders

Much of the debate over Order 636 concerns the potential shift in the pipeline companies' fixed costs among LDCs and their end-users. A comprehensive analysis must assess the potential costs and benefits of both Order 636 and previous statutes and FERC orders aimed at promoting a competitive market for the sale of gas supplies. (See app. I for a discussion of the previous statutes and FERC's regulatory changes.) This appendix reviews the available information on the benefits and costs associated with Order 636. We also provide a general discussion and analysis of the benefits and costs resulting from previous statutes and FERC initiatives designed to promote wellhead (i.e., producer) competition and open-access transportation. In both cases, we assess the impacts these initiatives may have had on particular end-users, distributors, pipeline companies, producers, and marketers.

Reliable Estimates of the Benefits or Costs of Order 636 Are Lacking

To examine the potential benefits and costs of Order 636, we reviewed FERC's analysis and planned to use existing natural gas models to estimate the effect of the order on natural gas supply and demand and on factors such as air quality, oil imports, jobs, and industry competitiveness. We found that (1) FERC's estimate of the net benefits was based on a questionable assumption and (2) no existing natural gas simulation model is configured specifically to estimate the potential effects of Order 636 on the natural gas market.

FERC's Analysis of Order 636

To date, FERC is the only organization that has attempted to analyze the potential net benefits to society of Order 636.[1] In its analysis, FERC took others' estimates of increased gas use that were developed without regard to Order 636 and made assumptions about how natural gas prices would react to the resulting changes in the supply and demand relationships. FERC estimated that Order 636 would result in net social benefits of between $2 billion and $6 billion on average per year during the period 1994-2000, for a total net savings of about $15 billion to $42 billion.

The principal criticism of FERC's analysis concerns an assumption used to derive these savings. In developing its estimate, FERC took independent projections of future increases in gas demand (projections that, as noted above, were developed without specific consideration of Order 636) and attributed all the benefits associated with these projections to FERC's new

[1] Costs and Benefits of the Final Restructuring Rule, FERC, Office of Economic Policy, Spring 1992.

rules.[2] Thus, there is little or no relationship between Order 636 and the data used by FERC to calculate its benefits.

Furthermore, FERC's analysis includes only the transition costs associated with new facilities built to implement Order 636. These are the only costs that FERC considered to be new costs to society as a result of the order. FERC did not consider other potential new costs resulting from Order 636, such as the costs LDCs may incur for new services to manage their own gas supplies and transportation. (For a discussion of the transition costs of implementing the new rules and the new service costs to LDCs, see apps. IV and V.) Some of these costs may not have been incurred without Order 636. As a result, these new costs, which FERC excluded, could reduce the benefits of Order 636.[3]

In response to demands from a consumer group for supporting detail, on February 5, 1993, FERC released a technical paper explaining the step-by-step process it used to calculate the benefits reported in its earlier paper.[4] However, the technical paper does not address the principal issue noted above: FERC's benefit estimates are based on projections of increases in gas use that did not consider the effects of the provisions of Order 636.

Existing Models Cannot Project the Changes Resulting From Order 636

Because of the limitations of FERC's analysis, we considered using existing models to develop our own estimate of the net benefits of Order 636. However, after discussions with industry modeling experts, we could not identify a natural gas simulation model that could project the changes in natural gas supply and demand attributable solely to Order 636. In fact, almost all of the natural gas models we reviewed either reflected the structure of the industry before the implementation of open-access

[2]The independent projections were developed by the Department of Energy, Gas Research Institute, American Gas Association, and Enron Pipeline Company, among others.

[3]FERC recognizes that pipeline companies may incur new costs implementing this order; however, FERC does not evaluate any new costs for the LDCs and other pipeline customers. FERC did not discuss the potential net effects of these costs and benefits because it believes the benefits will outweigh the costs.

[4]Costs and Benefits of the Final Restructuring Rule, FERC, Office of Economic Policy, Feb. 5, 1993.

transportation in 1985 or considered other regulatory changes beyond the scope of Order 636.[5]

Industry analysts agree that it is too early to develop a credible model that could simulate the impacts of Order 636. Because Order 636 has not been implemented, no model could adequately depict the new industry structures nor measure what the market prices and quantities of gas sold will be in the new regime. As a result, we could not estimate the net effects of the capacity-release market or other aspects of Order 636 that could mitigate cost-shifts and/or enhance efficiency. Any model estimates of increased gas use would be premised on assumptions about the industry after implementation of Order 636 that may or may not be realized.

Indirect Benefits of Order 636 Cannot Be Quantified

Since there are no estimates of increased gas use attributable to the changes Order 636 will bring, we were unable to project the effect of the new regulations on air quality, oil imports, employment, and U.S. competitiveness. According to industry analysts, even after Order 636 is implemented, modeling the incremental gains in social welfare will be extremely difficult. Such an estimate would require an accurate depiction of the natural gas industry and its interrelationships with other energy markets, as well as the potential effects of changes in energy markets on the macroeconomy and the environment. Moreover, even if these markets and their interrelationships could be modeled accurately, it would be difficult to differentiate among the effects of Order 636, previous related orders, and legislation—such as the Clean Air Act Amendments of 1990 and the Energy Policy Act of 1992—that some believe will have substantial implications for the natural gas industry.

These statutes could contribute to an increased use of natural gas as electric utilities seek to reduce emissions that cause acid rain and purchase additional electricity from gas-fired nonutility generation facilities, and as natural gas is increasingly used as an alternative fuel in motor vehicles. For example, the more stringent emission requirements of the Clean Air Act Amendments of 1990 require a reduction in the amount of sulfur dioxide emitted by electric utilities. In a May 1990 report, we found that some electric utilities would address these requirements by

[5]For example, in the Bush administration's 1992 National Energy Strategy, the Department of Energy (DOE) used its Fossil II model to estimate the changes in energy markets that would accrue from a number of proposed natural gas regulatory reforms, including some that resembled aspects of Order 636. DOE estimated that, beginning in 1995, regulatory changes would increase gas use by 1 trillion cubic feet per year and save consumers about $27 billion in energy costs by 2030. However, these projections of benefits are probably inflated, as some of the regulatory changes proposed in the analysis were not adopted.

injecting natural gas into their boilers to burn with coal (a process known as co-firing) or building new-generation "integrated gasification combined cycle" boilers that are capable of burning either natural gas, oil, or coal.[6] Also, the Energy Policy Act of 1992 amended the Public Utility Holding Company Act to enable electric utilities and nonutilities to build, own, and/or operate wholesale generating plants, and many of these power producers are expected to use natural gas. However, according to the National Petroleum Council, electric utilities have expressed concerns that expected increased gas use by electric utilities may not occur in many regions of the country because of the complexity and cost of buying and transporting natural gas compared with alternative fuels.[7] FERC plans to hold a technical conference to discuss electric utilities' concerns about purchasing and transporting natural gas supplies. In addition, the statutes noted above seek to expand the use of alternative fuels, such as compressed natural gas, in motor vehicles. For example, the Clean Air Act, as amended, requires automobile manufacturers to sell light-duty vehicles that use clean fuels in some parts of the country, and the Energy Policy Act requires the federal government as well as gas utilities and other alternative fuel providers to purchase alternative-fueled vehicles.

Potential Benefits and Costs of Order 636

Although estimates of the potential benefits of Order 636 cannot be reliably projected at this time, the new regulations are nonetheless expected to provide benefits. However, these benefits are likely to have different impacts on the various segments of the industry—end-users, LDCs, pipeline companies, producers, and marketers—and to have associated and sometimes offsetting costs.

Potential Efficiency Gains

FERC contends that the changes resulting from Order 636 could enhance economic efficiency in the natural gas industry. The efficiency gains may be realized through several mechanisms, such as the following:

- Open access transportation. The transformation of the pipeline companies to completely open-access transporters of natural gas will ensure that a pipeline company does not give its own sales or the sales of an affiliate preference over sales by other gas sellers. LDCs and other pipeline company customers will thus be better able to purchase the lowest-cost gas supplies.

[6] Fossil Fuels: Outlook for Utilities' Potential Use of Clean Coal Technologies (GAO/RCED-90-165, May 24, 1990).

[7] The Potential for Natural Gas in the United States, Dec. 1992.

- Unbundling of services. As discussed previously, FERC believes that the unbundling, or separating, of the pipeline companies' sales, transportation, and storage services mandated by Order 636 is necessary to prevent a pipeline company from giving preference to its own gas sales over the sales of other suppliers. Unbundling may also promote efficiency because it allows pipeline customers to buy only the services they desire and to compare prices for individual services.
- SFV rate design. By raising the price to reserve pipeline capacity, SFV rate design could increase the rationing of capacity to those who value it most. However, for reasons discussed in appendix II, whether this change increases efficiency as compared with MFV rate design is subject to debate. FERC believes that SFV rate design will increase the efficiency of the pipeline industry. Reducing the amount of fixed costs included in the commodity charge may encourage greater use of gas and of the pipeline system, particularly by customers with interruptible service. The increased use of gas, in turn, could lower the demand charges for customers with firm service. Also, according to FERC, taking the pipeline companies' fixed costs out of the commodity charge should help create a set of efficient producers offering lower prices that compete in a national market based on their own rather than on the pipeline companies' costs and efficiencies. In turn, this should result in a more constant balance of supply and demand.
- Capacity release market. If the secondary market proves vibrant, it could help ensure that pipeline capacity is held by those who value it most. Flexible prices for capacity may also increase efficiency by promoting use of the pipeline more evenly throughout the year.
- Market centers. Order 636 encourages the development and use of market centers. Market centers are points in the interstate pipeline system where multiple pipeline companies interconnect. FERC believes market centers will facilitate gas purchases between buyers and sellers. Moreover, these market centers may develop into a hub-and-spoke system much like that of the airline industry, where physical swaps of the commodity can occur.

Impact on End-Users

Greater access by end-users, particularly industrial businesses and electric utilities, to producer markets may promote greater competition in those markets and keep the average price of natural gas lower than it would have been without Order 636. In addition, any reduced costs to industrial businesses could be of some indirect value to many residential and commercial customers. According to FERC, reducing the costs to such businesses would reduce the cost of the products they make and enhance their global competitiveness and domestic employment levels. The creation of the capacity release market may also help end-users if LDCs can sell their unneeded capacity and thereby reduce their obligation to pay the higher reservation fees associated with SFV, particularly during off-peak periods.

However, as discussed previously, all end-users may not benefit equally. In particular, benefits to particular residential end-users and other end-users with firm service may be significantly reduced as a result of increased costs passed on to them by their LDCs. These LDCs face (1) cost-shifts resulting from the change in rate design, (2) transition costs, and (3) costs for new services as they take on new responsibilities.

The extent to which these costs could diminish the benefits of Order 636 depends on several factors. These factors include, the success of mitigation measures mandated by FERC and adopted by the pipeline companies, the ability of LDCs to use the capacity release market to reduce their transportation costs, and the way state and local authorities apportion the increased costs to LDCs among their end-users. Because the implementation of Order 636 is not yet complete, the net benefit (or loss) to each customer class cannot be determined at this time.

Some officials of LDCs and a consumer advocacy group believe that Order 636 could also impose costs on end-users if it reduces the reliability of transportation service and gas supplies. As discussed in appendix V, even if LDCs are able to achieve the same level of reliability that they once received from their pipeline companies, this reliability may come at a higher cost.[8]

Other analysts caution that while the Congress has determined that the sale of gas at the wellhead is competitive, the unbundling of services and the creation of open access may allow producers access to essential pipeline and storage facilities that they can use to assert market power at the wellhead. This power, they contend, would be analogous to the pipeline companies' bundled sales service, but with the wellhead price of gas subject to neither regulation nor arms-length bargaining. The Natural Gas Act (NGA), they further contend, is poorly equipped to allow FERC to deal with antitrust matters.

[8]To the degree that these customers may have been subsidized under the previous regulatory structure, these impacts may be warranted. However, as discussed in app. II, determining the existence of cross-subsidization in the natural gas industry is problematic.

Impact on LDCs

Order 636 presents new challenges for LDCs. Greater open-access transportation and the unbundling of pipeline services will allow LDCs to shop for the lowest-priced gas supplies and purchase only the type and amount of services that they require. As discussed previously, according to a state regulator, Order 636 offers the greatest opportunities for medium-sized and larger LDCs, since these LDCs have the sophistication and resources to be active in the spot market, sell unneeded pipeline capacity in the capacity release market, and develop the least-cost transportation networks. These opportunities may also accrue to smaller LDCs and municipal distributors, particularly municipal distributors that are members of a cooperative, but perhaps not to the same degree.

Order 636 also presents new risks for LDCs, as LDCs assume full responsibility for the services that the pipeline companies were formerly required to provide. As noted in appendix V, LDCs may have to pay overrun and imbalance penalties to the pipeline companies if they use more than their contracted amount of transportation capacity and take more or less gas out of the system than their contracts allow. Moreover, the regulatory practices of state and local authorities could play a pivotal role in determining how much risk LDCs can take to maximize the potential benefits of Order 636. (New costs the LDCs may incur and the potential impact of state regulatory practices are discussed in detail in app. V.)

In addition, some officials representing LDCs and industrial end-users, and state regulators believe that smaller LDCs, municipalities, and industrial businesses do not have the sophistication or resources to fulfill their new responsibilities. According to an official representing industrial end-users, even the most sophisticated industrial end-users of gas have at most only two staff procuring gas supplies. These staff also handle other duties and may not have the time or knowledge to monitor available gas supplies and pipeline capacity. However, officials of FERC, pipeline companies, and independent marketers collectively contend that LDCs and industrial end-users do not have to bear such burdens. They believe that smaller LDCs and industrial end-users will be able to contract with natural gas marketers or join cooperatives to obtain the services that were formerly supplied by the pipeline companies. In addition, smaller LDCs can continue to contract with their pipeline company(s) for these services. Critics of these arrangements maintain that even if small LDCs are successful in using marketers or joining cooperatives, they may nonetheless pay more for their gas supplies, transportation, and other services than they did before Order 636.

Officials of LDCs, independent marketers, and electric utilities are concerned that the elimination of FERC's mandatory triennial review of pipeline transportation rates under Order 636 will eliminate the LDCs' only viable mechanism for reviewing the fairness of the pipeline companies' rates. Before Order 636, many pipeline companies used a purchased-gas adjustment mechanism that allowed them to pass on changes in the price of gas supplies dollar-for-dollar to their LDC customers. FERC required the pipeline companies using this mechanism to file for new rates every 3 years so that LDCs and FERC's staff could review the pipeline companies' gas purchasing practices as well as other fixed costs.[9]

According to an official of an independent marketer, the pipeline companies will be able to overrecover fixed costs through their transportation rates because the pipeline companies' utility plant will be depreciating faster than the pipeline companies' rates can be lowered. However, according to an industry financial analyst, mainline pipeline systems are generally depreciated over a 40-to-50 year period. Thus, the amount of fixed costs for depreciation that a pipeline company could overrecover in a given year is a relatively small proportion of total costs that could be depreciated. Moreover, according to a FERC official, if depreciation on capital was the only factor affecting changes in a pipeline companies' cost of service, the pipeline companies could overrecover costs through their rates between rate cases. However, the FERC official said that FERC must consider all factors affecting a pipeline company's cost of service, such as the loss of customers, when it approves changes in the pipeline companies' rates.

According to officials of LDCs and generators of electricity, FERC's mandatory periodic rate reviews provided an important opportunity to participate in the rate-setting process and ensure that the pipeline companies' rates were just and reasonable. FERC maintains that LDCs will continue to have this opportunity when the pipeline companies file for new rates in order to recover the costs of new pipeline facilities.[10] According to FERC, 16 pipeline companies have agreed to file for new rates within a 1-to-2 year period after Order 636 is implemented. However, an official representing municipal distributors points out that these pipeline

[9]According to FERC, the purchased-gas adjustment regulations were adopted in 1972 to curb the frequency of applications for general rate increases and the uncertainty that resulted from administrative delays.

[10]According to a FERC official, however, these reviews will be limited to the rates established to recover the costs of the new facilities. If the costs of a pipeline company's new facilities will be recovered on an incremental basis (i.e., paid for specifically by the customers who will benefit from the new facilities), many of a pipeline company's rates will be omitted from FERC's review.

companies agreed to file for these rates as part of a settlement. In return for the pipeline companies' pledge to file for new rates, the official pointed out that LDCs had to give up something in the settlement agreement.

According to FERC, LDCs will still have the right to challenge whether the pipeline companies' rates are just and reasonable, even without the mandatory triennial rate review. Under section 5 of the NGA, FERC can review a pipeline company's rates to determine whether they are just and reasonable on its own initiative or upon the complaint of a customer, municipality, or state commission.[11]

LDC officials, however, claim that this mechanism is inferior to the periodic rate review because (1) the burden of proof is on the LDC to show that the rates are not just and reasonable, which requires information that only the pipeline companies have access to; (2) these reviews are too costly for them to undertake; (3) FERC, in the past, has not quickly investigated LDCs' challenges of the pipeline companies' rates under this authority; and (4) FERC does not require the pipeline companies to refund the revenues they may have collected through excessive rates. As a result, few challenges have been initiated at FERC under section 5. FERC contends that it will use its powers to the fullest to ensure that the pipeline companies' rates are just and reasonable.

Impact on Pipeline Companies

According to FERC, the most important benefit of FERC's Order 636 for the pipeline companies is the elimination of an asymmetry: Under previous regulations the pipeline companies were obliged to be ready to sell gas to their customers, but the customers were under no obligation to buy the pipeline companies' gas supplies. Order 636 also benefits the pipeline companies by reducing their financial risks through SFV rate design, eliminating the expense and uncertainty of periodic rate reviews, restoring investor confidence, providing additional opportunities to generate revenues, and not requiring them to absorb their prudently incurred transition costs to implement Order 636. SFV rate design reduces the pipeline companies' risk of underrecovering their fixed costs by allocating more of these fixed costs to the demand charge paid by LDCs and other firm-service customers. The pipeline companies will also benefit, as noted

[11]Section 5 of the act expressly authorizes FERC to find whether any "rate, charge, or classification" or "any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential" and requires FERC to determine and fix the "just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed in force." FERC may provide for prospective relief only under section 5 and may not require refunds of any overcharges.

above, by the elimination of the purchased-gas adjustment mechanism, which necessitated a rate review at least every 3 years. According to an industry financial analyst, FERC's rate reviews are long and costly, and can contribute to a great deal of uncertainty in the financial markets. These changes could also restore investor confidence in pipeline company stocks and improve the ability of the pipeline companies to attract investment capital for system expansions in the future. According to the Energy Information Administration, gas use is expected to grow in the industrial and electric utility sectors, producing a need for system expansions.

Under Order 636, the pipeline companies will also be allowed to compete with producers and natural gas marketers for gas sales at unregulated rates. Moreover, the pipeline companies benefit by not having to pay their transition costs to implement the new regulations, as long as these costs are eligible for recovery and prudently incurred. As discussed in appendix IV, these costs could be as much as $4.8 billion.

A primary challenge for the pipeline companies after the implementation of Order 636 will be to ensure that no bottlenecks that could constrain customers' gas supplies arise in the pipeline system. As noted previously, one way the pipeline companies can control the system is by assessing penalties against customers that do not operate within the limits of their transportation contracts.

According to officials representing a pipeline company trade association, the pipeline companies will also be at risk of not recovering (1) all of their costs of terminating or modifying existing gas supply contracts if FERC does not approve these costs during its prudency reviews; (2) their costs for future gas supply contracts; (3) some of the fixed costs that are included in interruptible transportation rates; and (4) their fixed costs in noncompetitive markets, because they may have to negotiate rates with their firm-service customers when the customers' contracts expire.

Impact on Producers

The producer segment of the industry includes both major producers, such as Mobil and Exxon, which are large global companies with publicly traded stocks, and independent producers, which can be either medium-sized companies with publicly traded stocks or small, privately owned companies. Major and independent producers drill for both oil and natural gas reserves. Producers sometimes also discover natural gas reserves, known as associated gas, when drilling for oil. According to an independent producer official, independent producers drill about

85 percent of all domestic wells and produce about 60 percent of the natural gas supplies in this country.

The principal benefit producers expect to realize from Order 636 is access to more buyers of natural gas, particularly in residential markets. According to FERC, during periods of peak demand, producers were disadvantaged vis-a-vis the pipeline companies in selling gas directly to LDCs and end-users, such as industrial businesses and gas-fired electricity generators, because they could not ensure delivery of their gas supplies in all circumstances. Under Order 636, the pipeline companies are required to unbundle and sell their services separately. Therefore, LDCs and end-users will be able to use the firm transportation service they have reserved on the pipelines to transport gas they purchase directly from producers and other gas sellers. Moreover, producers believe that FERC's mandate that the pipeline companies develop user-friendly electronic bulletin boards is a critical step towards achieving equal service for all customers and a more efficient pipeline transportation system.

According to FERC, producers will also benefit from SFV rate design because it does not distort information that the pipeline companies' customers receive about prices as the former MFV rate design did. An association representing independent producers has petitioned FERC for years to implement promised rate reforms that would lower unreasonably high pipeline company transportation rates. The association contends that high transportation rates have resulted in lower net-back prices to producers, causing many to go out of business and placing others in financial distress. According to an official of an independent marketer, SFV rate design will improve the price producers get for their gas supplies because SFV will send clear price signals from the wellhead to LDCs. He said that, as a result, producers will negotiate new long-term contracts that are sensitive to changing market prices and include premiums for reliability and the right of customers to substantially change their hourly or daily consumption of gas (known as "swing rights").

Some LDC officials believe that an objective of Order 636 was to enable producers to increase the cost of their gas supplies. They believe that FERC implemented SFV rate design to remove the pipeline companies' fixed costs from the commodity, or usage, charge so that producers could increase their prices at least up to the price of alternative fuels, such as fuel oil. Officials from producer associations state that such an argument presumes that producers will behave as a cartel, when producers are in fact intensely competitive. According to the Energy Information

Administration (EIA), producers do not have market power when measured by commonly used measures of market concentration.[12] Moreover, FERC points out that, producers will be competing not only with each other for gas sales, but also with pipeline companies and natural gas marketers. However, some industry analysts contend that while producers or other gas sellers may not have nationwide market power, certain gas sellers may have significant market power in particular markets. FERC recognized the potential that certain markets may not be sufficiently competitive in Order 636 and said that it would permit any party in the restructuring proceeding to prove that adequate divertible supplies of gas do not exist with respect to a particular pipeline company. According to FERC officials, no party to the restructuring proceeding claimed that they were unable to obtain competitively priced gas supplies. However, the officials said that if market circumstances were to change and a pipeline company customer could prove it was not able to obtain competitively priced gas from any seller, the Commission could fashion a remedy under the Natural Gas Act, depending on the circumstances of the case.

Impact on Natural Gas Marketers

Natural gas marketers have become a new, important segment of the natural gas industry since the advent of open-access regulations in 1985. In 1992, marketers (either independents or those affiliated with the interstate pipeline companies) arranged transportation for about 51 percent of the natural gas transported by the interstate pipeline companies. Complete unbundling of the pipeline companies' services will benefit marketers by enabling them to compete on equal terms with the pipeline companies for gas sales. As stated previously with respect to producers, in the past marketers could not offer the same quality of service as the pipeline companies because the pipeline companies sold storage and other services as part of a bundled transportation service. Because the pipeline companies must separate their transportation and storage services under Order 636, marketers will potentially be more competitive with the pipeline companies for gas sales.

However, Order 636 may cause a contraction in the number of natural gas marketers. Some industry analysts estimate that by 1992 there were over 300 marketers operating in the industry. According to a marketer official, many of these marketers were individuals managing very small operations. In the future, however, LDCs will be increasingly concerned about the reliability of gas supplies from marketers and the financial viability of

[12]EIA estimated that the Herfindahl-Hirschman index (HHI) for natural gas producers was 129.5 for 1991. Industries with an HHI of less than 1,000 are generally considered to be unconcentrated.

marketers with whom they contract for services. Thus, marketers will have to possess considerable assets in order to (1) gather or acquire supplies from producers and (2) provide storage services.

Benefits and Costs of Previous Statutes and Orders

Legislation and FERC's regulatory changes since 1978 (see app. I) have attempted to introduce market forces in the natural gas industry. The restructuring of the industry brought about by these changes has undoubtedly resulted in benefits, but it has also been difficult and costly, particularly for pipeline companies and producers. However, it is difficult to separate the direct impact of these regulatory changes on the financial health of the industry from (1) the economic impact of a gas supply surplus, which began in 1982; (2) the general decline in the world oil market during the 1980s; and (3) external factors, such as U.S. economic recessions and warm winters, which reduced the demand for natural gas. Moreover, assessing the financial health of the individual segments of the industry—producers, pipeline companies, and LDCs—is complicated by the fact that individual members within these segments are often diverse businesses.

We were unable to find any simulation models that depicted the effect of statutes and FERC orders designed to deregulate the wellhead market and promote open-access transportation. The natural gas models we found simulated the industry before 1985 and thus could not be used to estimate the benefits derived from the initial stages of industry restructuring. No industry experts we interviewed knew of any simulation model that could reliably estimate the effect of recent FERC orders.

According to industry analysts, FERC's previous regulatory changes increased competition in the natural gas industry. However, according to the National Petroleum Council, the dislocations caused by changing regulations have left each segment of the industry scarred in some way and slowed the assimilation of the changes. The associated costs and benefits to each segment of the industry are summarized in general terms below.

Impact on End-Users

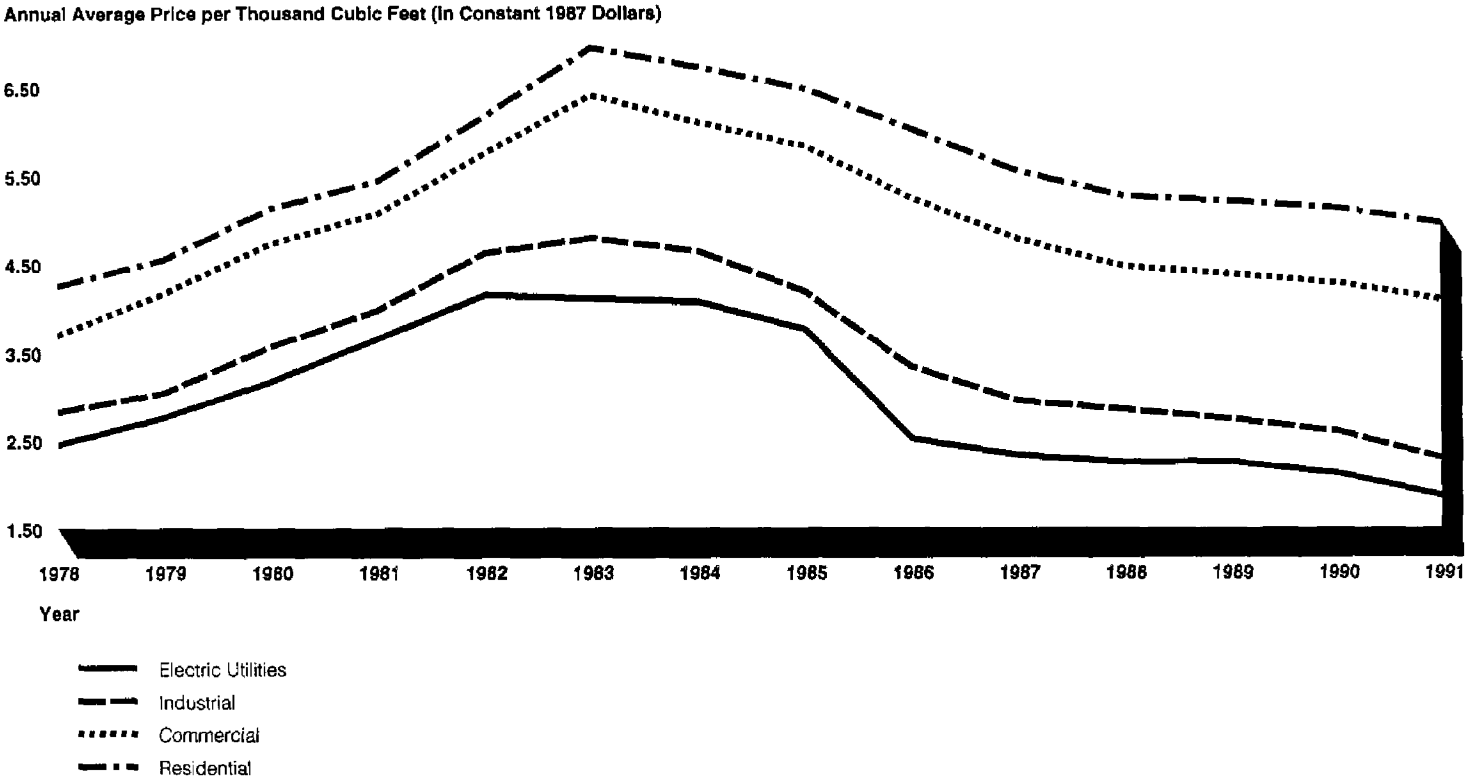
According to EIA, FERC's open-access transportation regulations (Order 436), which enabled LDCs, industrial businesses, and electric utilities to purchase gas directly from the producers, contributed to the drop in end-user prices that occurred between 1984 and 1991.[13]

All end-users benefited from the decrease in prices, although not to the same degree. During the period from 1984 to 1991, average delivered gas prices paid by industrial end-users and electric utilities declined by up to 52 percent, while the decline for residential and commercial end-users was about 29 and 33 percent, respectively.[14] Figure VI.1 shows changes in average delivered prices between 1978 and 1991.

[13]Other factors contributing to lower consumer prices include excess gas supply, unusually warm winters, technological improvements in drilling, tax credits for certain drilling operations, and lower oil prices.

[14]EIA's "delivered gas prices" include gas supply costs, pipeline transportation and storage costs, and LDC distribution and storage costs. However, the delivered price does not include the charges LDCs or end-users paid marketers to purchase gas supplies from producers or arrange pipeline transportation service.

Figure VI.1: Change in Average Delivered Prices to End-Users



Source: GAO illustration based on information from EIA.

According to EIA, in 1991, 28 percent of residential end-users' delivered price of gas was for gas supplies. In contrast, the gas supply costs represented 61 percent and 75 percent of the delivered price to industrial businesses and electric utilities, respectively. Since a larger proportion of the price they pay is for gas, industrial end-users and electric utilities enjoyed a larger decrease in their final charges when gas costs decreased.

FERC's open-access regulations enabled LDCs to purchase less costly gas supplies directly from the producers and, thereby, lower the total cost of gas delivery to the end-users they serve. However, end-users also paid about $6.4 billion of about $10 billion in costs, known as take-or-pay costs, that the pipeline companies paid producers for not purchasing contracted supplies of gas. Moreover, end-users paid other charges, known as gas-inventory-charges, that their LDCs paid the pipeline companies to recover future take-or-pay expenses.

Impact on LDCs

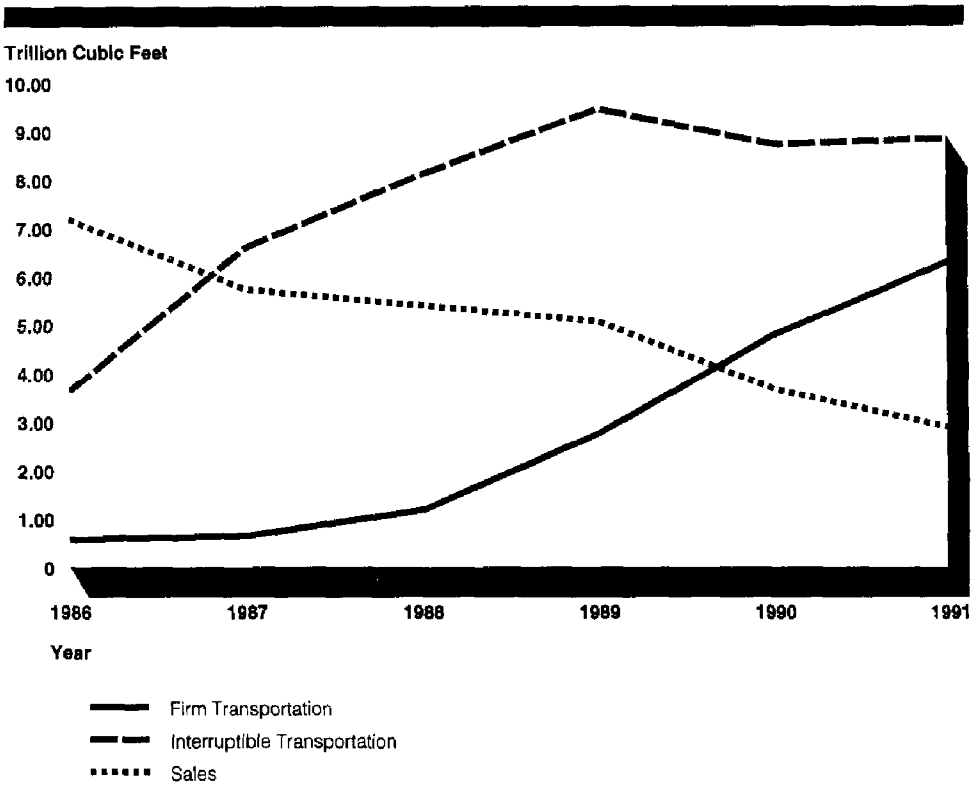
Many LDCs benefited by not having to absorb many of the costs associated with the early period of restructuring that began in 1984 when FERC eliminated the requirement that LDCs purchase a minimum amount of their gas supplies from their pipeline companies. LDCs were able to pass through to their end-users most, if not all, of the resulting take-or-pay costs charged to them by the pipeline companies. However, FERC's open-access regulations have also caused financial concerns for LDCs. FERC's regulations enabled LDCs' large end-users to purchase less costly gas supplies directly from producers. In some cases, industrial end-users physically bypassed their LDCs to hook up directly to a nearby interstate pipeline company. In other cases, LDCs adopted transportation-only rates for large end-users that purchased their own gas supplies and had these supplies transported through the interstate pipeline company and the LDC. When an end-user chooses to bypass an LDC or convert to transportation service, demand-related charges for LDC gas purchases are recovered over a smaller sales volume. These costs include, but are not limited to, take-or-pay costs, interstate pipeline transportation costs, and gas supply management costs. As a result, the end-users still served by the LDC may experience increased costs for delivered gas.

According to an industry financial analyst, however, since 1984 LDCs have had the strongest financial performance of any natural gas industry segment. This analyst said that the average return on equity for large LDCs was 20 percent per year from 1984 to 1992. The analyst also noted that the positive financial picture for LDCs is in stark contrast to their performance in the early 1980s, when Wall Street considered them to be poor investments because it was perceived that the United States was running out of gas. The analyst attributed the LDCs' financial success since the mid-1980s in part to the fact that LDCs were able to pass on to their end-users most of the $6.4 billion in transition costs of implementing FERC's initial open-access regulations, discussed above.

Impact on Pipeline Companies

According to a FERC official, the pipeline companies were arguably the industry segment most adversely affected by previous changes in the industry. Until wellhead price deregulation and open-access transportation began, the pipeline companies had a near monopoly over purchasing natural gas from producers for resale to LDCs and other customers. The monopoly power was greatly eroded by (1) FERC's elimination of the requirement that LDCs purchase a minimum amount of their natural gas supplies from the pipeline companies; (2) FERC's open-access regulations; and (3) the advent of independent natural gas marketers that act as intermediaries between producers, LDCs, industrial businesses, and electric utilities. As shown in Figure VI.2, since 1984 an increasing amount of the natural gas transported through the pipeline system was not owned by the pipeline companies.

Figure VI.2: Changes in Pipeline Companies' Volumes of Gas Supply Sales and Transportation Service



Note: Sales service represents the bundled service—gas supplies, transportation, and storage—that the pipeline companies were previously required to provide to many of their customers.

Source: GAO illustration based on data from the Interstate Natural Gas Association of America.

As LDCs and other customers of the pipeline companies increasingly began to purchase less costly gas supplies directly from the producers under FERC's open-access regulations, the pipeline companies began to incur take-or-pay costs because they could not sell the gas supplies they were contractually obligated to buy from producers. In 1990, FERC determined that the pipeline companies could recover up to 75 percent of their take-or-pay costs from LDCs and other customers.[15] According to FERC, as of July 21, 1993, the pipeline companies or their stockholders had absorbed about 36 percent of the take-or-pay costs, and LDCs' end-users paid the balance, as discussed above.[16] According to an industry financial analyst, these take-or-pay costs contributed to bankruptcy filings by two pipeline companies.

In addition, over the last few years FERC has increasingly placed the pipeline companies at risk of not fully recovering their fixed costs if they did not have firm supply or market contracts when approving new pipeline construction. Moreover, to the extent that the pipeline companies granted customers selective discounts on transportation services, they risked not recovering all of their fixed costs. For these reasons, according to an industry financial analyst, the financial condition of the pipeline industry, as measured by the companies' stock prices, return on equity, and bond ratings, has declined. For example, between 1985 and 1991, pipeline company stock ratings as a group declined from a price index of about 120 to about 110, and bond ratings declined from BBB+ to BBB-. Between 1985 and 1990, the return on equity for the stocks of the same group of pipeline companies declined from about 10.1 percent to about 9.2 percent. An industry financial analyst said that taken together, these stock measures have limited the pipeline companies' ability to attract investment capital and threaten future pipeline system expansions.

On the other hand, according to a study by a major producer association, the pipeline companies maintained relatively high rates of return relative to those earned by the industrial sector as a whole.[17] The producer association used FERC's Form 2 (Annual Report of Major Natural Gas Companies) to conclude that while returns on average common equity for

[15]Order 528 established Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 53 F.E.R.C. ¶ 61,163 (1990).

[16]There is no publicly available information on the costs the producers absorbed in terminating or modifying their gas supply contracts with the pipeline companies. However, according to some producer officials, the producers realized about 20 cents on the dollar when they renegotiated their contracts before they resold the gas supplies.

[17]Financial Performance of Major U.S. Interstate Natural Gas Pipelines: 1981 through 1990, Natural Gas Supply Association (Washington, D.C.: June 1992).

a composite of pipeline companies were significantly lower in 1987 and 1988 because of the companies' take-or-pay expenses, the average return on equity for 1986 through 1990 was almost identical to that of the Standard & Poor's Industrials. A pipeline trade association took issue with this study, claiming that it contained a number of errors. We did not review the study.

According to an industry survey by Salomon Brothers, a private investment firm, the financial health of the industry indicates that the creditworthiness of the pipeline companies has improved since 1992. Moreover, the Salomon Brothers report concluded that the credit ratings of several pipeline companies will be higher in 1993-94 because of (1) higher profits from greater capacity utilization, (2) SFV rates, (3) the issuance of common and preferred stock, and (4) less investment in working capital and capital expenditures. However, investors were also warned of certain financial risks facing the pipeline companies, such as unquantified transition costs.

Impact on Producers

Deregulation of wellhead prices, open-access regulations, and the emergence of market forces that evolved from these actions have undoubtedly put downward pressure on the prices paid to the producers. However, it is difficult to determine the separate effect of these actions from that of other factors, such as the overall supply of and demand for gas, the economy in general, and world prices for oil (a competing fuel). Also, the producers were only partially compensated for the termination or modification of their gas supply contracts with the pipeline companies, required under previous FERC actions. However, the producers were also then free to begin selling their gas in a more open market, with many potential buyers.

According to the National Petroleum Council, even though gas and oil markets function independently, the persistence of excess gas supply and the inevitability that future natural gas discoveries will generally be smaller or deeper and more expensive than discoveries in the past are contributing to a reduction in activity among domestic producers. According to an energy scholar, the domestic oil industry is experiencing a fundamental contraction. Data from the Bureau of Labor Statistics on the number of employees in the domestic oil and gas extraction industries—producers and providers of related services, such as oil and gas well operators and drilling contractors—show that the number of such employees declined by about 354,500, from a record high of about 708,300 in 1982 to 353,800 in 1992. However, when measured from 1977, the year before enactment of the NGPA and the second oil embargo of the 1970s, the number of employees in the industry declined by 27,600, from 381,400 to 353,800. According to an industry analyst, small producers were ripe for a shakeout in an industry that had become bloated during its last boom and has since been gradually deregulated.

Another indication of activity among the producers is their level of exploration, which is driven primarily by current and expected oil and gas prices, according to the National Petroleum Council. There has been a decline in the number of oil and gas drilling rigs, from a high of 3,970 in 1982 to a 40-year low of 860 in 1991. An independent producer official said that this decline can be attributed to several factors, including a general decline in natural gas prices and a lack of price stability in the marketplace due to the prevalence of gas sales in the 30-day spot market, which complicates financial planning. However, a recent survey by Salomon Brothers indicates that independent producers have increased their exploration and production budget by 22 percent in 1993 in light of rising gas prices.

An industry financial analyst notes that it is not economical to drill a gas well if the price for gas is less than $1.50-$2.00 per mcf at the wellhead unless the producer is subsidized by tax credits. Producers receive federal tax credits under section 29 of the Internal Revenue Code for producing gas from nonconventional sources. For example, producers received $0.52 per mcf and $0.90 per mcf in tax credits, respectively, for gas drilled from wells in tightly packed sandstone beds and coal seams through December 31, 1992, and for production from these wells through 2002.

In addition, some U.S. firms, particularly major producers, have found investments in petroleum production more attractive abroad than in the United States, largely because of the decline in the price of oil and favorable geological characteristics in foreign lands, which result in lower discovery and development costs. Moreover, according to the Department of Energy, producers have shifted their exploration activities to other countries in part because tax policies in the United States are less favorable than those of other countries.

Impact on Natural Gas Marketers

As noted above, a major impetus to the increase in the number of natural gas marketers was the implementation of FERC's open-access regulations in 1985. LDCs, industrial businesses, electric utilities, and producers used these intermediary companies to buy and sell gas supplies. According to an official of a large independent marketer, in the first few years after open-access transportation was allowed, marketers realized fairly substantial profit margins (25 to 30 cents per mcf) on their fee for delivered gas. The official said that LDCs were willing to pay this fee because (1) the delivered price of natural gas was still cheaper, even with the markup for the marketers' services, than the delivered price from the pipeline companies and (2) many LDCs were not purchasing their own gas supplies at that time. However, this official said that over time, LDCs became more knowledgeable—even purchasing their own supplies—and would not pay as much for the marketers' services. Today, the official said that marketers' profit margins are substantially lower, generally about 1-5 cents per mcf of delivered natural gas.

Objectives, Scope, and Methodology

The objectives of our review were to (1) estimate the potential shifts in costs among the pipeline companies' customers resulting from the change in the way transportation rates are designed, (2) report the pipeline companies' estimates of the total transition costs involved in implementing Order 636, and (3) summarize available information on the benefits and costs of Order 636 and previous related legislation and orders. To help satisfy the first objective, we employed the services of two consultants, Mr. Robert C. Means, President of USI, Inc., and Mr. Baker G. Clay of Baker G. Clay and Associates. Both Mr. Means and Mr. Clay have worked for FERC or its predecessor regulatory agency—the Federal Power Commission—and represented several segments of the natural gas industry in pipeline company rate cases and other proceedings before FERC and elsewhere.[1]

To accomplish the other two objectives, we reviewed individual pipeline companies' filings with FERC on how they plan to comply with Order 636. In addition, we reviewed academic and trade association literature and interviewed numerous officials representing all major segments of the industry.

The following describes in more detail the methodology we employed.

Estimates of the Nationwide Cost-Shifts

To estimate the nationwide cost-shifts resulting from the switch from the MFV to the SFV method of rate design, we used data on industry costs and the volumes of gas transported from the Energy Information Administration's Statistics of Interstate Natural Gas Pipeline Companies 1990 and the Interstate Natural Gas Association of America, respectively.

We began our analysis by reviewing the nationwide cost-shifts estimated by FERC in Order 636-A. We then devised our own estimates of the industry's cost of service on the basis of the suggestions of our two consultants as well as staff members in FERC's Office of Producer and Pipeline Regulation and Office of Economic Policy.[2] After estimating the cost of service, we allocated the fixed costs of the pipeline companies to

[1]An important consideration in the selection of these consultants was their different views concerning FERC's change in rate design. Mr. Means is on record as favoring adoption of SFV rate design to correct for the competitive disadvantage domestic producers allegedly face when they compete with Canadian producers for gas sales in certain U.S. markets. In contrast, Mr. Clay is on record as opposing the adoption of SFV rate design because it may result in significant cost-shifts to end-users who require firm service. We selected consultants with opposing views on SFV rate design to build in appropriate checks and balances as a guard against any potential bias of the analysis.

[2]Our two consultants independently estimated the total fixed costs for the interstate pipeline industry to be about $9.7 billion and $11.4 billion.

either the commodity (usage) or demand (reservation) charge, according to the MFV method of rate design. Like FERC, we used 1990 statistics for the industry on contract demand or capacity reservations and the volumes of gas transported through the interstate pipeline system. We estimated the amount of the pipeline companies' fixed costs that firm-service customers and interruptible-service customers would pay through the commodity and demand charges under MFV rate design. Using the same methodology, we then estimated the fixed costs that would be paid by firm-service and interruptible-service customers under SFV rate design. The cost-shift represents the transfer in the payment of fixed costs between firm-service and interruptible-service customers resulting from the change in rate design.

As appendix III explains in detail, we performed several analyses to assess the impact of differing assumptions on the ultimate nationwide cost-shift. These assumptions relate to the (1) type of demand charge used to collect the pipeline companies' fixed costs under MFV rate design, (2) discounting of interruptible service, and (3) beneficiaries of interruptible service purchased by LDCS. GAO's "best-case" analysis assumes that, before Order 636, the pipeline companies allocated costs under an MFV rate design with a D-1 charge only, that interruptible service is currently discounted by 10 percent below the FERC-approved rate, and that all interruptible transportation is for the benefit of true interruptible-service customers, i.e., end-users with the ability to switch fuels easily.

Cost-Shifts to Distributors and End-Users

To analyze how LDCS and end-users may be affected by the switch from MFV to SFV rate design, we performed case studies on five judgmentally selected pipeline companies.[3] We chose these pipeline companies because (1) they serve a wide variety of LDCS—large investor-owned utilities as well as small distributors owned by local municipal governments—with varying load factors and (2) the rates and cost structures of these pipeline companies were familiar to our consultants.[4]

Data Sources

We used the following data sources to perform our analysis:

[3]Those pipeline companies were Southern Natural Gas Company, Tennessee Gas Pipeline Company, Texas Gas Transmission Corporation, Transcontinental Gas Pipeline Corporation, and United Gas Pipeline Company.

[4]The five pipeline companies serve LDCs in the Northeast, South, and Midwest.

Pipeline Companies' Data on Rate Design, Fixed Costs, and Volumes

As a starting point of our analysis, we allocated the pipeline companies' fixed costs using the rate design specified in each company's most recent rate filing approved by FERC. For most other information, such as total volumes transported, services, and LDCs served, we used each pipeline company's Order 636 compliance filing to FERC, if FERC had approved it. If FERC had not yet approved the compliance filing, we used the data reported by the pipeline company in its most recent request for new rates filed with FERC.[5] We used the cost-shift estimates of each pipeline company in its compliance filing only if the filing had been approved by FERC.[6]

Data on End-Users

We obtained data on the number of end-users for each LDC from three sources. Initial data were obtained from the 1990 Brown's Directory and from the American Gas Association (AGA). If data on an LDC's end-users were not available from these sources, we called the LDC directly for an estimate of the number of residential, commercial, industrial, and electric utility end-users it serves. We obtained data on the volume of gas consumed and the prices paid by end-users from AGA. AGA also provided GAO with data on the volume of gas sold and transported on behalf of residential, commercial, industrial, and electric utility end-users for each LDC that is an AGA member. For LDCs that are not AGA members, we estimated data on each end-user's consumption using AGA's 1992 Gas Facts. We used table 10-8, "Gas Utility Industry Average Annual Consumption per Customer (End-User) by State and Class of Service, 1991." We then assigned to each end-user the average annual consumption by type of end-user for the state in which the LDC is located. We obtained data on average prices from table 9-6, "Gas Utility Industry Average Prices, by State and Class of Service, 1991." This table provided data on the average price LDCs charged each class of end-user by state. We assigned to each class of end-user the average price for the state in which the LDC is located.

Cost-Shift Scenarios

We could not definitively determine how shifts in costs to each LDC will be passed on to end-users. To estimate the impact, we chose three alternative methods to apportion cost-shifts among residential, commercial, industrial, and electric utility end-users.

- Pro rata method. This method assumes that a shift in costs will be passed on to an end-user in proportion to that end-user's consumption of gas.

[5]The rates stated by a pipeline in its most recent filing are, in effect, subject to refund.

[6]At the time of our review, FERC had rejected several cost-shift studies performed by pipeline companies.

Thus, if residential end-users consume 60 percent of the gas delivered by an LDC, they would pay 60 percent of the costs shifted to that LDC.

Calculating the pro rata shift in costs to each type of end-user involved two steps. First, we calculated the change in each LDC's cost responsibility per unit transported (dekatherm[7]) by dividing the LDC's total change in cost responsibility by the volume of gas that the distributor receives from the interstate pipeline company. We then multiplied the change in cost responsibility per dekatherm by the average annual gas consumption for each type of end-user in order to estimate the cost responsibility for each type of end-user.

- All-to-residential-end-user method. This method assumes that each LDC will allocate all changes in costs resulting from the new rate design directly to its residential end-users. To calculate the cost-shift, we first estimated the total change in the LDC's cost responsibilities for the pipeline companies' fixed costs as a result of the change in rate design. We then divided this change by the estimated total consumption of residential end-users to obtain the change in costs per unit of residential consumption. Finally, we divided this change per unit of residential consumption by the average price for delivered gas paid by a residential end-user (in the state where the LDC is located) to get the average percentage change in costs paid by an LDC's residential end-users as a result of the change in rate design.
- Costs-allocated-as-incurred method. Under this method, we apportioned the pipeline companies' fixed costs as if end-users received gas directly from the pipeline company, without the LDC as an intermediary. In this analysis, we assumed that the average annual consumption by residential end-users would equal 20 percent of an LDC's total annual capacity reservations on a pipeline. Under this scenario, we assumed that public utility commissions pass costs through to end-users as incurred on the basis of the type of service each end-user receives. For example, if all the demand costs charged to an LDC were the result of the distributor's firm service requirements, and residential end-users demanded 90 percent of that firm service, residential end-users would pay 90 percent of the fixed costs charged to the LDC.

  For this allocation method, we first estimated the volume of gas that was delivered by each LDC to its residential end-users, assuming that the residential end-users' total consumption equalled 20 percent of the LDC's

[7]A dekatherm is a measure of the heating value of a fuel. Technically, it equals 10 therms, or 1 million British thermal Units (BTU).

capacity reservations with the pipeline company.[8] Using the estimated residential consumption, we then calculated the pipeline company's fixed costs assigned (via the LDC) to residential end-users under both MFV and SFV rate designs. The difference in the amount of fixed costs assigned represented the total change in costs to residential end-users resulting from the change in rate design.

We then divided this total change in costs by the LDC's total residential consumption to calculate the change in costs to residential end-users per unit of consumption. Finally, we divided the per-unit change in costs to residential end-users by the average price of gas delivery paid by the LDC's residential end-users in order to estimate the percentage change in fixed costs shifted to an LDC's residential end-users as a result of the change in rate design. The cost-shifts to commercial, industrial, and electric utility end-users was then calculated by taking the difference between the total cost-shift to the LDC and the amount of that shift borne by industrial end-users.

Types of Analyses

As explained in appendix III, we calculated two types of cost-shifts in our analysis. For three of the pipeline companies in the analysis, we estimated the shifts in costs resulting from the change in rate design alone. This means that we held all other factors, such as transportation volumes and the number of end-users, constant in calculating the cost responsibilities under MFV and SFV rate designs. For these three pipeline companies, we used the volume and service data reported in their last rate filing with FERC.[9]

For the other two pipeline companies, we estimated the possible combined cost-shifts resulting from the change in rate design and the creation of the capacity release market. As explained in appendix III, FERC staff and representatives of the pipeline industry told GAO they believe that the creation of the capacity release market could significantly reduce the amount of gas that the pipeline companies transport under interruptible service. A significant reduction in the amount of interruptible service could affect the shift in costs to firm-service customers. For this analysis, we calculated the allocation of costs before Order 636 (i.e., under MFV rate design) by using the volumes of firm and interruptible service stated in the

[8] This analysis assumes that all gas delivered to residential consumers by an LDC is transported under firm service.

[9] At the time of our analysis, FERC had not approved the three companies' filings on how they planned to comply with Order 636.

pipeline companies' last rate filings with FERC. However, in calculating the cost allocations based on SFV rate design, we used the volumes of firm and interruptible service projected by each pipeline company after Order 636 is implemented and the capacity release market is created. We obtained these projections from the FERC-approved compliance filings.

Estimates of the Transition Costs

The estimates of the transition costs resulting from Order 636 reported in appendix IV were taken from FERC's July 23, 1993, response to our draft report. FERC derived this estimate by summing the preliminary transition costs reported by each pipeline company in its (1) Order 636 compliance filing or (2) settlements with the company's customers. To learn more about the pipeline companies' estimates of transition costs, we also spoke to officials of the Interstate Natural Gas Association of America (INGAA), Columbia Pipeline Company, and Ohio Consumers Counsel.

Estimates of Increased Gas Bills for Residential End-Users Due to Recovery of Transition Costs

To estimate the transition costs that residential end-users may pay, we first used FERC's July 21, 1993, estimate of total transition costs reported by the pipeline companies ($4.8 billion). From this total, we subtracted $252 million—the estimated cost for new equipment—because these costs will be capitalized or recovered along with other fixed costs through the rates the pipeline companies charge. We then amortized the cost of unpaid gas supplies ($708 million) at a FERC-approved annual interest rate of 6 percent compounded quarterly for 1 year.[10] We amortized the remaining costs ($3.84 billion) for stranded equipment and the realignment (termination or modification) of gas supply contracts at a FERC-approved annual interest rate of 6 percent compounded quarterly for 3 years.[11] Including the costs for amortization, our total estimate of the transition costs that the pipeline companies will recover as a surcharge to the rate for their services is about $5.1 billion.[12]

We estimated the transition costs that residential end-users could pay using two assumptions: (1) that residential end-users will pay the transition costs in proportion to their consumption of gas and (2) that LDCs

[10]We assumed that all of these costs would be recovered in a lump-sum payment at the end of 1 year. However, some of these costs will likely be paid sooner, lowering interest costs.

[11]We assumed that end-users would pay these costs in equal amounts at the end of each year.

[12]In amortizing the transition costs, we did not consider the possibility that residential end-users would lower their consumption of gas in response to higher costs. However, we assumed that the quantity of gas demanded by residential end-users is not very sensitive to higher prices, particularly in the short run.

will allocate all the transition costs to residential end-users. Using the first assumption, we divided our estimate of the total transition costs by the total volume of gas transported by those pipeline companies reporting transition costs (9.95 trillion cubic feet). This calculation gave us the transition costs per thousand cubic feet (mcf). We multiplied this by an AGA estimate of average annual residential consumption of about 100 mcf.

Using the second assumption, we divided our estimate of the total transition costs by the volumes of gas consumed by residential end-users, or about 26 percent of the total volumes of gas transported by those pipeline companies reporting transition costs (9.95 trillion cubic feet). This calculation gave us the transition costs per mcf. We multiplied this by the same AGA estimate of average annual residential consumption (about 100 mcf).

Benefits and Costs of Order 636 and Previous Legislation and Orders

To gather information on the potential benefits and costs of Order 636 and the effects of previous related legislation and orders, we reviewed existing industry and academic literature as well as reports published by FERC, the Energy Information Administration (EIA), the Natural Gas Supply Association (NGSA), INGAA, and the National Regulatory Research Institute (NRRI). We also discussed the applicability of natural gas and environmental models with officials from EIA, the Department of Energy, the Gas Research Institute, and the Environmental Protection Agency, and with several private consultants.

To gain a qualitative understanding of the effects of Order 636 and previous FERC regulatory initiatives, we interviewed FERC's Chair, as well as the former FERC Chairman and the Commissioners who served on the Commission when Order 636 was issued. We spoke to officials of several natural gas trade associations, including AGA, the United Distribution Companies, the American Public Gas Association, INGAA, and NGSA. In addition, we interviewed officials of several LDCs, municipal distributors, the National Association of Utility Consumer Advocates and Citizen Action, the National Association of Regulatory Utility Commissioners, and NRRI as well as other industry analysts. Moreover, we reviewed the comments of these associations, officials, and state regulators on FERC's Order 636. We also spoke to agency officials from FERC, the Department of Energy, and EIA.

Comments From the Federal Energy Regulatory Commission

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIR

July 23, 1993

Mr. Victor S. Rezendes
Director
Energy and Science Issues
United States General Accounting Office
441 G Street, N.W.
Washington, D.C. 20548

Dear Mr. Rezendes:

Thank you for the opportunity to review and comment on the draft report entitled Natural Gas: Costs, Benefits, and Concerns Related to FERC Order 636. The draft report recognizes that Order No. 636 is a significant and useful step in the evolution of a federal regulatory regime that facilitates the development of a fully competitive nationwide natural gas market. A regulatory decision of this magnitude is, by definition, controversial. The report evidences an understanding of a sophisticated industry and a complex regulatory frame work. The effort involved in the report is impressive, and I commend you and your staff for it. I particularly appreciate the objective approach demonstrated by the report.

I note that while identifying uncertainties over ultimate costs and benefits, the draft report makes certain fundamental findings with which I fully agree. The draft report acknowledges that Order No. 636 pursues a valid and important public policy objective--the establishment of an open and competitive natural gas transportation market that allows customers the flexibility to shop for the lowest cost gas supplies. Moreover, the draft report recognizes that although these benefits are as yet difficult to quantify, we may realistically expect that significant customer benefits will result from this program. The findings reaffirm my original support for Order No. 636, and I am confident that our future implementation will be guided by a continued commitment to ensuring that these benefits are realized.

As the report recognizes, about 90 percent of the pipelines' estimated transition costs would have been recovered from customers even absent Order 636. As a result, most transition costs, therefore, are not additional costs on a pipeline system, though some will be allocated differently among customers. The draft report finds that some cost shifts could result in increases to residential customers of up to 9 percent, but acknowledges that these estimates do not take into account the Commission's mitigation requirements which, when applied to specific customers, should substantially reduce, if not eliminate these shifts. The report identifies various techniques that the Commission has used in accomplishing this result.

People may certainly have differing views about various assumptions used in complex economic analyses. I continue to believe that cost impacts due to Order No. 636 will certainly not be as great as some have predicted. I want to reassure those who are worried about increased costs due to the order that the Commission remains absolutely committed to limiting cost shifts due to SFV rate design. We have, indeed, imposed mitigation requirements as recognized in the draft report and will certainly continue to do so in the future. With those mitigation requirements, the cost increases will certainly be limited.

We do have a number of relatively minor concerns about the report. I am enclosing a staff appendix to this letter detailing those concerns. Notwithstanding these concerns, I believe that your report is fair and well-reasoned and confirms my conclusion that Order No. 636 usefully serves its ultimate goal--to use the devices of open access and nationwide competition to provide customers with a reasonably priced and reliable supply of natural gas. This is entirely consistent with our mandate under the Natural Gas Act to protect the public interest. Your report will be useful to us as we continue to evaluate and address the consequences of pipeline restructuring in on-going implementation of Order No. 636. We are looking forward to an opportunity to discuss those concerns with you and the authors of the report at your earliest convenience.

Again, thank you for the opportunity to comment on the draft report. I believe it is responsive to the requests of those who asked GAO to give our program a thorough, independent review.

Best wishes.

Sincerely,

Elizabeth A. Moler

Elizabeth A. Moler
Chair

Enclosure

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Related GAO Products

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