A State Regulatory Strategy for the Transitional Phase of Gas Regulation

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This Article addresses the transitional period of natural gas deregulation under the Federal Energy Regulatory Commission's recently promulgated Order No. 636. Regulation of the natural gas industry is complicated because although production is competitive, transportation and local delivery systems remain monopolistic. Order No. 636 requires gas pipelines to act as common carriers and therefore shifts the locus of regulation to local distribution companies (LDCs). This change means that small customers unable to switch gas suppliers will likely face higher gas costs. Changes in the manner of calculating rates and fuel-switching capabilities by larger purchasers encourages this shift in cost. Additionally, deregulation of gas provision will increase the exposure of LDCs to fluctuations in gas price and availability. This Article proposes that state regulators adopt a system of advanced planning and incentive rate setting. Primarily this involves setting target gas cost ranges for LDCs based on a mix of spot and longer-term contract prices for natural gas and a sharing of gains and losses by the utility and its customers. Using planning, utilities and regulatory commissions can reduce the amount of regulatory risk inherent in the changing environment. By explicitly allowing some risk sharing, state commissions can encourage utilities to take advantage of competitive opportunities in gas commodity markets to the benefit of both large and small gas customers.

Introduction ................................................................. 70

I. Structural and Regulatory Background of Order No. 636 ........ 73
   A. The Industrial Structure of Gas Sales ...................... 73
   B. The Changing Regulatory Structure ....................... 75
   C. The Basics of Order No. 636 ............................. 79
      1. Unbundled Sales and Transportation .................. 79
      2. Encouraging Alternative Gas Sourcing ............... 80
      3. Pricing Firm Transportation Service ................. 80
   D. The Apparent Effects of Order No. 636 on Local Regulation of Natural Gas ....................... 81

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"In your supply contracts, no matter what way you go—if you tie your supplies to indexes, to futures or to fixed prices—something will go wrong. It's just the nature of things."

Introduction

During the 1970s and 1980s, the natural gas market surged from shortage to oversupply as prices fluctuated unpredictably. Industry laid much of the blame for these swings in price and availability upon regulation. Consumers claimed that attempts to control gas pricing saddled them with both gluts and shortages. Likewise, regulation of pipeline and distribution companies met with...
substantial criticism. In response to such criticisms, federal regulators, sometimes with the approval of Congress, began a process of deregulating the natural gas business. The most recent step toward deregulation is the Federal Energy Regulatory Commission’s Order No. 636.

Order No. 636 eliminates the responsibility of interstate pipelines for moving their own gas from the field to the city gate. The Federal Energy Regulatory Commission (FERC) has ordered the pipelines to unbundle and reprice their services so that their customers—mainly local gas distribution companies, municipal authorities, and industrial customers—can package their gas service to include the best-priced combination of gas commodity and transportation. The deregulation methods employed in Order No. 636 are consistent with the basic economic models used in recent years to deregulate other traditional utility services.

Far from removing the regulatory framework from gas sales, Order No. 636 shifts the regulatory focus to the last link in the distribution chain: the state regulated distribution company. Several factors make this shift inevitable. First, mandated change in market structure results in a dramatic shift of costs from customers with choices to those without. Second, the local distribution


9. See infra notes 82-86 and accompanying text.
companies (LDCs) face increased risk in determining gas supplies and securing regulatory approval for those choices. This increased risk will be reflected in higher costs of securing capital, a major component of gas utility rates. In addition to higher costs, LDCs are now more likely to lose industrial customers to competing gas sellers. Finally, the company is likely to have more difficulty providing its basic service: as an LDC increasingly relies on contracting with multiple suppliers in lieu of a single pipeline with a tariffed duty to serve, the LDC runs the risk of incurring the wrath of its state regulator if and when gas providers fail.

In response to these concerns, state regulatory commissions are likely to increase their scrutiny of LDC gas purchasing practices. The tools available to the commissions—prudence reviews, integrated resource planning, and incentive rate setting—are problematic. In particular, some tools provide incentives that are contrary to the goal of benefiting customers with low-cost and reliable service. The alternative, deregulation, is not the answer because portions of the LDC market are not competitive. Given this commercial reality, commissions will have to take some role in regulating the noncompetitive segment of the gas market.

Until it is clear what type of industrial structure will emerge in the distribution of natural gas and whether traditional forms of regulation remain necessary, some form of transitional regulation will be required. Based on the current trends in regulation and policy, it appears likely that a policy will emerge that attempts to provide incentives for LDCs to enter the marketplace aggressively while partially protecting core customers. One approach may employ advanced planning and incentive rate setting. Planning tends to assure both the utility and the commission that reasonable efforts are being made to take advantage of emerging gas opportunities. Incentives provide the utility with the encouragement it may need to undertake the newly-created risks. In addition, the commissions may have to take a critical look at the way that they price interruptible service and transportation rates. The effects of such bypass (such as the direct purchase of gas or the use of alternative fuels), however,


11. See infra notes 89-90 and accompanying text.

12. This jeremiad should not suggest that the changes are all negative. For some customers, new cost saving measures are likely to emerge. Likewise, whole new forms of risk management may appear. Carol Freedenthal, The Gas Industry's Newest Commodity, FORT., Apr. 1, 1994, at 30. For others, however, the transition will be costly, and regulators will have to justify their actions to various political audiences.

13. See discussion infra Part II.C.

Gas Regulation

may not be as significant a problem as the industry’s jeremiads seem to suggest.

This Article explores a potential transitional regulatory scheme based on
the conclusions set out above. The first part briefly explains the structure of
the natural gas industry and its regulation, and notes the changes and new risks
created by Order No. 636 for LDCs and their core customers. Part II reviews
the traditional form of cost regulation used by state commissions to price utility
service and the options state commissions have to address utility management
decisions. This part concludes that the common forms of regulation, by
themselves, do not offer the kinds of protection utility commissions are likely
to find acceptable. Finally, Part III identifies some common assumptions about
the emerging marketplace and proposes a combination of gas purchase planning
and incentive rate making to assure reliable, low-cost service.

I. Structural and Regulatory Background of Order No. 636

The changes directed by Order No. 636 are rooted in both the structure
and the regulation of the gas industry. Transportation and significant portions
of the sales market in the natural gas industry exhibit classic elements of
natural monopoly or oligopoly. This structure leads to the adoption of public
utility regulation. Production of natural gas is, however, potentially
competitive. Attempts to regulate production as if it were a monopoly result
in economic distortions. The industry’s dual nature, monopolistic and
competitive, inspired a rethinking of gas regulation and ultimately Order No.
636.

A. The Industrial Structure of Gas Sales

Both the physical and financial size of the gas industry are impressive.
A 1992 report estimated distribution and transmission facilities at 1.25 million
miles. Total deliveries (sales and transportation) exceeded 15 quadrillion
Btu. In 1991, gas represented approximately one-quarter of total energy
usage in the United States. The plants dedicated to serve that usage were
valued at $129 billion.

There are two other important factors relating to gas usage. First, despite
subsidies historically built into rate structures, the cost of gas delivered to

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16. Id. at 67. Sales constituted nearly 10 quadrillion Btu, with transportation providing the balance. Residential deliveries amounted to 4.7 quadrillion Btu, commercial to 2.2 quadrillion Btu, and industrial to 2.8 quadrillion Btu. Id.
17. Id. at 124.
18. Id. at 153.
residential customers is nominally high relative to the cost to other classes of customers. This translates into a substantial residential revenue base equal to more than half of the utilities’ gross income. Second, even with the substantial and essentially constant industrial use, total gas sales are highly seasonal, with sales increasing dramatically during the winter months.

The business of moving gas from well to user is a multistep process of gathering, transmission, and distribution. The first step entails drilling a productive well and moving the gas to a transmission pipeline through collecting or gathering pipelines. With thousands of producers, this stage of the process is relatively competitive. The cost of gas can, however, vary greatly across regions.

The process of moving gas to the end user is less competitive. Since World War II, transmission of gas has been accomplished through large, high-pressure pipelines that extend for hundreds of miles from gathering areas located primarily in the Southwest to other parts of the country. These capital-intensive businesses tend to serve distinct areas with little head-to-head competition with other gas companies (although there is indirect competition from other sources of energy, such as electricity and oil). The pipeline served as a bottleneck to the sale of gas. Likewise, when the gas neared the end user, a monopoly provider, a LDC, controlled distribution. Authorized by state law, these monopolies laid the last set of lines and pressure facilities that moved

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19. In 1992, the average residential rate for approximately 1,000 cubic feet of gas was $5.69. Commercial customers paid $4.92, and industrial customers paid $2.56. Id. at 107. Note that 1,000 cubic feet = 1 MMBtu.
20. In 1992, residential revenues amounted to $26.7 billion, commercial to $10.9 billion, and industrial to $7.9 billion. Id. at 87.
21. Id. at 72-73.
22. For a simple diagram of the gathering, transmission, and distribution process for natural gas, see VIEITOR, supra note 3, at 102.
23. See PHILLIPS, supra note 2, at 633, 644-45. Hatcher and Tussing state:
   The phased decontrol of wellhead natural gas prices under the [Natural Gas Policy Act] had a profound effect on the industry’s structure. The buying and selling of natural gas as a commodity, distinct from its transportation, became a textbook illustration of near-perfect competition—thousands of buyers and sellers trading a homogenous commodity at prices and according to contract terms that suited their separate needs. This reliance on forces of supply and demand to establish prices, in lieu of government formulas or fiat, was the first of three preconditions for the emergence of a competitive gas procurement sector.
25. Concentration was noted as a problem relatively early in the industrial history of natural gas:
   By 1932 the natural gas industry was concentrated horizontally and vertically. The same four holding companies were the largest four companies in each sector of the business—production, transmission, and distribution. Only the ranking varied . . . . The four-firm concentration in gas production was only 16 percent, but in interstate transmission it was 56 percent, and in distribution, about 60 percent.

VIEITOR, supra note 3, at 98.
the gas to the burnertip. To each community's customers, the transmission of gas, and the purchase of the gas itself, was and remains a monopoly enterprise.\(^{26}\)

Based on the three-tiered transportation structure and the existing scheme of regulation, fixed long-term contracts became a standard feature of gas sales and transportation.\(^{27}\) Both pipelines and LDCs obtained gas through long-term (twenty-year) contracts. Under these contracts, the LDCs agreed to pay for minimum amounts of gas (whether it was transported or not), while the pipelines guaranteed peak amounts (contract requirements).\(^{28}\) This process remained relatively stable until the 1970's when price escalation broke the symmetry of the relationship.\(^{29}\)

B. The Changing Regulatory Structure

Against this mixture of competition and market power, the regulatory scheme developed under a traditional natural monopoly model. The Natural Gas Act\(^{30}\) assigned the Federal Power Commission (now FERC) the responsibility of setting prices for transmission and certain resales of gas. Eventually, jurisdiction was extended to wellhead prices. In time, fundamental problems with gas supplies emerged contemporaneously with significant regulatory problems. In reaction, Congress and the Commission began a process of deregulating the price of gas and separating the gas-merchant function from the gas-transmission function. These steps lead to Order No. 636.

The initial federal regulation, the Natural Gas Act, approached gas regulation as a traditional utility monopoly problem.\(^{31}\) In the traditional model of welfare economics, regulation is justified to correct market failures that lead


\(^{29}\) Id. at 32-33.


\(^{31}\) In the late 1920s, the Federal Trade Commission conducted a study that became the basis for regulation of the gas market. See Vanessa A. Richelle, Reworking Relationships in the Natural Gas Industry: Exploring the New Spot-market and its Operation, 68 Tul. L. REV. 655, 657 (1994). The study identified carriage as the problem and suggested the need for common carriage of natural gas. Congress, however, rejected the common carriage approach and instead adopted a price regulation model similar to that used in the Federal Power Act. Richard J. Pierce, Jr., Reconstituting the Natural Gas Industry from Wellhead to Burnertip, 9 ENERGY L.J. 1, 6 (1988).
to inefficiency. Direct price regulation is often used against monopolies that develop due to scale production factors or specific government decree. In the case of a natural monopoly, the government may intervene to prevent the monopolist from using its market power to raise prices above competitive levels. Such regulation dictates average cost prices to the natural monopolist as a substitute for the market's marginal pricing mechanisms.

The rate-making formula used by commissions to determine the overall revenue to which a utility is entitled is deceptively innocent looking:

\[
\text{Revenue} = \text{Operating Expenses} + (\text{Rate of Return})(\text{Rate base}).
\]

Generally, expenses are the variable costs associated with providing service. These costs include wages, fuel costs, taxes, and depreciation of equipment. Rate base is the capital equipment necessary to provide the required service. Rate of return is the weighted average of the cost of debt and equity necessary to finance utility operations.

Not all equipment owned by the utility can be included in the rate base. First, only equipment used for activities that are related to utility operations is included. Second, commissions will reduce the rate base for the depreciation of equipment. For those items properly included in the rate base there is an additional hurdle: the company must demonstrate that the costs of a capital item were prudently incurred. At issue is the reasonableness of the costs of the investment in the new plant. To the extent that the costs are
Gas Regulation

deemed unreasonable, the investment cannot be included in the rate base of the company and the investors are precluded from earning a return on it.\textsuperscript{43}

Operating expenses are likewise subject to a two-step analysis. First, the expense must be related to the provision of service to customers. Commissions have disallowed a variety of expenses such as excess wages, advertising expenses, and charitable contributions on the belief that these do not contribute to the provision of service to customers.\textsuperscript{44} Second, even if the expense is related to the production of service, the utility may only charge a reasonable cost for it.\textsuperscript{45} In summary, "regulatory agencies retain the authority to exclude costs from allowable revenues where the costs are not reasonably necessary for providing the service . . . and to reduce the amounts requested if they are unreasonable and excessive."\textsuperscript{46}

Initially, the Federal Power Commission regulated only transmission facilities of interstate pipelines.\textsuperscript{47} In 1954, over the Commission's objection,\textsuperscript{48} the Supreme Court extended the jurisdiction of the Commission to include the setting of the wellhead price of gas.\textsuperscript{49} Thus, the Commission began a difficult period of attempting to regulate the gas sales of thousands of gas drillers. Initially, the Commission attempted to price each sale on an individual cost-of-service basis. When this process bogged down due to the sheer volume of the undertaking, the Commission substituted regional and later national pricing rules in an attempt to clear the regulatory gridlock.\textsuperscript{50} Prices, however, lagged behind costs, and shortages developed.\textsuperscript{51} In the 1970s, perceived shortages and general economic malaise led Congress to reevaluate

43. As noted in the basic formula, exclusion from the rate base results in no recovery of a return on that asset. Likewise, a commission will not permit amortization (depreciation expense) of the imprudently incurred costs. \textit{In re Wolf Creek Nuclear Generating Facility}, 70 Pub. Util. Rep. 4th (PUR) 475 (Kan. State Corp. Comm'n 1985), aff'd, Kansas Gas & Elec. Co. v. State Corp. Comm'n, 720 P.2d 1063 (Kan. 1986), vacated in part, 481 U.S. 1044, and appeal dismissed, Kansas City Power & Light Co. v. State Corp. Comm'n, 483 U.S. 1036 (1987). Thus, the total amount deemed imprudent is lost if no further adjustment is made in the rate of return to reflect the increased risk. Commissions are mixed in their treatment of this matter. \textit{Compare id. with Office of Consumers' Counsel v. Utility Comm'n of Ohio}, 437 N.E.2d 586 (Ohio 1982).


45. \textit{Id.}; \textit{see Phillips, supra note 2, at 246}.


47. \textit{Vietor, supra note 3, at 102-03}.

48. \textit{Pierce, supra note 31, at 7-8}.


50. For a discussion of the attempts to adopt pricing structures for gas, \textit{see Permian Basin Area Rate Cases}, 390 U.S. 747 (1969). \textit{See also Pierce, supra note 31, at 8-9}.

the rules for pricing gas. As part of the 1978 energy legislation, Congress adopted the Natural Gas Policy Act (NGPA),52 which over a series of years increased the allowable price for some gas and removed price controls on other gas, depending on the source and time of its discovery.

Partial decontrol of natural gas prices and the recession in the early 1980s turned shortages of gas into surpluses.53 Pipelines that had contracted for gas under the higher NGPA schedules found that the gas was not marketable and began to lose sales from customers with the ability to switch to other fuels.54 Unable to sell contracted-for gas, pipelines sought ways to reopen markets and increase the use of transportation (carriage of gas owned by a third party or a customer rather than the pipeline). Initially, the Commission approved Special Marketing Plans that permitted pipelines to sell gas to fuel switchers at reduced rates.55 This program began to solve pipelines’ problems of gas-surplus purchases, but it failed judicial review.56 In response, the Commission adopted Order No. 436 (and subsequently Order No. 500 in response to judicial remands of the Commission’s rulemaking in Order No. 436)57 to provide mechanisms that allowed the conversion of contract-demand service to transportation.58 In effect, the Commission directed the beginning of unbundling, as customers could now contract separately for gas and transportation.

Despite the significant conversion of supply purchasing to transportation during the initial years of the approach under Order No. 436,59 the Commission concluded that the open transportation dictated by Order No. 436 failed to create an efficient marketplace in gas.60 The Commission concluded that the pipelines’ ability to control access to transportation and its quality resulted in an inefficient reliance on traditional bundled services (even while

53. Duann, supra note 27, at 33. 54. Pierce, supra note 31, at 11. For example, an industrial gas customer might switch from gas to fuel oil.
55. PHILLIPS, supra note 2, at 472 n.91 (collecting cases).
56. Maryland Peoples Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985) (finding Special Marketing Programs unduly discriminatory).
57. See supra note 5 and accompanying text.
58. Broadman and Kalt have noted that the Orders and the then existing environment provided mixed incentives for bypass. On the one hand, the existing fixed contracts and rate structures encouraged bypass. On the other hand, reductions in contract demands and conversions to transportation reduced the need to leave the local distribution system. Broadman & Kalt, supra note 26, at 184-87.
59. Richelle, supra note 31, at 656 n.4 (noting spot-market purchases were approximately forty percent of interstate sales in 1986 and increased to seventy percent in 1988).
60. For the purists advocating deregulation, Order No. 436 fell short in several regards. It did not require pipelines to unbundle their services. More importantly for the courts and pipelines, Order No. 436 failed to address an important asymmetry: Pipelines remained liable to suppliers even while LDCs were being given the opportunity to forgo the purchase of existing contract requirements. For a succinct discussion of the minimum bill and take-or-pay problems caused by commission efforts to address the 1980s downturn in sales, see VIETOR, supra note 3, at 132-61.
Gas Regulation

more and more gas was in fact being transported for end users). The Commission also found evidence that pipelines were discriminating in the quality of service they provided to end users that had migrated to transportation. These findings led to the promulgation of Order No. 636.

C. The Basics of Order No. 636

To rectify the inefficiency created by pipelines' control of service quality, the Commission ordered that pipelines unbundle sales and transportation of gas. Although an LDC could purchase both gas and transportation from a pipeline, gas would be sold separately from the transportation service necessary to move the gas to the end user. Moreover, the commodity price of gas would no longer be set by the Commission. The effect of these changes was to place the responsibility of ensuring gas for the end user on the LDC.

1. Unbundled Sales and Transportation

To avoid discrimination between sales and transportation, Order No. 636 requires pipelines to separate gas sales from transportation. The Order also explicitly sets out a requirement that there should be no undue discrimination in the terms of sales and gas contracts. In an attempt to permit greater flexibility and access to markets, the Order further provided for flexible delivery and receipt points, in other words, gas could be injected into the pipeline and taken from it at varying points according to need. To enhance the available information concerning rates and available capacity, the rule requires pipelines to establish electronic bulletin boards containing rate and other contract information.

61. In its order, the Commission noted that transportation amounted to seventy-nine percent of total gas throughput on the interstate pipelines, but that LDCs had not exercised a similar amount of contract-demand reductions. As a result, LDCs were paying for fixed levels of service but receiving gas subject to conditions of interruptible service. Order No. 636, supra note 6, at 13,272-73. The Commission further noted that transportation was also limited by pipeline restrictions, lack of storage, and lack of access to upstream capacity. Id. at 13,275.

62. Id. at 13,275. The Commission buttressed its decision by finding that pipelines were injured by bundled service requirements and the use of weighted average costing for gas sold under regulation. Under such a pricing scheme, the pipelines could not compete for gas sales to parties who could contract separately for gas purchases. Buyers could purchase gas at lower marginal prices than those available through the pipeline and then contract for the particular level of service they wanted. As a result, buyers could avoid the averaged cost of gas and unwanted premiums associated with service reliability offered by the pipeline.

63. Id. at 13,277.


65. Id. §§ 284.8(b)(2), 284.9(b)(2). See also Order No. 636, supra note 6, at 13,282.

66. 18 C.F.R. § 284.221(g)-(h) (1994).

67. Id. §§ 284.8(b)(3)-284.8(b)(5), 284.9(b)(3)-284.9(b)(5).
A revised view of the market underlies the separation between sales and transportation. In its Orders, the Commission concluded that gas production was sufficiently competitive to permit markets to set pricing for the commodity. Transportation, on the other hand, retained its monopoly status.2

2. Encouraging Alternative Gas Sourcing

To encourage the pipelines' existing firm customers to switch gas sources, the Commission also revised existing contract and tariff obligations. Initially, the Commission directed the conversion of firm rights to gas supplies (contract demand or CD rights) to a right to firm-no-notice transportation. Under this rule, gas purchasers under existing firm-purchase contracts were entitled to the same daily firm amounts of transportation, but the buyers were now responsible for separately assuring that gas needed by their systems was available for transportation. The Commission also ordered that downstream pipelines transfer their capacity rights to upstream pipelines to end users. To the extent that such transportation was not necessary, buyers were permitted to release capacity through pregranted abandonment. Finally, the Commission defined transportation to include storage facilities. The effect of this decision was to make storage a tariffed item available to end users on a nondiscriminatory basis.

3. Pricing Firm Transportation Service

Consistent with other changes that attempted to increase the economic efficiency of pipeline service, the Commission also addressed transportation pricing. Before Order No. 636, the Commission usually assigned some portion of fixed costs to the incremental commodity charge for gas in order to encourage pipelines to seek customers for abundant supplies. Because a fixed cost was added to a variable cost item utilities could only fully recover their fixed costs by using all of their capacity. The Commission found this

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68. Order No. 636-A, supra note 6, at 36,179.
69. Order No. 636, supra note 6, at 13,269.
70. See 18 C.F.R. § 284.8(a)(4) (1994). See also Order No. 636, supra note 6, at 13,287.
71. 18 C.F.R. § 284.242 (1994). See also Order No. 636, supra note 6, at 13,283.
73. 18 C.F.R. § 284.1 (1994).
74. In theory, and probably now in practice, end users could contract for storage so as to purchase gas when prices are low. Then they could hold the gas until it is needed and low-cost supplies are not available. The ability to store, however, is dependent on both storage rights and capacity rights.
75. Order No. 636, supra note 6, at 13,292.
Gas Regulation

pricing scheme inconsistent with the market-based pricing of gas and announced that it would no longer seek to shift fixed costs into the variable cost of gas. Instead, the Commission adopted a straight fixed-variable method for setting transportation rates in which all fixed costs would be assigned to the demand portion of the rate.76 One obvious effect of this change was to shift costs from high-load/low-peak customers (industrial customers) to low-load/high-peak customers (LDCs serving residential customers).77 Another effect was to put more pressure on firm contract holders to reduce the amount of demand charges by reducing firm no-notice transportation claims.

D. The Apparent Effects of Order No. 636 on Local Regulation of Natural Gas

Taken together, the rule changes in Order No. 636 placed a new set of burdens on local distribution companies. As the Commission offered: “It is true that the Commission has changed the terms and conditions of service and thereby subjected pipeline customers to more responsibilities, duties, and risks.”78 That assertion probably understates the result. The LDC, in particular, is now at risk for securing supplies to assure availability, avoiding curtailment of its transportation, and doing all of this at a reasonable cost. The LDC has become a portfolio manager of gas sources, a role unheard of until recently.79

This shift of risk to LDCs comes at the same time as another important regulatory policy. No longer will the doctrine of federal supremacy dictate the pricing of wholesale gas.80 Instead, responsibility for reviewing the LDC's gas costs will shift to the states. As George Hall noted in a similar context: “[Public utility commissions] must confront such issues as whether LDCs are assuming an inappropriate amount of risk or are being sufficiently aggressive

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76. 18 C.F.R. § 284.8(d) (1994); Order No. 636, supra note 6, at 13,270; Order No. 636-A, supra note 6, at 36,173.

77. Order No. 636, supra note 6, at 13,270; Order No. 636-A, supra note 6, at 36,173. LDCs with a high proportion of residential sales face significant problems due to the purchasing patterns of their customers. The cost shift occurs because residential customers tend to buy at defined periods (particularly winter months) when the price of gas is highest and available capacity on a pipeline is at a premium. These peaks must be satisfied by the creation of capacity, a fixed cost. Since fixed costs are no longer shared with interruptible customers, inevitably, capacity costs shift back to remaining firm customers.

78. Order No. 636-B, supra note 6, at 57,912.


80. Extensive literature exists on federal preemption of state rate-making authority. For a listing of these articles and a discussion of the Supreme Court decisions, see Frank P. Darr, Mitigating Costs and the Preemptive Effect of Federal Rate Orders, 13 Energy L.J. 61 (1992). For purposes of this Article, it is assumed that the states will have the authority to review LDC purchasing practices. For the time being, that position is also the one adopted by the FERC. See, e.g., Order No. 636-A, supra note 6, at 36,205.
in seeking bargains. The balancing act will take place within the context of state reviews to determine the appropriate amount of gas costs that should be borne by utility customers.

Several factors make this shift of risk inevitable. First, FERC's change to the straight fixed-variable method of rate setting results in a substantial shift of costs from customers with choices to those without. That is, industrial customers that have access to alternative providers of gas or those that can switch to alternate fuels will face reduced costs while residential and small commercial customers are likely to see higher ones. Second, LDCs face increased risk in determining gas supplies and securing regulatory approval for those choices that will be reflected in higher costs to secure capital, a major component of a gas utility rate case. This increased risk is also likely to be found in a company's ability to provide its basic service: as it relies to a greater extent on contracting with multiple suppliers in place of a single pipeline with a tariffed duty to serve, it incurs the risk that gas providers will fail and that the LDC will incur the wrath of its state regulators for those failures. Indeed, increased regulatory risk, the risk that the markets will perceive a company as being underfunded due to state regulatory action, appears to be one of the dominant concerns arising from Order No. 636.

The combination of higher prices and less reliable service for politically powerful customers will likely lead to a disaster for regulators. At the same time that it becomes more difficult to serve core customers, Order No. 636 creates additional pressures for bypass. Bypass occurs when customers of the LDC turn to another gas provider such as an interstate.

83. Estimates vary as to the amount of redistribution of costs. GAO Issues Final Report on Order No. 636 Economic Impact, FOSTER NAT. GAS REP., Nov. 11, 1993, at 1. The General Accounting Office estimates that the transfer will amount to approximately $1.2 billion annually. RESOURCES, COMMUNITY, & ECONOMIC DEV. DIV., U.S. GEN. ACCOUNTING OFFICE, NATURAL GAS: COSTS, BENEFITS, AND CONCERNS RELATED TO FERC'S ORDER 636, at 2 (1993) [hereinafter GAO REPORT]. In addition, local distribution companies will face new costs associated with acquiring gas that were not necessary under the prior regime. Id. at 4. See also Local Distribution Company Post-Restructuring Issues Are Identified in GAO Report Appendices, FOSTER NAT. GAS REP., Nov. 18, 1993, at 20. Finally, there will be significant one time charges associated with the conversion of existing gas contracts. According to the GAO, new costs associated with transition required under the rule amount to about $300 million. GAO REPORT, supra, at 10.
84. Increased Risk, supra note 10, at 1; Moody's Report, supra note 10, at 7.
86. Craig S. Cano, LDCs Want Market-Based Regulation, but States Need More Convincing, INSIDE F.E.R.C., May 3, 1993, at 7; Phillip S. Cross, Major Issues Remain for States as Order 636 Arrives, FORT., Nov. 1, 1993, at 58; Dodson, supra note 1, at 11.
Gas Regulation

Intrastate, or private pipeline; or start using a fuel other than gas . . . or invest in conservation measures to consume less gas. 87 The problem with bypass is that someone must absorb the share of the gas system's fixed costs that the bypassing customer is no longer paying. 88 Either the remaining customers will absorb these costs, shareholders' returns will decrease, or the company will have to reduce the costs of service, possibly by degrading existing levels of service. 90 As the interstate gas system opened during the 1980s, bypass became an increasing concern because gas producers were willing to sell gas to end users who found pipelines to transport the gas to their facilities. 90 Order No. 636 further encourages bypass by removing existing barriers to transportation and increasing an LDC's cost of purchasing firm gas from a pipeline (by the use of the straight fixed-variable rate methodology). The net effect is to increase the likelihood that the customers with the least economic power will face increased costs. Like the concerns about increased reliability, the bypass problem points to increased state scrutiny.

II. State Action on Order No. 636

While it seems reasonable to assume that state commissions will continue to increase their level of oversight, it is less clear what form this increased oversight will take. Traditional regulation has taken the form of cost-plus pricing and does not fit the emerging environment of partial competition. In addition, both the traditional forms of review and more recent efforts at resource planning and incentive pricing have their own significant problems.

A. The Traditional Structure of Rate Regulation

The existence of natural monopoly-like circumstances in gas distribution implicates the classic rationale for regulation. For at least some core customers, there are few or limited opportunities for alternative sources of gas. 91 Whether driven by the inherent economics of gas provision or the lack of alternative physical facilities, these core customers are locked into a single provider, the LDC. 92 The traditional model of regulation has thus been for

87. Kelly, supra note 26, at 360.
88. Id. For example, if the fixed costs of an LDC are $2 million a year and these are spread over 4 million units of gas, each unit of gas must carry a 50¢ charge per unit for fixed costs. If, for some reason, a large customer leaves the system and the gas sold by the LDC goes to 3.5 million units, the remaining customers will pay a 57¢ charge per unit for fixed costs.
89. Broadman & Kalt, supra note 26, at 203.
90. Kelly, supra note 26, at 360.
91. A distinction is commonly drawn between core and non-core customers. Non-core customers have fuel-switching options.
B. Formal State Actions in Response to Order No. 636

One area of concern involves the transition costs that FERC permitted the pipelines to pass to LDCs.93 Despite FERC's attempt, in its Order, to preempt state review, commissions have sought to address the manner in which costs will be transferred to LDC customers.94 Likewise, some commissions are already attempting to address issues concerning the bypass of LDCs through rate structure reviews.95 These types of claims could well be expected in light of FERC's stated goals in the rule change.

Rate-of-return levels are also ripe for reconsideration. LDCs, for example, are requesting increased rates of return as compensation for the increased risk they face in making supply choices.96 In addition to the rather obvious request for a higher return on equity, there is also the potential for altered debt-equity structure. One Wisconsin utility sought to revise its approved structure so that it could assume additional short-term debt to finance storage costs.97

Much of the transitional work, however, remains to be done.98 For example, states are struggling with the periodic filing requirements for gas purchases to accommodate the new obligations placed on LDCs.99 At least two kinds of problems are likely to emerge. One is the technical treatment of newly identified costs, such as storage, that result from unbundling

93. See supra note 83 and accompanying text.
98. One survey concluded that most states appear to be taking a wait-and-see approach in considering the appropriate regulatory action to Order No. 636. Survey of States Uncovers No Radical Effort to Reform LDC Regulations this Winter, but Ideas for Local Responses to FERC's Restructuring of Natural Gas Pipelines Are Being Explored, FOSTER NAT. GAS REP., Feb. 10, 1994, at 12-20.
Gas Regulation

A second and more important issue is the rule structures and incentives that commissions will adopt in light of the less heavily regulated federal portion of gas sales.101

State commissions are only beginning to look at the long-term regulatory questions. The Massachusetts Department of Public Utilities issued one early decision on the treatment of changes in supply sources. In its decision, the Department concluded that it could not make wholesale changes in its approach to cost recovery, and it would not greatly change its level of review.102 It adopted a two-phase approach. In the first phase, LDCs would seek approval of gas conversions. The conversions would need to be prudent and based on a comparison of available, market-offered replacement resources. Prior approval, however, would not assure the recovery of these gas costs. In the second phase, the Department would continue to review the utility’s management of the resulting gas contracts. Because these contracts would provide the LDCs with the ability to adjust their actual purchases, the Department would continue to monitor those contracts approved in the first phase.

In contrast, the California Commission has embarked on a more aggressive use of incentive regulation of gas procurement. In one case, the Commission announced its intent to tie gas prices to futures prices (with some consideration given to other indices and some given to long-term stability).103 To the extent there was any under- or over-recovery, the approach called for an even distribution of the gains or losses between shareholders and rate payers.104

As the Massachusetts and California opinions suggest, the real battles about the prudence of costs incurred by LDCs are beginning to take place. As the next round of requests for rate increases and purchased-gas adjustment-clause cases begin, the states will be forced to determine whether the LDCs are acting prudently within the new environment.

C. Alternative Regulatory Responses to Order No. 636

State commissions have several tools, such as prudence reviews and resource planning, with which to respond to the changes caused by Order No.

100. Indiana has taken tentative steps to deal with these costs. See, e.g., In re Kokomo Gas & Fuel Co. for Approval of Gas Cost Adjustment, 1993 Ind. PUC LEXIS 228 (June 17, 1993); In re Northern Indiana Pub. Serv. Co. for Approval of Gas Cost Adjustment, Commodity Cost of Gas Adjustment, & Take-Or-Pay Surcharge Adjustment, 1993 Ind. PUC LEXIS 173 (Apr. 30, 1993).


104. Id. at *31-32.
636. Although it appears likely that there will be increased pressure to unbundle services at the local level,\textsuperscript{106} deregulation of all gas service does not appear to be likely. Several factors point to the retention of some form of continued regulation. First, core residential service retains its natural-monopoly characteristics.\textsuperscript{106} Second, there are some practical limits to fuel switching by larger customers.\textsuperscript{107} Finally, there are some painful distributional effects associated with the Order that state regulators are unlikely to ignore.\textsuperscript{108} As a result, LDCs will probably see continued regulation,\textsuperscript{109} and some commentators suggest that the LDCs are likely to see increased levels of regulation in the short-term.\textsuperscript{110}

As noted previously, some state commissions are already studying the problems that the Order has created.\textsuperscript{111} Emerging out of these efforts, and numerous articles and conferences, is a consensus that regulation will move in one of several directions: toward modified prudence reviews, integrated resource planning, or incentive regulation.\textsuperscript{112} Each has its own strengths and weaknesses when judged in light of the policy goals state regulators typically use to explain their actions with regard to an industry in transition.

1. \textit{Regulatory Goals}

Although many criteria are used to measure the appropriateness of a regulatory approach,\textsuperscript{113} three are predominant. First, the approach should make it possible for utilities to attract capital without extracting monopoly profits from customers.\textsuperscript{114} Second, the regulation should have the distributional goal of making the product available to all who need or want it. In this regard, dividing the costs of services becomes important as commissions attempt to subsidize particular classes of users who may not be able to afford

\textsuperscript{105} See supra text accompanying notes 87-89.

\textsuperscript{106} See supra text accompanying notes 25-26.


\textsuperscript{108} The most obvious short-term effect is the recovery of several billion dollars in transition costs. This recovery will be followed by years of potential transfers effected by the adoption of straight-fixed variable rate making. See supra note 83 and accompanying text.

\textsuperscript{109} Cano, supra note 86, at 7.

\textsuperscript{110} Phillip S. Cross, Major Issues Remain for States as Order 636 Arrives, FORT., Nov. 1, 1993, at 58.

\textsuperscript{111} See supra notes 93-100 and accompanying text.

\textsuperscript{112} Regulator: Residentials Will Be on the Short End of Order 636 Benefits, INSIDE F.B.R.C., June 1, 1992, at 6 [hereinafter Regulator].

\textsuperscript{113} Bonbright et al., supra note 34, at 92.

\textsuperscript{114} Id. at 101. This notion of price setting is composed of elements related to capital attraction, efficient production, and consumer rationing. Id. at 92-101. "All three of the functions of public utility rates (based on these rationales) are designed cooperatively to serve one common goal of rate-making policy: the provision of the community with adequate kinds and amounts of public utility service, produced in an economical manner." Id. at 101.
a service level or who have the political wherewithal to claim a preferred allocation.\(^{115}\) Like the telephone industry, where there were significant consumer subsidies built into the system,\(^{116}\) the changes in gas regulation present real threats of unbundling and bypass at the local level that threaten any subsidies in existence.\(^{117}\) Finally, the costs of administering regulation should be reasonable; that is, there should be real benefits to enforcing a particular regulatory regime. It makes no sense to adopt a particular regime if it will not produce benefits—lower prices or lower costs of capital attraction—that outweigh the administrative costs. Thus, there is a practical limit to the amount of tinkering that a commission can and should attempt.\(^{118}\)

Without doubt, there is tension among these goals. To the extent a subsidy exists in a currently approved pricing scheme, it cannot withstand the effects of alternative providers. The subsidy will be bid out of the system.\(^{119}\) On the other hand, it is plainly unfair to allow fuel-switching customers to burden captive customers with the full fixed costs of service. Those core customers’ contributions to fixed costs are a significant reason that fuel switching is available. Finally, it is impossible to assign rates a true cost of service and thus to manipulate the rates to their “efficient” levels.\(^{120}\) There is no simple administrative answer to the problem.

Although no simple formula will relieve the conflict of regulatory goals, one solution might be to adopt only some of the goals.\(^{121}\) Practically, however, no commission can take such an approach because of competing political concerns and the immediate short-term economic transfers that might

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\(^{115}\) Id. at 101-05.

\(^{116}\) See Alfred E. Kahn & William B. Shew, Current Issues in Telecommunications Regulation: Pricing, 4 YALE J. ON REG. 191, 194-95 (1987). Similar concerns arise over the transfers that will occur with the change to straight fixed-variable rate making.

\(^{117}\) Regulator, supra note 112, at 6 ("[T]he past practice often has been to adopt cost- allocation methods ‘because they tend to favor the residential class. Such favoritism toward the residential class may not be possible in the future.’"); see also Larry Foster, Debate on LDC Restructuring Long on Questions, Short on Answers, INSIDE F.E.R.C., May 24, 1993, at 10.

\(^{118}\) The practical limit may be seen by examining the risk of LDC gas procurement error:

It is evident that the risk for the LDC in buying too much or too little commodity gas and transportation capacity or paying too much for gas services always exists. No matter how strict the state oversight is, the risk of making “errors” in gas procurement cannot be totally eliminated. So the objective of state oversight is not to require the LDCs to develop a “perfect” gas procurement strategy but to eliminate any systematic and preventable “errors” or “distortions” that are attributable to the LDCs. In other words, the emphasis of the state commission’s involvement should be to communicate clearly with the LDCs regarding their responsibility and flexibility in arranging gas supplies without the threat of later penalties arising from regulatory hindsight.

Duann, supra note 28, at 74-75.

\(^{119}\) But see infra text accompanying notes 200-01.

\(^{120}\) The problem is intractable because of the existence of common cost for firm and interruptible transportation and commodity service. There is no principled rule to allocate these costs to particular customers. Pierce, supra note 107, at 414.

\(^{121}\) Typical of that approach is Mark Fowler’s controversial position on telephone deregulation. See Fowler et al., supra note 8.
occur. Instead, there must be a balancing of the various interests. The point of accommodation may vary, but it will always exist in some form or another. Because there is no right answer, some process must accommodate the various interests. The current popular ideas are prudence reviews, integrated resource planning, and incentive rate making.

2. Prudence Reviews

Historically, commission practice has been to judge utility costs through a retrospective prudence review. In a prudence review, a commission analyzes a utility's management decisions to determine their reasonableness given the surrounding circumstances. Many states use some form of prudence review.

The strength of the prudence review is that it does not displace the management's ability to make decisions. In its most effective form, the review only examines whether the management decisions and related costs were reasonable under the circumstances. The examination process itself has an important attribute:

Reasonableness reviews reduce an important asymmetry of information that exists between a utility and its regulator. . . . [T]he PUC has enough time to get all the facts it needs to review the reasonableness of a gas utility's supply portfolio. Reasonableness reviews, although generally unpopular, have been effective in catching or preventing large errors made by LDC managers.

As noted previously, it seems likely that utility commissions will continue to use prudence reviews as a means of assuring the public that its welfare is being safeguarded.

122. Order No 636 is remarkable in this regard given the large transfers involved in its implementation. See supra note 83. FERC faced the same kinds of conflicts and modified its introduction of straight fixed-variable rate making, offering small companies alternative rate schedules that broke from the efficiency arguments driving the rest of the order. Order No. 636-A, supra note 6, at 36,173 (rates for small customers subject to volumetric one-part rates).

123. The Illinois Commerce Commission is approaching regulation with a lighter hand, trying to keep "regulatory interference . . . to a minimum." Cano, supra note 86, at 7 (quoting Ruth Kretschmer, Illinois Commerce Commissioner, speaking at the April 1993 Conference sponsored by the National Association of Regulatory Utility Commissioners and the Department of Energy).

124. See supra notes 42-47 and accompanying text.

125. See supra note 28, at 76.

126. Id. at 75 (reporting 31 of 50 states have conducted such reviews).

127. See infra notes 130-133 and accompanying text.


129. Id. at 71-72 ("[R]egulators will be reluctant to remove after-the-fact reasonableness reviews because their regulated utilities that have heretofore been protected and many [utilities] will not have a proven record of operating in competitive gas markets.")
Gas Regulation

There is a significant philosophical and doctrinal limitation on the traditional prudence review. Inherent in the determination that a capital item or an expense is too high is a rejection of the management decision to incur that cost. "If ... consumers prove that utility management was imprudent . . . then imprudent management expenses will be excluded from [the expenses] component of the rate-making formula."130 Such a determination shifts the cost to the utility's investors by moving it out of the revenue formula.131 Thus the reasonableness assessment implies a standard of review of management decision making. The standard of review may vary, depending on the type of expense involved. In the case of expenses for which there is arm’s length bargaining for the item or service, the commission normally gives great deference to management’s choices because the market tends to force the price of the item to competitive levels. On the other hand, commissions will impose a higher level of review in the absence of such bargaining, as in the case of transactions with affiliated companies.132 Even in those situations, however, the courts will require some deference to utility management. The commission must establish that there has been an abuse of discretion and must overcome a presumption of managerial good faith.133 The problem is to determine the degree of deference that ought to be afforded to the utility’s management.

The dichotomy between arm’s length and affiliate transactions, however, does not appear to be particularly pertinent to the emerging state regulation of gas after Order No. 636. If one were to accept the dichotomy, the changes wrought by Order No. 636 would not appear to be significant. In an environment that is likely to be increasingly competitive, the utility’s decisions would seem to be sacrosanct. Only in those instances in which an LDC was purchasing gas from a parent or sister company would the state commission apply a marginally higher level of scrutiny.

The application of the dichotomy is not quite so simple in the Order No. 636 environment. Additional factors must be considered in the prudence review. The Order creates a brand-new world for LDCs. The LDC is not a city-gate purchaser from a source whose prices have already been scrutinized. Their managers are now responsible for creating a portfolio of gas. These decisions bring new kinds of risks. Under these circumstances, it is not clear whether lower levels of review are warranted (given the market checks) or whether higher standards are more appropriate (given the greater levels of risk).

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130. TOMAIN ET AL., supra note 44, at 166.
131. Id.
132. PHILLIPS, supra note 2, at 245.
133. Id. at 246.
Prudence reviews also come with significant costs. First, the process is administratively expensive for both the LDC and the commission. "A prudence review is typically an elaborate and involved process because the state commissions and the LDCs need to reconstruct the market environment upon which the procurement decisions were made initially. It can be a huge undertaking even under the best of circumstances."\(^{134}\) Moreover, as Duann notes, the complexity of the review process can only increase as the number of potential procurement decisions increases with the deregulation of commodity pricing and interstate transportation.\(^{135}\)

Second, the review process may encourage uneconomic choices in both directions. On the one hand, the utility may be too aggressive and lock into short-term contracts to lower prices and thereby increase the risk of a supply disruption.\(^{136}\) On the other hand, the LDC may fear supply disruption so much that it locks in useless long-term contracts and thereby exposes customers to unnecessarily high gas prices for long-term supplies.\(^ {137}\) In either case, the risk of an unfavorable prudence audit would adversely affect the supply mix.\(^ {138}\)

Finally, there is no positive benefit from being aggressive in the traditional prudence review. Because gas costs are an expense, there is a rough dollar for dollar recovery, and the utility gains no particular advantage from an effective cost strategy.

All cost savings from a more efficient fuel portfolio are passed through to ratepayers, if not immediately, then within a short period. Without some positive benefit, utilities will tend to be more passive and cautious in fuel procurement, emphasizing stable (read static) and reliable fuel sources over less costly alternatives, whose substantial price discount may more than offset any disadvantage from lower reliability.\(^{139}\)

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\(^{134}\) Duann, supra note 27, at 76.

\(^{135}\) Id. at 76-77.


\(^{137}\) Increased Risk, supra note 10, at 1 (recognizing both sides of the trade-off).


Part and parcel of this conservatism is the element of regulatory risk itself. "Some analysts have argued that LDCs, in an environment of intense prudence reviews, begin to purchase gas not to meet the overriding goals of reliability, cost, and cost stability, but rather purchase gas in ways defensible in a reasonableness review."140 Taken together, the effects of the regulatory system itself tend to be at odds with each other. It is not remarkable, therefore, that there have been calls for a modified definition of prudence in the new regulatory environment created by Order No. 636.141

3. Integrated Resource Planning

In response to the problems of prudence reviews and to changing regulatory approaches in general, support has grown for prospective reviews of utility purchasing.142 While such planning is in its infancy for gas utilities,143 it has been part of electric utility regulation for several years.144 One estimate suggests that more than thirty states have some form of planning process in place.145 Moreover, the National Energy Policy Act mandates at least the consideration of such an approach for gas utilities by the end of 1994.146 States are beginning formal processes to address that mandate.147

Integrated resource planning (IRP) involves utility management and state commissions in a process of prospectively determining what mix of supply and demand options will produce reliable service at the lowest cost.148 Generally,
the regulatory process will require the LDC to prepare and present an integrated resource plan that explicitly considers supply and demand options. Public participation and either commission review or approval of the plan will follow.\footnote{Goldman ET AL., supra note 128, at 25.}

Like prudence reviews, integrated resource planning has strengths and weaknesses. The primary benefits come from the expectation of better resource planning.

An integrated resource planning process can help facilitate a systematic approach for utility managers to evaluate diverse business activities and potential investments . . . . Gas utilities will increasingly have to offer innovative services to diverse customer groups with varying needs . . . . After completing a strategic planning process, the utility is in a much better position to explain its decision-making and resource procurement process, whether or not it is required to do so by a regulatory commission.\footnote{Pierce, supra note 31, at 51.}

In addition, integrated resource planning would likely reduce the regulatory risk of disallowance that a utility would face without the plan in hand.\footnote{Id. at 28-29. The Ohio commission conceded as much when it adopted its rules for electric company integrated resource planning. In re Revision & Promulgation of Rules for Long-Term Forecast Reports & Integrated Resource Plans of Electric Light Cos., 1989 Ohio PUC LEXIS 1144, at *7 (Oct. 31, 1989) ("[S]ubjectivity in the retrospective analysis of the prudence of management activities will be minimized by the development of a comprehensive record in forecast evaluation proceedings.")}. The assumption is that if the utility commission approves the supply structure of the utility at the outset, it would be less likely to attempt to second guess a LDC.\footnote{Goldman ET AL., supra note 128, at 29-30.}

These benefits, however, come with some likely costs.\footnote{See Goldman ET AL., supra note 128, at 31-32 (forecasting high administrative costs versus low expected benefits, incompatibility with competitive sourcing, and capture of most benefits in building standards).} Most problematic is stagnation which could result from integrated resource planning.

A utility with a commission-approved least or best cost fuel procurement plan is unlikely to deviate greatly from that plan since any deviation places them [sic] at risk of a prudence disallowance. Instead of taking advantage of price differentials among various fuel...
Gas Regulation

markets (for example, gas futures, spot gas, short-term gas, or long-term gas), fuel managers tend to stand firm. The ex-ante fuel procurement review tends to substitute for legitimate managerial prerogatives as the utility adheres to the fuel portfolio approved in the ex ante plan.  

A variation of this problem is the lack of flexibility that the plan may imply. Also, the gains associated with integrated resource planning will not be significant because the practical implications of demand-side management, such as introducing high efficiency water heaters, are not great. Finally, integrated resource planning has the potential to involve high administrative costs. This problem would be particularly visible in early periods of implementation as the companies, the public, and the commissions struggle to determine the unclear definitions associated with integrated resource planning.

Integrated resource planning has some obvious appeal, but shares many of the same problems as prudence reviews. On the one hand, both the commissions and the public would obtain at least a view of the planning process, and access would benefit the company, at least to the extent of

154. Burns & Eifert, supra note 139, at 543.
155. As Duann points out:

The main disadvantage of the prior-review approach is that the procurement plan may be developed and agreed on far ahead of time and the gas market conditions may have changed considerably. By the time the procurement plan is implemented, it is clearly a less desirable plan. Since the LDC's gas procurement decisions will still be evaluated based upon the agreed-upon plan, the LDC will have little incentive to make the necessary adjustments, knowing it will not be penalized for not changing the procurement plan. The implied fixity of an agreed gas procurement plan appears to be counterproductive.

Duann, supra note 28, at 78.

156. As Goldman, et al. elaborate:

Avoided electricity costs often tend to be higher than gas avoided costs when adjusted for equivalent energy service provided. However, it is not that easy to directly compare avoided electric and gas costs because of differences in costing methods and conventions, end-use conversion efficiencies, and operational characteristics of electric and gas utilities. Despite that caveat, avoided gas costs that are lower than avoided electric costs for DSM suggest that: (1) it will be relatively more difficult for gas energy efficiency programs to pass cost-effectiveness tests compared to electric DSM programs, and (2) all else being equal, net DSM program benefits might be smaller.

Goldman et al., supra note 128, at 20-21 (citations omitted); see also David Dodson, Impact of SFV Rates, Transition Costs Overstated, Analysts Argue, Inside F.E.R.C., Nov. 29, 1993, at 11.


158. Parent more fully describes this problem of variation between IRPs of different locations:

IRPs are supposed to take into consideration the costs to society of environmental degradation that are not currently reflected in the price paid for energy at the burner tip or the point-of-use. But the manner of consideration varies widely from state to state, from commission to commission.

reducing regulatory risk. On the other hand, these benefits may not translate into any real financial gains that could not otherwise be obtained by the gas industry through less expensive alternatives such as building codes. Indeed, the benefits may well result in lost opportunities for cost savings through purchasing.

A proposal by Adam Jaffe and Joseph Kalt takes the interesting alternative approach of providing gas purchase planning.\textsuperscript{159} The Jaffe-Kalt method is clearly not a full process of integrated resource planning because it does not adjust for demand-side management. Instead, it looks only at the mix of gas options. "Pre-approval policies would require a gas . . . utility to justify the composition of its acquisition portfolio before the PUC, much the same way that IRP [Integrated Resource Planning] policies now require utilities to justify the extent of their reliance on Demand-Side Management . . . and so forth."\textsuperscript{160} The process would provide a range of options with which the utility could work with some assurance of regulatory approval.\textsuperscript{161}

The approach has two potential advantages. First, it avoids the problem of trying to determine avoided gas costs, a process that appears to have little likelihood of success. Second, it provides the utility with some assurance that its plan, if followed, will result in prudent, and therefore recoverable, expenditures.

4. \textit{Incentive Regulation}

In reaction to the limits of both pre- and post-review of costs in traditional regulation, a growing number of scholars, regulators, and regulated entities argue for some form of incentive regulation. The primary justification for such a change is the information asymmetry that exists between utilities and state commissions. Without a clear sense of how various costs of service fit together, commissions arguably will fail to provide the right cost signals to utilities and their customers.\textsuperscript{162} As a counterbalance to information asymmetries, regulators can attempt to insert incentives in elements of the traditional rate structure or totally divorce prices from costs.

\begin{footnotesize}
\begin{enumerate}
\item \textsuperscript{160} Jaffe & Kalt, \textit{Oversight of Regulated Utilities}, supra note 159, at 123.
\item \textsuperscript{161} Id. Another interesting aspect of the Jaffe-Kalt approach is the use of competitive bidding to fill gas contracts. Id. at 123-24.
\item \textsuperscript{162} Duan, supra note 28 at 80; Mohammad Harunuzzaman et al., \textit{Incentive Regulation for Local Gas Distribution Companies Under Changing Industry Structure}, 91-19 NAT'L REG. RES. INST. 46 (1991).
\end{enumerate}
\end{footnotesize}
a. **Incremental Approaches**

Two common ways of providing incentives involve allowing the utility to retain cost savings or to add additional returns for desired behavior. For example, the commission might set a target rate for gas expenses. If the utility beats that goal, it keeps or shares the benefits of the lower cost. If the utility misses the goal, it absorbs or shares the loss.\(^1\) In this way, the utility's management has an incentive that is consistent with the customers' welfare interest.

One difficulty with such an approach arises in the setting of target prices.\(^2\) One logical construct would use the spot price of gas. Since the spot price represents the current market-clearing price of gas, it is, arguably, the proper measure of value that the utility should be seeking to attain.\(^3\) Regulators, however, are likely to balk at setting prices based on contracts that require only best-efforts production with thirty-day limits.\(^4\) Moreover, price is more volatile than it would be under longer-term agreements.\(^5\) While these short term contracts may be an economic solution, they may not provide the political cover regulators desire.

Another problem with basing incentives on expenses is that it creates problems in calculating the allowable rate of return for the regulated portion of the utility. In the basic formula, rate of return is tied to the rate base, not expenses, and the utility is allowed only a rate of return on rate base. The effect of an incentive structure tied to expenses is that it leverages the rate of return. The extent of the leverage would depend on the ratio of expenses to allowed rate of return and the accuracy of the expense predictions used to set

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3. For an interesting discussion of this point, see Hatcher & Tussing, *supra* note 23, at 21-32. Like Burns and Elfert, they propose a benefit-splitting approach, but their base is tied to a weighted average of spot-market prices. *Id.* at 29.
4. A fine explanation of why regulators will likely hesitate to use only best-efforts production with thirty day limits is explained by Harunuzzaman et al.:
   - It may not be economically optimal to minimize either long-term contract costs or spot-purchase costs individually. This is because the optimal mix depends on demand parameters such as peak demand and annual volume demand, and supply parameters such as the maximum delivery per day each firm supplier can guarantee and the total volume each spot supplier is able to deliver.
   - Harunuzzaman et al., *supra* note 162, at 55. There would appear to be less legal protection against breach as well. Richelle, *supra* note 31, at 666, 676. Hatcher and Tussing, however, point out that spot markets have been more successful in recent years in covering for firm contract shortfall during periods of peak demand. Hatcher & Tussing, *supra* note 23, at 27 n.21.
5. In a discussion of the spot market, Richelle notes that reported spot-market prices moved from $0.95/Mcf to $2.65/Mcf between February and September 1992. Richelle, *supra* note 31, at 662-63. The days of the twenty year contract and its accompanying inefficiencies, however, appear to be gone.
the gas component of retail rate to customers. In any case, rate of return could be greatly exaggerated or injured by the use of an incentive built into expenses. 168

In theory, this leverage problem could be solved by allocating the amount of the savings or loss between the company and its customers. For example, the company and its customers might share equally any loss or gain around the target price for gas. 169 This theory, however, is extraordinarily difficult to apply in practice. Setting the appropriate sharing ratio is hardly a science. Rather, it will reflect a political judgment about the particular level of risk each of the relevant parties should absorb in the newly defined market for natural gas. 170

As a second alternative, the commission might vary the rate of return based on performance. 171 For example, some states have tied the basis points for return on equity to the performance levels of power plants. 172 The clear advantage is the mechanism’s simplicity. Once the standards are set, the commission and utility can mechanically calculate the allowable return. 173 It is not clear, however, that there is any marginal advantage to adopting such a scheme over even simpler options available to the commission.

[I]t can be argued that under flexible rate-of-return pricing the cost-control incentive will not be that much different from the incentive effects of regulatory lag under the traditional rate-of-return regulation. This approach also has apparently no direct effect in adding flexibility for pricing core-distribution service. It is a somewhat compromising approach which may be viewed as a trans-

168. Walker explains:
Disallowances of gas costs can easily wipe out an LDC’s earnings. A review of 1992 fiscal results for the 53-company C.A. Turner Distribution and Integrated Natural Gas Group demonstrates this point. Sixty percent of the group’s revenues were gas costs ($16.6 billion), while income available for common equity was $1.5 billion. A 9-percent disallowance of gas costs would nearly erase the group’s earnings. Conversely, if allowed to keep or share an equal percentage, its earnings would increase dramatically.

169. For an example of the approach using a sharing mechanism, see Harumuzzaman et al., supra note 162, at 63-64.

170. Id. It is also important to note that expense-based incentive programs have been attacked because they have been of limited success. Phillips, supra note 2, at 564 n.156 (citing Eric J. Schneiderwind & Bruce A. Campbell, Michigan Incentive Regulation: The Next Step, in CHALLENGES FOR PUBLIC UTILITY REGULATION IN THE 1980s 407 (Harry M. Trebing ed., 1981)).

171. See generally Harumuzzaman et al., supra note 162, at 77-79.


173. Duann, supra note 28, at 84-85.
Gas Regulation

...ition from the current cost-based regulation to a more “direct” incentive regulation.174

In short, it may be tinkering without any real purpose.

b. Price Caps

In response to the problems associated with incremental changes, a more radical demand for price caps sometimes emerges. This form of incentive regulation seeks to separate pricing from costs by setting a ceiling price and allowing the utility to retain or share the earned profits.175

Under pure [price cap regulation], the earnings of a regulated company are divorced entirely from both its realized production costs and its investment decisions. Maximum average price levels (price caps) are specified in advance and remain unaltered as the magnitude of the company’s realized production costs change or its investment patterns and performance vary. In this respect, the company bears the full financial implications of its actions.176

After a rate hearing of some sort, the incentive rates permitted for particular services would permit the company to recover its costs as initially established. In subsequent periods, the approach would permit increases in rates for exogenous factors such as inflation and taxes. Yet it would encourage the utility to reduce costs by accounting for and offsetting costs against expected increases in productivity.177

There may be several benefits from this form of regulation. First, because every dollar saved is profit for the utility, it creates incentives for utilities to cut costs.178 This incentive would be consistent with the effects of Order No. 636’s requirement of access to competitive gas markets. Second, it avoids

174. Id. at 85.
175. Hantnuzzaman et al., supra note 162, at 46-47.
exposing customers to monopoly rates. The cap prevents that form of expropriation. Finally, administrative costs could be reduced.

Each of these strengths, however, has an elemental problem. First, it is not clear that the incentives would have the intended effects on behavior. Because any really successful program will result in additional state scrutiny to adjust rates to a proper level that does not result in too much return, there is a counter-incentive to take small steps. Second, a successful program may encourage a diminution in the quality of service as the company cuts costs to improve its return under price caps. In the newly deregulated gas market, this change might translate into either inefficient long-term contracts or uncertain short-term arrangements. Third, even though the second argument in favor of caps—that caps avoid gouging—is premised on the belief that the state commission can properly set the rates, the escalators, and the offset, "[t]here are complex problems to be resolved in the implementation of any price-cap regulation. These problems include the selection of the initial price cap, the adjustment indices, the types of services covered, and the period for reconciliation." These problems are especially apparent during periods of price instability. The process of setting and monitoring these sorts of rates is just as complicated as a full-blown rate case, and the public relations problems for a commission that permits a rate that turns out to be too high may be even worse. Thus, while price caps may seem to get the incentives right at one level, the counter-incentives and administrative problems present significant reasons to reject that approach.

III. Dealing with the Future: A Combination Approach

The foregoing discussion of the various ways a commission might pursue the goals of low-cost and efficient administration indicates that no single regulatory or market scheme is a panacea. Rather, each alternative has benefits and costs. The real solution lies in finding the balance of tools and markets.
that best accomplishes those goals at a particular time when the rules are changing and utilities, commissions, and customers are apprehensive.

A. Some Reasonable Assumptions

The proposal that follows is premised on the general goals of utility regulation: avoidance of monopoly pricing; sensitivity to distributional issues; and recognition of administrative costs. Additionally, the proposal rests on several assumptions.

First, reliance on a single regulatory tool or the market is not a workable solution. The various tools, ex ante or post hoc reviews or particular types of incentive regulation, all have inherent problems that make each one standing alone insufficient. In addition, markets are inappropriate remedies because the large core residential customer base is bound to the LDC in what currently appears to be a natural-monopoly relationship. The solution, then, may lie in some combination that draws on providing market-like incentives within the framework of limited regulation.

Second, administrative costs will not be determinative, although the costs may lead to limitations at the margins. Commissions can be expected to continue regulating for the reasons suggested previously. They will continue to use a set of tools, and those tools are costly. Indeed, there is every reason to believe that initially commissions will feel a need to exert more effort just to fill the informational void created by the new rules set out in Order No. 636. While administrative cost at the margins will be important, and the commissions should attempt to adopt a cost-effective mix of tools, deregulation at the federal level will not translate into reduced administrative costs at the state level. In the short term, the opposite is likely to be the case.

Third, commissions will require companies to adopt some sort of mix of long-term, short-term, and spot purchases to satisfy core customer requirements. Although there are arguments to the contrary (and the California commission is experimenting with other alternatives based on spot prices), it seems unlikely that commissions ex ante will find it acceptable for a gas utility to guarantee service on thirty-day spot-market contracts.

Fourth, utility commission will seek to balance monopoly pricing concerns against loss of high-load customers to minimize underuse of facilities (stranded costs) through wider use of transportation programs. Commissions will attempt to keep high-load customers in the system in order to spread demand-related costs. The trade-off for gas utilities is that these high-load customers may be required to absorb more than the incremental price of transportation. That is,
these customers will pay transportation rates that will include costs that might be identified as demand costs that are usually only assignable to firm transportation and commodity customers.

Finally, there are some transaction costs in leaving the LDC and contracting for gas supplies and transportation. These costs include one-time payments required to make a new connection, and the ongoing costs of contracting for gas supplies and transportation. These costs create some cushion in setting transportation rates.

B. A Transitional Approach to Gas Acquisition Reviews

Based on the assumptions set out above, regulation should consist of ex ante planning, incentive rate setting, and post hoc reconciliation. Although administrative costs are potentially high, this approach would tend to lower the uncertainty of review and encourage entry into new markets.

In practice, a commission would establish guidelines to determine the acceptable range of risk represented by varying mixes of spot, short-term, and long-term gas contracts. The commission would then set a target range or dead band of costs for gas. Within that dead band, the commission would estimate gas cost, and set that as the cost of gas to be recovered in rates. The utility could fill its gas needs in the market through whatever means it chooses.

Periodically, annually or semi-annually, the commission would review the rates to determine if the range has been properly set, if the company is making prudent purchasing decisions, and if the company is continuing to earn a reasonable rate of return. During this review, the gas costs would be reviewed to determine compliance with the resource plan. If the utility is within the dead band, there would be no adjustment. If its gas costs are below projected levels, and the company did not unreasonably subject the core customers to unnecessary price risks, it would retain all or a part of the customer receipts, subject to any sharing mechanism the commission might establish. If the utility’s gas costs are above the projected levels, and the company did not purchase gas at unreasonably high rates, it would recover none or a portion of the underpayment from customers, subject to any sharing mechanism the commission might establish.

Because there is a potential for major swings in recovery, the commission would also need to review the rate of return to determine if the company was continuing to earn a reasonable return on rate base. To the extent that the company was over-earning or under-earning, there might be a need to adjust

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190. What follows draws heavily on the literature concerning incentive regulation of gas utilities, in particular the work of Burns & Elfert, Hananuzzaman et al., and Jaffe & Kalt. See supra notes Part II.C.2-C.4.a. The attempt here is to draw the strengths of the various approaches together while eliminating as many of the weaknesses as possible.
Gas Regulation

the formulas used to set gas expenses, to review the distribution between customers and the utility of benefits and losses due to purchasing, or to consider initiating a full review of rates.

For example, assume that a utility needs 200,000 units of gas for customers. It might fill that need through various combinations of contracts. Further assume that through a gas purchase planning hearing, the commission determines that the appropriate range of contracts is between a combination of 30% spot, 30% short-term, and 40% long-term (30-30-40), and a combination of 20% spot, 30% short-term, and 50% long-term (20-30-50). If average prices for these types of contracts at the time of the finding are $1.90, $2.00, and $3.00, then the dead band of rates would be $2.37 to $2.48. Assume the commission sets the price for billing at the midpoint of the range. If the utility's gas costs are within the dead band, there is no disallowance of or additional recovery. If the gas costs are lower than $2.37, the utility would either retain or partially retain receipts based on the average price. In that case, however, the commission would determine whether the company incurred an unreasonable amount of risk. If the gas utility did not incur unreasonable risks, the commission should allow the pass through of receipts to the utility to continue. For the next period, however, the commission might want to consider making an adjustment to the formula for calculating the dead band. If the gas cost savings are attributable to a different mix of contracts, the commission should consider revising the formula to reflect more

<table>
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<tr>
<th></th>
<th>Spot (%)</th>
<th>Short (%)</th>
<th>Long (%)</th>
<th>Total Cost</th>
<th>Ave. Cost</th>
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</thead>
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<tr>
<td>High Risk</td>
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<td>$120,000</td>
<td>$240,000</td>
<td>$474,000</td>
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<td></td>
<td>(.3)</td>
<td>(.3)</td>
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<tr>
<td></td>
<td>($1.90)</td>
<td>($2.00)</td>
<td>($3.00)</td>
<td></td>
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<tr>
<td>Low Risk</td>
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<td>$300,000</td>
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The figure in each block indicates the percentage of that particular component assigned by the commission. To calculate properly the weighted average of the total, the component totals are calculated, summed (TC), and divided by the total number of units.

191. The calculations are set out below:

192. Under this circumstance, the recalculation should only occur if there were an expectation of continued low rates.
clearly the market risks that appear reasonable under changing circumstances. If the utility acted unreasonably in incurring the savings, then the response should be a full or total refund of the savings to customers.\textsuperscript{193}

If the gas costs exceed those projected by the dead band, the utility would be liable for all or part of the excess costs. If the utility was reasonable in incurring these costs, then the predetermined recovery mechanism should be applied. As in the prior example, the commission should determine whether the preexisting price assumptions and mix ratios should be adjusted. If the commission determines that the overage is the result of imprudent behavior, however, then the loss should fall on the utility.

This proposal meets the criteria for setting the incentives in a manner that is consistent for both sides of the transaction. The utility has an opportunity to take advantage of the marketplace and retain some of the benefits of its managerial efforts. The commission will not have to bailout the utility for its mistakes or foreclose the possibility that existing practices cannot be improved and then passed through to customers. The proposal will encourage least-cost purchasing and simultaneously assure the commission that the utility is not taking advantage of the risk presented by some forms of incentive regulation.

It is unclear, however, whether this incentive form of regulation has the ability to avoid the problems and disincentives associated with a commission’s reversal. Part of the problem may be avoided by adding a requirement that the utility competitively bid its requirements under the formula.\textsuperscript{194} Bidding might have the effect of assuring regulators that the gas purchases made were the best available for a given level of reliability. Thus, the regulators would have less incentive to reverse or recontract prior determinations. Formal auctions, however, carry their own costs, and it is not clear that the costs are justified.\textsuperscript{195} If the incentives cannot be built into the process by some sort of external factor, then it will fall on the state commission to regulate in good faith and avoid the recontracting problems on its own initiative.

A second problem is that commission review will require substantial administrative resources. To create confidence in the end product, the commission will be reviewing a broader range of purchasing activities. Despite increased administrative costs and resources, the apparent trend in regulation points in this direction. The alternatives to setting core customer rates—increased prudence reviews, price caps, or deregulation—are not

\textsuperscript{193} To the extent that the utility stayed within the ranges and took advantage of lower prices, those lower prices should be reflected in the new calculation of the dead band. This aspect of the proposal is problematic since it creates an incentive for the commission to disallow costs. Commissions have often been attacked for their abuse of this power. Richard J. Pierce, Jr., \textit{Public Utility Regulatory Takings: Should the Judiciary Attempt to Police the Political Institutions?}, 77 GEO. L.J. 2031, 2047-53 (1989).

\textsuperscript{194} Jaffe & Kalt, \textit{Oversights of Regulated Utilities}, supra note 160, at 123-24 (proposing mandating LDCs to seek competitive bids for gas resources).

\textsuperscript{195} Electronic bulletin board systems may be one way to reduce auction costs.

102
Gas Regulation

particularly palatable. Moreover, to the extent that the proposed formula works, the review process would be simplified over time as the informational problems decrease with experience. More importantly, the proposal looks at gas costs, the most significant and variable item in the customer bill. It logically follows that the commission should focus its resources on assuring itself and the public that the utility is making reasonable efforts to address the new marketplace and take advantage of available benefits.

C. The Problem of Bypass

The commission will face both renewed claims of bypass and the need to address transportation access and rates. Some level of unbundling would appear to be a foregone conclusion. The marketplace requires a response that includes transportation. Most states already permit such inclusion and Order No. 636 will further encourage such actions on the part of customers that have the means to purchase gas. The real debate will be on setting transportation rates that will allow LDCs to retain some of the load. That debate will turn on whether the transportation rate should include a portion of the system’s fixed costs for what would appear to be interruptible service. As more costs are included, the transportation rate will tend to encourage bypass; as rates are lowered, the utility will face an ever tighter cost squeeze that will have to be made up somewhere else.

Although it is clear that price discrimination cannot be sustained, it is not self-evident that all fuel-switching customers will leave the system in significant numbers or that the core customers absorb all of the costs of bypass. One element that is seldom included in the calculation, however, is the transaction costs that a transporter must incur to leave the system. First, there is the cost of leaving the system and making any necessary new connections to a pipeline. Second, and more important, are the costs of contracting for a predictable level of service. The transporter either will have to develop that expertise internally or contract for it. Recognition of this cost may give commissions some room to shift costs in the short term to those high-

196. Harunuzzaman et al., supra note 162, at 55.
197. Broadman & Kalt, supra note 26, at 201.
198. MacAvoy et al., supra note 27, at 227, 236.
200. See Over Half of Northwest Natural Gas’ Transporters Return to Sales Service, INDUS. ENERGY BULL., Feb. 3, 1994, at 3 (Northwest Natural Gas, an LDC, reported that many customers are returning to the LDC because of difficulties associated with contracting gas supplies and transportation.).
201. Broadman & Kalt, supra note 26, at 203.
202. Pierce, supra note 107, at 409-11.
load customers who do not perceive that they benefit marginally from open transportation. Again, however, this shift is probably only temporary.

Conclusion

As long as there is a core customer base that has only one provider for its gas service, there will not be an ideal solution to the regulation of natural gas distribution. The last segment of distribution will remain essentially monopolistic and price regulation of some sort will continue. The problem for regulators and utilities, however, is that some other portions of the market are competitive. Thus, the utility faces real challenges to its ability to earn a return on existing assets, and utility commissions lose the ability to stratify the market and shift costs to protect residential and other high-priority customers who cannot move to alternative services. Both planning and incentives offer some relief. Planning involves the commissions in the choices utilities will make. For the utilities, planning offers some protection from regulatory second-guessing. Incentive regulation, within certain parameters, offers all parties some of the benefits and risks of the newly restructured markets.

The proposed solution is imperfect and transitional. Imperfect solutions, however, will be common in an industry in which “gas is a commodity, but gas service is not.” Some regulation will be necessary in the transition period, and state commissions should make the best possible attempt to assure that an effective regime is in place.

203. _Id._ at 407.