15. Regulation of Natural-Gas Pipelines

For more than 150 years, downstream manufactured- and natural-gas operations have been the most regulated sector of the U.S. oil and gas industry. The first gas distribution company was regulated in 1817, and by the early twentieth century, every state regulated investor-owned distribution companies as public utilities. Other distribution companies were municipally owned and operated.

In response to problems with local and state regulation, federal regulation of interstate pipelines began in 1938 with the Natural Gas Act (NGA). After describing the rise and "fall" of state public-utility regulation of the gas industry, this chapter focuses on the nearly half-century experience with the NGA. Price regulation is examined through the study of the firm's valuation and allowed rates of return.

Certification regulation is described by examining Federal Power Commission (FPC), and later Federal Energy Regulatory Commission (FERC), policies on entry, exit, and service alterations. The record of regulation under the NGA is reviewed and the case for public-utility regulation of interstate gas pipelines reconsidered. The chapter ends with a cursory look at non-federal intervention—regulation and taxation on state and Indian land.

Industry problems and innovative responses that have changed not only the structure of the industry but regulation itself are examined in Appendix 15.1. Although much of the story would unfold after 1984, a clear trend toward spot-market gas purchases by end-users and transportation in place of traditional "bundled" utility service was evident. Appendix 15.2 studies gas import and export regulation, complementing the analysis of chapter 13 on petroleum import and export regulation.

Origins of Gas Usage and Regulation

Although instances of discovery, transmission, and use of natural gas are documented as far back as biblical times, commercial use of the vapor illuminant did not begin until the early nineteenth century.[1] In the United States, gas manufactured from soft (bituminous) coal was introduced for street lighting in 1817 by the Gas Light Company of Baltimore, four years after such lighting was inaugurated in England. Baltimore's example was followed by many U.S. cities in the East and then the Midwest and Pacific Coast. By 1870, manufactured gas provided lighting to forty-six cities.[2]

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[1] Malcolm W. H. Peebles, *Evolution of the Gas Industry* (New York: Macmillan, 1980), pp. 5–6, 21, 53.

[2] Malcolm W. H. Peebles, *Evolution of the Gas Industry,* pp. 53–54. Those cities included New York (1823), Brooklyn (1825), Boston (1829), Louisville and New Orleans (1832), Philadelphia (1834), Pittsburgh (1836), Cincinnati (1841), Albany (1845), Washington, D.C. (1848), and Chicago (1850). Martin G. Glaeser, *Outlines of Public Utility Economics* (New York: Macmillan, 1927), p. 52. The beginning dates in thirty-six major U.S. cities are provided in Arlon R. Tussing and Connie C. Barlow, *The Natural Gas Industry: Evolution, Structure, and Economics* (Cambridge, MA: Ballinger, 1984), p. 13.

Natural gas from shallow reservoirs was also utilized by nearby light companies as a cheaper substitute for artificial gas. This added risk to an already untested industry, however; as the reservoir became depleted, curtailment of service if not outright termination occurred.

Pipelines to transport natural gas first operated in the 1860s and 1870s in Pennsylvania and New York. The longest line was twenty-five miles; long-distance pipelines would wait until the next century when large-scale markets, long-life fields, and advanced pipe technology came of age.

The introduction of gas lighting in major U.S. cities had some critics. Moralistic concerns were raised about violating the divine nature of darkened nights and encouraging drunkenness, and some medical professionals warned of physical harm from artificial light. [3]

A more important hurdle was investor and consumer confidence. Explained Martin Glaeser:

> At first gas lighting was hardly more than a luxury or at most an expensive convenience. The industry had to sell its services to the consuming public and to establish its reputation for profitableness with investors. It had to experiment with production, transmission, and utilization problems in order to make service adequate, safe, and continuous.[4]

Industry and Regulation

Before the 1880s, gas companies were for the most part unregulated, although government involvement existed in various degrees. Some companies were municipally owned.[5] In some jurisdictions, limited-duration franchises were awarded to promote entry. Liberal privileges on public property and eminent-domain rights on private property reduced the cost of laying pipe for gas companies. Multiyear lighting contract with municipalities closed the door to new entrants.

Punitive control of rates and service, and uniform accounting standards and reporting requirements, were infrequently prescribed or moderate in effect. In 1817, a Baltimore ordinance required the Gas Light Company to charge a price not greater than rates in effect for other forms of illumination.[6] From 1855 to 1870, gas companies in Massachusetts could not declare dividends in excess of 7 percent over any five-year period in return for their limited-duration franchises.[7] All considered, subsidization more than penalization hallmarked early relations between government and gas. "There was no public demand for regulation of

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[3] Martin Glaeser, *Outlines of Public Utility Economics,* p. 53.

[4] Martin Glaeser, *Outlines of Public Utility Economics,* p. 53.

[5] Philadelphia in 1841 built and operated a gas manufacturing and distribution company. Other early municipal gas light companies were built in Hamilton, Ohio; Wheeling, West Virginia; and Charlottesville, Danville, and Richmond, Virginia. By the turn of the century, fifteen government gas companies were in operation, which by 1910 would balloon to over 100 before falling thereafter. Eliot Jones and Truman C. Bigham, *Principles of Public Utilities* (New York: Macmillan, 1931), p. 733.

[6] George Thomas Brown, *The Gas Light Company of Baltimore: A Study of Natural Monopoly* (Baltimore, MD: Johns Hopkins University Press, 1936), p. 18.

[7] Leonard D. White, "The Origin of Utility Commissions in Massachusetts," *Journal of Political Economy* 29, no. 3 (March 1921): 189.

the companies," John Gray stated. "Both the public and the companies were inclined to let well enough alone, and to jog along as they had been doing for so long a time."[8]

The early era was highly profitable for gas companies, "even after carrying the heavy burden of buying up competitors."[9] This dramatically changed in the 1880s when electric companies entered the scene and new gas firms attracted by high profits, some using a more efficient water-gas process, entered in unprecedented numbers.[10] Such new entry required overcoming legislatures "purchased" by the existing gas company in some cases.[11]

Before 1884, for example, six gas companies were chartered to serve New York City.[12] Under the new competition, the "advance-guards of industrial progress," as Gray described them, "made the air heavy with complaints about monopolies, extortionate prices, inadequate service, fabulous profits, and antiquated management."[13] For trade groups, such as the Gas Light Association of America (founded 1872),

> the question before [the emergence of these aggressive new forms of competition] had been how to prevent state interference. It now became how to stimulate, direct, and control state interference so as to protect investments. The gas men recognized that the days of high charges and high profits in the business were gone forever, and that they must abandon their previous position and claim protection for "honest investments." They realized, also, that a request for protection would raise the cry of monopoly, which could be safely met only by an acknowledgment of the state's right to regulate the monopoly in the public interest. The question now became simply how much of their previous claims the companies could afford to give up for the sake of state protection against rivals.[14]

Massachusetts was the opening shot in the gas manufacturers' and distributors' campaign to

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[8] John H. Gray, "The Gas Commission of Massachusetts," *Quarterly Journal of Economics* 14, no. 4 (August 1900): 514–15. The courts supported the concept of free pricing and free choice of clientele for gas firms. See Clyde O. Ruggles, "Government Control of Business," *Harvard Business Review* 24, no. 1 (Autumn 1945): 40.

[9] John H. Gray, "The Gas Commission of Massachusetts," p. 514.

[10] In 1880, coal-gas companies secured a Massachusetts law forbidding the sale of gas with 10 percent or more carbonic oxide, which precluded water-gas competition in the state. It was narrowly upheld in 1884 after a major legislative fight, which persuaded coal-gas firms to try another route for protection. Leonard D. White, "The Origin of Utility Commissions in Massachusetts," pp. 189–90.

[11] "If there was a gas company, the [city] council had usually been bought beforehand, and promoting an electric company involved outwitting both politicians and competitors." Forrest McDonald, *Insull* (Chicago, IL: University of Chicago Press, 1962), p. 30.

[12] Burton N. Behling, *Competition and Monopoly in Public Utility Industries* (Urbana, IL: University of Illinois Press, 1938), p. 19. Other cities with multi-firm gas service in the late nineteenth century included Chicago, Detroit, Brooklyn, San Francisco, New Orleans, Charleston, Indianapolis, Baltimore, Rochester, Memphis, St. Louis, Buffalo, Albany, Jersey City, Providence, Savannah, and Harrisburg. (Behling, p. 20.) For Insull's conclusion in 1894 that a utility was a natural monopoly, see Forrest McDonald, *Insull*, p. 68.

[13] John H. Gray, "The Gas Commission of Massachusetts," p. 515. Also see Clyde O. Ruggles, *Aspects of the Organization, Functions, and Financing of State Public Utility Commissions* (Boston, MA: Harvard Business School, 1937), p. 6.

[14] John H. Gray, "The Gas Commission of Massachusetts," pp. 515–16. He continued, "The remarkable thing was the suddenness and thoroughness with which the gas interests embraced the suggestion after so completely rejecting it for so many years" (p. 516).

foreclose competition. With the help of all major state newspapers except one, public opinion was swayed toward regulation by the lure of improved service and lower prices. A bill was drafted by the Boston Gas Company, and after intense legislative debate and revision "confined almost exclusively to the companies" (that is, not considering consumer or public interest issues), An Act to Create a Board of Gas Commissioners became law on June 11, 1885.[15] The franchise clause read:

> In any city or town in which a gas company exists in active operation, no other gas company or any other persons shall dig up and open the streets, lanes, and highways of such city or town, for the purpose of laying gas pipes therein, without the consent of the mayor and aldermen or selectmen of such city or town, after a public hearing … and notice to all parties interested.[16]

Despite the board's "summary powers as to rates and service" and the risk that restrictive provisions would be imposed, the tradeoff proved beneficial for established firms.[17] Entry was frozen, even when contracts were signed with customers at considerably cheaper prices by the would-be company.

In the first fifteen years of the law, all eighteen proposals for new entry were denied.[18] Rate and dividend regulation, to the extent it was effective, could be circumvented by overcapitalizing the firm to "lower" profits and dividends to permitted levels. High costs, including handsome salaries, could also benefit company interests yet satisfy regulatory confines intended to hold down consumer prices on a cost-plus basis. Dozens of new laws would be passed in Massachusetts to attempt to plug the regulatory gaps, but the law remained special-interest regulation by and for established coal-gas companies against upstart coal-gas and water-gas manufacturing companies.[19]

The creation of the Board of Gas Commissioners in Massachusetts was followed by similar regulation in other states—by industry demand. "Nearly all the gas associations of the United States for years recommended state commissions for all the states."[20] State authorities, in turn, welcomed a new sphere of influence and happily traded protection for restriction.

Standby price regulation was authorized in South Carolina (1895), Tennessee (1896),

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[15] John H. Gray, "The Gas Commission of Massachusetts," p. 518.

[16] John H. Gray, "Competition and Capitalization, as Controlled by the Massachusetts Gas Commission," *Quarterly Journal of Economics* 15, no. 2 (February 1901): 254n.

[17] "To protect themselves in their monopoly position the manufactures of coal gas secured the passage of an act creating a Board with a veto power over competitive projects, and as a consideration therefor submitted to regulation of the price and quality of gas and to publicity of their corporate affairs." Eliot Jones and Truman C. Bigham, *Principles of Public Utilities,* p. 164. Financial publicity, however, worked both ways. It could reveal a firm's high profits to its detriment, or it could reveal a competitor's strategies to discourage secretive price cutting and promote arm's-length cooperation.

[18] John H. Gray, "Competition and Capitalization, as Controlled by the Massachusetts Gas Commission," pp. 257–58.

[19] Approximately ninety new laws and amendments were passed in Massachusetts between 1885 and 1900 to make the original law more effective. They included "wide-reaching inquisitorial powers" to investigate firms' finances and practices. John H. Gray, "Competition and Capitalization, as Controlled by the Massachusetts Gas Commission," p. 271.

[20] John H. Gray, "The Gas Commission of Massachusetts," p. 516n.

Washington and Iowa (1897), Wisconsin (1898), and Mississippi (1899). Arkansas, California, Nebraska, Ohio, and the city of Chicago would soon follow. Regulation grew more prominent at the same time. Prices were fixed for a minimum period in Rhode Island (1891), Connecticut (1893), Florida (1897), and Illinois (1903).[21]

By this time, a powerful ally had come aboard. Beginning with an 1898 speech by electric-utility magnate Samuel Insull before the National Electric Light Association (later, Edison Electric Institute), a movement began to put the electric industry under state regulation. Competitive protection would be granted in return for regulation, a tradeoff similar to the one accepted earlier by gas companies (and railroads with the Interstate Commerce Act, as seen in chapter 11).

Industry support was initially lacking, but within a decade, both the NELA and the National Civic Federation endorsed Insull's plan. Allied with the gas industry and supportive state officials—and by documenting the history of franchises unaccompanied by regulation that left a trail of corruption and dissent—Insull prevailed.[22] Formal commissions and systematic regulation of rates and service would follow.

In 1905, New York State established the Commission of Gas and Electricity. In 1907, state and local regulation of public utilities reached a new plateau when New York expanded regulation with a new public service commission law, and Wisconsin and Georgia established formal utility commissions.

States that subsequently created similar commissions were Vermont (1909); Maryland and New Jersey (1910); California, Connecticut, Kansas, Nevada, New Hampshire, Ohio, Oregon, and Washington (1911); Arizona and Rhode Island (1912); Colorado, Idaho, Illinois, Indiana, Maine, Missouri, Montana, North Carolina, Oklahoma, Pennsylvania, and West Virginia (1913); Virginia (1914); Alabama, North Dakota, and Wyoming (1915); Utah (1917); Michigan and Tennessee (1919); Louisiana (1921); and South Carolina (1922).

By 1927, all forty-eight states—railroad commissions had regulatory authority in the remainder—had jurisdiction over the distribution of natural gas along with electricity and other "public utilities."[23] So along with telephone, telegraph, water, and electric companies, manufactured- and natural-gas distributors came under public-utility regulation to become the first comprehensively regulated sector of the U.S. energy market. This would have important implications when a problem of regulatory boundaries created political pressures to extend regulation to interstate gas-transmission firms in the 1930s, and ultimately to natural-gas production in the 1940s and 1950s.

[21] Van Sinderen Lindsley, *Rate Regulation of Gas and Electric Lighting* (New York: Banks Law Publishing, 1906), pp. 58–150.

[22] Forrest McDonald, *Insull*, pp. 84–88, 113–21; James Weinstein, *The Corporate Ideal in the Liberal State: 1900–1918* (Boston, MA: Beacon Press, 1968), pp. 24–26, 34–35. The threat of municipal control also turned the electric and gas industries toward regulation.

[23] For a list of state commissions and operating dates through 1936, see Clyde O. Ruggles, *Aspects of the Organization, Functions, and Financing of State Public Utility Commissions,* pp. 4–5. Later commissions were established in Delaware and Alaska (1960).

Some Misinterpretations

While the record is clear that gas companies spearheaded the movement to become regulated as public utilities, a misleading "textbook" view emerged that it was the public that had demanded regulation, and rightly so, because of the wastes of unregulated enterprise. Francis Welch expressed the traditional view:

> The public grew weary of the interminable rate wars which were invariably followed by a period of recoupment during which the victorious would attempt to make the price of the battle out of the consumers by way of increased rates. Investors suffered heavy losses through the manipulation of fly-by-night paper concerns operating with "nuisance" franchises. The industry suffered because such an erratic and unstable condition interfered with the necessary growth and improvement of service. Everybody suffered the inconvenience of city streets being constantly torn up and replaced by installation and relocation of duplicate facilities. The situation in New York city alone, prior to the major gas company consolidations, threatened municipal chaos.[24]

The preceding sketch of the historic wastes of utility competition, implying a need for government to foreclose competition and regulate a firm's operation at "competitive" levels, is open to historical revision and theoretical refutation. First, Welch reverses the historical sequence. It was primarily the industry, not the public, that "grew weary." The industry led the way to regulation and convinced the public while so doing. Second, many underhanded accounting practices that misled investors in the public-utility field occurred *after* regulation and not *before* regulation; regulation itself created perverse incentives to doctor financial reporting and engage in peculiar business practices. Observed George May:

> The [accounting] practices which had become discredited were more general in the regulated industries (and among the utility holding companies) and had spread from those fields to unregulated industry to only a minor extent where they had spread at all. This is true of the non-acceptance of the cost amortization concept of depreciation; of reappraisal and improper charges against capital surpluses resulting therefrom; of pyramiding of holding companies; of periodical stock dividends improperly accounted for; and of the practice of charging the surplus items which more properly belong in the income account.[25]

[24] Francis X. Welch, "The Odyssey of Gas—A Record of Industrial Courage," *Public Utilities Fortnightly,* October 12, 1939, pp. 501–2. Referring to the Maryland experience, George Brown states, "The evils of the competitive era of gas companies—the trafficking in gas company charters, the failure of 'competing' companies to compete and the wanton tearing up of the streets—caused a decided change in public opinion and the actions of the legislature." Brown, *The Gas Light Company of Baltimore,* p. 74. A recent restatement of unregulated entry as a "wasteful duplication of facilities and services" is found in Richard J. Pierce, Gary D. Allison, and Patrick H. Martin, *Economic Regulation: Energy, Transportation, and Utilities: Cases and Materials* (Indianapolis, IN: Bobbs-Merrill, 1980), p. 87.

[25] George O. May, "Accounting and Regulation," *Journal of Accountancy* 76 (October 1943): 296–97. For greater detail, see George O. May, *Financial Accounting: A Distillation of Experience* (New York: Macmillan, 1943), chaps. 7–9.

Restated, the book value of regulated companies was inflated and profits were understated to enable firms to charge higher rates, increase profits, and increase dividends within their cost-plus, franchised sphere.

Third, rate wars are erroneously assumed to be both wasteful and perpetual instead of a *process of discovery* whereby the most efficient firms emerge and a definite market structure is created. Without competition, it could not be known which firms are the most competent to assume a greater market share nor the optimum size of those firms. It is true that the discovery process might begin anew as a result of a new entry, but this ensures lowest cost provision of gas service. Potential competition is the omnipresent *check* on existing firms (including a "natural monopolist") and the correction for perceived existing inefficiency should actual entry take place.

Capital is scarce, and calculating investors learn from experience. Entrance is not undertaken on a lark or for disruption's sake but to outdistance the competition and win profits. To the extent this is accomplished, consumers are better served than they would be had "destructive" competition been disallowed. New entry and "duplication," in fact, often represented new applications of technology, broadened markets, and cheapened service. These advantages remained with later consolidation.

Price is also of concern to Welch and other critics; it is too low during rate wars and too high after. Undeniably, price wars benefit consumers by lowering prices.[26] When price cutting has run its course and prices return to levels at or above fixed costs, in addition to variable costs, this must be considered the "right" price because it resulted from a market discovery process and is the payback to investors upon whom the service depends. A price that is perceived by the market as not "right" (e.g., a price reflecting too much cost or profit, or both) invites entry and a new round of discovery to, once again, reveal competitive conditions.

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Criticism of the mainstream view does not imply that all was well in the early gas industry. Indeed, a careful reading of the complaints reveals that government intervention, as much as or more than the free market, was a source of industry problems. Government ownership of streets and their nonpriced use, as well as condemnation rights on private land, overencouraged subsurface construction.[27]

Under private ownership and voluntary exchange, pipeline right-of-way costs would have reflected the financial costs of street downtime and paving repair to ration marginal projects.

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[26] Burton N. Behling argues that "cut-throat competition favored the public for a time with low rates, but invariably at the expense of a deteriorated service." Behling, *Competition and Monopoly in Public Utility Industries,* p. 20. That argument smuggles in the value judgment that higher cost, higher quality service is preferred to lower cost, lower quality service. This is particularly elitist when it is realized that home heating and lighting were in the process of changing from luxury goods for the few to conveniences for the many. It also neglects the consumer preference for lower prices in the short run, other things the same.

[27] "The problem of excessive duplication of distribution systems is attributable to the failure of the community to set a proper price on the use of these scarce resources." Harold Demsetz, "Why Regulate Utilities?" *Journal of Law and Economics* 11, no. 1 (April 1968): 62.

Duplication of facilities would have been discouraged, and the inconvenience of construction would have been reduced to "market" levels.

Government franchise rights gave politically adept firms paper assets for "nuisance" use by "fly-by-night" entrepreneurs. Franchising and exclusive municipal-lighting contracts also weakened the discovery process by fostering collusion and territorial agreements that could not be threatened by new entry. And, widely recognized, the power to issue monopolistic grants corrupted authorities, which ironically contributed to sentiment for further regulation to "cure" the effects of prior regulation.[28]

The case for replacing "market failure" with regulatory surrogate "competition" fails to forthrightly consider the drawbacks of the "correction." Public-utility textbooks drawing upon the nineteenth-century experience condemn market practices to espouse intervention. Then, in a different context, it is admitted that the corrective regulation was experimental, imperfect, and "evolving." This skirts a crucial point. It is not enough to lambast the market; the critic must also assess the political alternative to see if the correction is worse than the problem. The rationale and practice of public-utility regulation have pronounced shortcomings, as seen later in this chapter, that make a revaluation of the market alternative imperative.

Early State Regulation

Controversies surrounding oil pipelines since their introduction in the 1860s did not extend to manufactured- and natural-gas transmission until many decades later. This was primarily because (1) industry integration lessened the conflict between gas producers and gas pipelines and (2) gas pipelines did not displace other modes of transportation. State common-carrier laws excluded gas pipelines, as did the Hepburn Act in 1906.

This changed after the turn of the century as gas markets began to grow and wellhead interests emerged. But as discussed in chapter 4, natural gas was often unmarketable because of limited storage and transport. Even when was connected by pipeline, gas did not command a high market price. This led discouraged producers to seek pipeline legislation to increase the marketability, if not the price, of natural gas.

Common-carrier statutes for intrastate gas lines were passed by California (1913), Oklahoma (1915), Louisiana (1920), New Mexico (1927), Michigan (1929), and North Dakota (1933) among others; common-purchaser laws were enacted in Oklahoma (1913), Louisiana (1918), Kentucky (1920), Michigan (1929), Texas (1931), Mississippi (1932) and Kansas (1935). To the extent that the requirement to transport or purchase all tendered gas equally ("ratably") discouraged pipeline investment, producers damaged their own interests by worsening the marketability (conservation) problem of natural gas.

State regulation of gas transmission attempted to restrict interstate commerce. In 1907, Oklahoma banned natural-gas exports to boost local industry at the expense of neighboring

[28] This major theme of regulation is explored in depth in chapter 29.

states. Challenged by a firm transporting gas from Oklahoma to Kansas, the statute was declared unconstitutional by the Supreme Court in 1911.[29]

Undeterred, in early 1919 West Virginia passed the Steptoe bill that prohibited interstate gas sales unless the gas was unmarketable intrastate.[30] The intention was to avert a third straight winter of shortages that closed factories and schools and stop an exodus of firms to Ohio. West Virginia had a strict price-control law, and state production was increasingly being diverted where "competition and public regulation are the least, and the willingness of the public to pay for gas is the greatest."[31]

This law was also declared in violation of the commerce clause of the Constitution by the nation's highest tribunal in 1923.[32] A final challenge to interstate gas transmission on the state level was made by Louisiana, which in 1924 forbade gas to be exported for the manufacture of carbon black. Cloaked in conservation garb, the law was not legally challenged and enjoyed longevity.[33]

Rates were another area of state jurisdiction over gas pipelines. Since 1889, states had regulated intrastate pipelines' sales to gas distributors in conjunction with their authority to regulate the latter.[34] Along with limiting gas utilities to cost-plus rates to limit the rate of returns to 7 to 9 percent, state authorities could prohibit costs from being passed through if a cost study of the wholesaler revealed "unjustified" profits.[35]

Indeed, without retail competition, wholesale demand was more price inelastic, to the advantage of gas pipelines (and producers) and to the disadvantage of gas consumers. Moreover, firms integrated over the wholesale and retail sectors could escape regulation by receiving at wholesale the profit not allowed at retail. To close the loophole, authorities focused on the utilities' cost of goods sold and used their authority to regulate at retail to force pipeline firms to lower their city-gate prices to permitted passthrough levels.

The question remained whether *interstate* sales by gas-pipeline companies could be regulated, as intrastate sales could be. This was no longer an academic question when long-distance gas transmission began to emerge in the 1920s. The first major case concerned a direct interstate sale to consumers, and the Supreme Court upheld a contention by New York State in 1920 that such transactions were local in nature, affected with a public interest, and

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[29] West, Attorney General of Oklahoma, v. Kansas Natural Gas Company, 221 U.S. 229 (1911).

[30] "Gas Conservation in West Virginia," *Oil & Gas Journal,* February 21, 1919, p. 48. Cited hereafter as *OGJ.*

[31] Philip P. Steptoe and George M. Hoffheimer, "Legislative Regulation of Natural Gas Supply in West Virginia," *West Virginia Law Quarterly* 25, no. 4 (June 1918): 262.

[32] Pennsylvania v. West Virginia, 262 U.S. 553 (1923).

[33] Yandell Boatner, "Legal History of Conservation of Oil and Gas in Louisiana," in American Bar Association, Section of Mineral and Natural Resources Law, *Legal History of Conservation of Oil and Gas* (Baltimore, MD: Lord Baltimore Press, 1939), p. 65.

[34] John D. Harris and Roger S. Randolph, "Federal Regulation of Natural Gas Industry Under the New Law," *OGJ,* June 30, 1938, p. 33.

[35] See the rate-of-return tables for gas utilities in Nelson Lee Smith, *The Fair Rate of Return in Public Utility Regulation* (New York: Houghton Mifflin, 1932), pp. 131, 146–49. This began as a 1928 PhD dissertation in economics at the University of Michigan. Smith left a professorship at Dartmouth to become a professional regulator in 1934. He was chairman of the FPC from 1947 to 1950.

subject to state regulation.[36] This left the area of wholesale interstate transactions unresolved, and in 1924, the Supreme Court drew the line on state authority by ruling that interstate pipeline firms were protected from price interference by the commerce clause.[37] This decision was joined two years later by a high-court decision that states could not regulate interstate gas sold to gas distributors.[38] States could regulate only the production and intrastate consumption of natural gas.[39]

These two rulings created a *regulatory gap* that encouraged pipeline investment in the interstate market—which became viable with the introduction of seamless pipe and the discovery of the prolific Amarillo (Texas) and Monroe (Louisiana) fields—and encouraged selling at wholesale rather than directly to homes and businesses.[40] This free-market oasis was recognized by critics, but rather than promote intrastate deregulation to end regulatory problems, they began to press for federal authority to regulate interstate as well.

The Move toward Federal Regulation

Federal intervention with natural-gas pipelines began modestly in 1920 when the Interior secretary was empowered to impose the "express condition" of common carriage on pipelines that received right-of-way on federal land.[41] In 1935, common-purchaser obligations were added to this requirement.[42] Whether Interior's authority extended to rate regulation would be the subject of later debate.[43]

Federal interest in interstate gas transmission began on February 15, 1928, when Senator Thomas Walsh (D-Mont.) introduced Senate Resolution 83 to investigate the market structure and economic performance of the electric and natural-gas industries and recommend policy. Congress approved a multiyear study by the Federal Power Commission, created in 1920 to regulate hydroelectric power, to investigate the need for regulation. Released in 1935, the findings strongly advocated a federal role with electricity and gas.

In 1934, President Franklin D. Roosevelt created by executive order the National Power Policies Commission to recommend legislation. With the support of the FPC and draft input by the National Association of Railroad and Utilities Commissioners, H.R. 5423 was introduced on February 6, 1935, by Texas Representative Sam Rayburn to regulate interstate

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36 Pennsylvania Gas Company v. Public Service Commission, 252 U.S. 23, 27–28 (1920).

37 Missouri v. Kansas Natural Gas Co., 265 U.S. 298, 309–10 (1924). The same verdict was rendered for interstate electricity sales. P.U.C. of Rhode Island v. Attleboro Steam and Electric Co., 273 U.S. 83, 89 (1927).

38 Peoples Natural Gas Co. v. Public Service Commission, 270 U.S. 550, 554–55 (1926).

39 Henderson Co. v. Thompson, 300 U.S. 258, 264–65 (1937).

40 See Donald Libert, "Legislative History of the Natural Gas Act," *Georgetown Law Journal* (June 1956): 695–723. For a list of eighteen major new pipeline projects in the 1925–31 period, mostly interstate, see Tussing and Barlow, *The Natural Gas Industry,* pp. 34–35. Before this time, only five short interstate lines had been built.

41 Mineral Leasing Act, Pub. L. 66-146, 41 Stat. 437 at 449 (1920).

42 Act of August 21, 1935, Pub. L. 74-297 1/2, 49 Stat. 674 at 678–79.

43 See *Montana-Dakota Utilities Co. v. FPC,* 169 F.2d 392, 395–96 (8th Cir., 1948); cert. denied 355 U.S. 853 (1948); and Chapman v. El Paso Natural Gas, 204 F.2d 46 (D.C. Cir. 1953).

sales of electricity and natural gas.

The bill had three parts: Title I, regulating interstate public-utility holding companies, Title II, regulating interstate electricity rates and entry, and Title III, regulating rates and entry of interstate natural-gas pipelines. On August 26, 1935, Title I became law as the Public Utility Holding Company Act (Wheeler-Rayburn Act),[44] and Title II became the Federal Power Act.[45] Title III was deleted because pipeline firms were against common carriage, a certification provision favoring intrastate lines, strict determination of allowable costs, and the regulation of sales for resale to industrial users.[46]

The Public Utility Holding Company Act directly affected integrated gas operations that were 10 percent or more owned by a holding company. The Securities and Exchange Commission was empowered to scrutinize and disaggregate holding companies to address three alleged problems: investor misinformation due to an "absence of uniform standard accounts;" nonregulated affiliates inflating charges to their regulated affiliates for passthrough; and obstruction of state regulation.[47]

Effective January 2, 1938, the commission (after notice and hearing) was to "limit the operations of the holding-company system of which such company is a part to a single integrated public-utility system, and to such other businesses as are reasonably incidental, or economically necessary or appropriate to the operations of such integrated public-utility system."[48] Exemptions were permitted if economies of scale were disrupted or the affiliates were located in one state.

Divestitures followed. Columbia Gas and Electric was split into an electric company and a gas company, with the latter spinning off Panhandle Eastern, an interstate gas-pipeline company. Jersey Standard divested Consolidated Natural Gas Company. Cities Service Gas Company split along geographic lines into three companies. The prospective effect was also significant. Summarized Arlon Tussing and Connie Barlow:

> Fifteen years after the passage of the [Public Utilities Holding Company Act], holding company control of interstate gas pipeline mileage had shrunk from 80 to 18 percent. New interstate pipelines, organized and built after 1935, almost always chose to avoid the act's jurisdiction by remaining completely free of distributor entanglements.[49]

By 1950, the requirement of the Public Utilities Holding Company Act had been responsible for divestitures totaling $16 billion.[50]

[44] Title I, Pub. L. 74-333, 49 Stat. 803 (1935).

[45] Title II, Pub. L. 74-333, 49 Stat. 838 (1935).

[46] M. Elizabeth Sanders, *The Regulation of Natural Gas: Policy and Politics, 1938–1978* (Philadelphia, PA: Temple University Press, 1981), p. 37. Objections to the gas bill were also raised by the coal industry, which feared that the common-carrier provision would increase the marketability of gas.

[47] Title I, § 1(b), Pub. L. 74-333, 49 Stat. 803-4 (1935).

[48] Title II, § 11 (b) (1), Pub. L. 74-333, 49 Stat, 803, 820.

[49] Tussing and Barlow, *The Natural Gas Industry,* p. 208.

[50] Securities and Exchange Commission, *Fifteenth Annual Report* (Washington, DC: Government Printing

Title III would be resurrected. The impetus for gas-pipeline regulation was a ninety-six-volume Federal Trade Commission report released during 1934 and 1935 that revealed a concentration of ownership among four interstate gas pipelines, which raised congressional fears of "holding-company control."[51] The study also cited a number of questionable practices suggesting a need for federal interstate regulation.

These scrutinized practices included territorial divisions, abnormal profits between (unregulated) pipelines and (regulated) distributors that were affiliated, and artificial asset write-ups. Another concern was "discrimination" between wellhead purchases on the one hand and the rates charged commercial and industrial users on the other.[52] The widely recognized "breakdown of regulation," it is important to note, was not linked to *existing regulation*—specifically franchise and rate-of-return regulation—but to the *absence of comprehensive regulation.*[53]

The "regulatory gap" had to be closed by further intervention, not removed by deregulation. Favored firms dared not renounce public-utility regulation that was more protectionist than restrictive. While franchise rights offered territorial monopolies, cost-plus ratemaking in an environment of large rate bases and good relations with the public-utility commissions minimized regulatory risk. This backdoor result of "monopoly pricing" could easily be laid on the doorstep of the interstate pipelines' wholesale price of natural gas. "Public-utility status," after all, was

> the haven of refuge for all aspiring monopolists who found it too difficult, too costly, or too precarious to secure and maintain monopoly by private action alone. Their future prosperity would be assured if only they could induce government to grant them monopoly power and to protect them against interlopers, provided always, of course, that government did not exact too high a price for its favors in the form of restrictive regulation.[54]

The gas bill needed to be reworked before major interstate firms would support it as the electric-utility industry had supported the Federal Power Act in 1935. By no means was

Office, 1950), pp. 62–63.

[51] Utility Corporations: Final Report of the Federal Trade Commission to the Senate of the United States Pursuant to S. Res. 83, Senate Doc. 92 (1936). The four largest carriers—Columbia Gas and Electric, Cities Service, Electric Bond and Share Company, and Standard Oil of New Jersey—controlled 59 percent of the interstate gas-pipeline market in 1934. M. Elizabeth Sanders, *The Regulation of Natural Gas,* p. 28.

[52] The wellhead discrimination charge has been rebutted in regard to oil pipelines in chapter 14, pp. 783–85, 843–44. Producers could have formally consolidated to seek better terms from pipeline purchasers or built joint-venture pipelines to achieve competitive parity. M. Elizabeth Sanders argued that established pipelines could block new entry by their influence with the financial community and gas distributors. M. Elizabeth Sanders, *The Regulation of Natural Gas*, p. 33. It is difficult, however, to see how any particular firm could persuade capital markets to forgo profitable opportunities. Regarding distributors, the absence of competition by law (franchise grants), not the free market, was primary.

[53] A sampling of opinion on the anti-consumer nature of public-utility regulation through the early 1930s can be found in William A. Prendergast, *Public Utilities and the People* (New York: D. Appleton-Century, 1933), pp. 266–77. Prendergast was a Theodore Roosevelt Progressive and served ten years as chairman of the Public Service Commission of New York State.

[54] Horace M. Gray, professor of economics at the University of Illinois, "The Passing of the Public Utility Concept" (1940), quoted in Walter Adams, "The Role of Competition in the Regulated Industries," *American Economic Review* 48, no. 2 (May 1958), p. 528.

regulation unwanted. Observed Gerald Nash:

> Representatives of gas companies were not at all unfriendly to the idea of federal regulation. For them, it promised uniformity and standardization in the interstate transmission of gas; this would reduce cutthroat competition and promote stabilization of the industry. At the same time, national regulation promised an escape from what they often considered onerous stipulations of state agencies.[55]

While state control was not unwelcomed, federal regulation was seen as correcting its shortcomings and potentially offering more—the opportunity to tame rivalry and stabilize the industry with cost-plus rates and thus facilitate profitability and financing in the post-holding-company era.

In March 1936, a gas bill was reintroduced by Representative Clarence Lea (D-Calif.), a former state public-utility commissioner, that removed most of the pipeline industry's objections. Industry support was tentative rather than enthusiastic, however. In testimony before a House subcommittee the next month, Floyd C. Brown of Natural Gas Pipeline Company of America, who was a bit defensive because of his company's valuation tiffs with the Illinois Commerce Commission, stated:

> Possibly State regulation should be supplemented by Federal control of interstate activities. In some instances, it might prove beneficial to the public as well as to the transmission company, and in others it would undoubtedly be detrimental to one or both. No gas company should fear or oppose Federal regulation and control if the authority so granted is administered fairly by the commission to whom these broad powers are entrusted. However, before creating a new bureau or a department under existing commissions, with the added expense for valuations, hearings, fields, and offices administration and attendant delays under even the most harmonious proceedings, we should be fully convinced that there is need for this type of legislation and control.[56]

Brown, the only interstate-pipeline witness, also drew attention to the fact that natural gas under regulation would be less flexible to compete with coal and fuel oil, which were not subject to public-utility control.[57]

John Battle of the National Association of Bituminous Coal Organization was also undecided about regulation that had the potential to either lower or raise gas prices. Although he

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[55] Gerald Nash, *United States Oil Policy* (Westport, CT: Greenwood Press, 1968), pp. 212–13. Also see M. Elizabeth Sanders, *The Regulation of Natural Gas,* p. 195. The 1935 gas bill also included mandatory conservation by gas producers to "protect the investment" of pipelines.

[56] *Natural Gas, Hearing before a Subcommittee of the House Committee on Interstate and Foreign Commerce,* 74th Cong., 2d sess. (Washington, D.C.: Government Printing Office, 1936) (Statement of Floyd C. Brown), p. 102. This hearing is cited hereafter as *Natural Gas I.* Also see Kenneth Marcus, *The National Government and the Natural Gas Industry, 1946–1956* (PhD diss., University of Illinois, 1962; repr., New York: Arno Press, 1979), pp. 114–15. Representative Rayburn's interest in the bill waned (although he continued to favor it), presumably because of the exclusion of common carriage desired by Texas gas producers.

[57] "Prompt decision by management, without the delay of preparing valuations and holding rate hearings to meet the competition of any unregulated competitive fuels, is essential." *Natural Gas I,* p. 103.

complained of "unfair competition" from "unreasonably low" industrial gas prices, his position was that "if you are going to have the Federal Government going into that realm I think that it ought to make a good job of it."[58] The present bill was described as "practically nil insofar as benefiting anyone is concerned."[59]

In contrast, the government witnesses welcomed an expansion to interstate regulation with little reservation. Dozier DeVane representing the FPC favorably compared the bill to the Federal Power Act to argue its constitutionality.[60] William Chantland of the Federal Trade Commission complained about "starvation ... in the midst of plenty" with wellhead waste by producers on the one end and monopolistic pipelines restricting throughput to leave communities unserved on the other.[61]

John Benton of the National Association of Railroad and Utilities Commissioners endorsed federal regulation to address the regulatory gap so long as existing state jurisdiction was not invaded.[62] Communications submitted to the subcommittee from utility regulators from Missouri, Illinois, Kansas, and Alabama also supported the bill. But while the House approved the bill, Senate confirmation was not forthcoming. Another try was necessary.

In early 1937, Lea again introduced a gas bill with an alteration that would prove to be the "winning formula"—restrictions on pipeline entry into occupied interstate markets.[63] Section 7(c) of the proposed bill required certificates from the FPC for new entrants, which put the burden of proof on would-be pipelines. This protective provision cajoled the pipeline industry into cautious support, enough when combined with outside support to ensure the bill's passage.

In House testimony in March 1937, the FPC, the Federal Trade Commission, and state regulatory bodies remained united behind interstate regulation. State utility regulators were frustrated by the regulatory gap, and federal officials recognized expanded career opportunities.[64] The National Coal Association (formerly the National Association of Bituminous Coal Organization), on the other hand, remained ambivalent. Even with section 7(c), they were not sure if natural-gas prices would be higher or lower. In testimony they reiterated their concern that the bill was ineffectual and not of benefit to anyone since their concern about industrial gas rates was not addressed.[65]

The interstate natural-gas industry again offered one witness. M. A. Dougherty, a New York

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58 *Natural Gas I*, p. 79.

59 *Natural Gas I,* p. 71.

60 *Natural Gas I,* pp. 10–46.

61 *Natural Gas I,* pp. 55–56. Chantland did concede in questioning that excess capacity, even with storage capabilities, was attributable to the obligation to meet peak residential load during severe winter weather and to serve seasonal manufacturing industries (pp. 62–63).

62 *Natural Gas I,* pp. 84–98.

63 M. Elizabeth Sanders, *The Regulation of Natural Gas,* p. 40; and Donald Libert, "Legislative History of the Natural Gas Act," p. 711.

64 M. Elizabeth Sanders, *The Regulation of Natural Gas,* pp. 46–53; and Kenneth Marcus, *The National Government and the Natural Gas Industry,* pp. 119–22.

65 *Natural Gas, Hearings before the House Committee on Interstate and Foreign Commerce,* 75th Cong., 1st sess. (Washington, DC: Government Printing Office, 1937), pp. 120–23. Cited hereafter as *Natural Gas II.*

lawyer, represented four interstates: Colorado Interstate Gas Co., Mississippi River Fuel Corporation, Interstate Natural Gas Co., and New York State Natural Gas Co. After suggesting a number of changes to the draft to reduce the expense and paperwork for the industry, Dougherty expressed his support for section 7(c) as a common covenant in interstate regulation and for promoting conservation. When asked about the industry's interest in the entire bill, Dougherty responded:

> We have no objection to the bill. We are not opposing it.... We think that generally it is sound regulation. It follows the lines of regulation in many of the states. Frankly, I think about the only result that will occur is increased cost both to the Federal Government... and to the companies. I do not believe that the expense that is going to be incurred by these companies, that ultimately must be paid by the rate payers and the consumer, is going to find its benefits in as greatly a reduced rate as some of these city officials feel that they will get; but we have no objection to the Federal Government stepping into this field of regulation.[66]

The sudden inclusion of section 7(c) after three years of legislative drafts and debate did not go unopposed in the committee hearings. Cities Alliance, an alliance of 100 midwestern cities dedicated to "securing natural gas at proper rates," stated,

> After 2 years of vigorous effort to free the natural-gas industry from unlawful monopolistic restraint, [we] are alarmed by any possibility that the Congress might, inadvertently, give its blessing to the practices and philosophy of monopolistic control now dominating the production, transportation, and distribution of natural gas throughput this nation.[67]

Ten reasons were given by Cities Alliance to delete the section:

1. It would "creat[e] a towering bureaucracy that feeds upon itself."[68]
2. It unnecessarily duplicates local and state authority already regulating gas service.
3. "It improperly assumes that a Federal bureau here at Washington has a better knowledge of just what constitutes 'public necessity and convenience' ... than do the cities, counties, and States which are directly affected."[69]
4. It would discourage municipal ownership or service from a new distribution company.
5. It would indirectly promote waste by redirecting gas reserves toward inferior uses such as carbon-black manufacture and gas stripping.
6. "It would impose unfair and rigid requirements upon an industry which is still young and growing lustily."[70]
7. It discourages "legitimate freedom of opportunity."[71]

[66] *Natural Gas II,* p. 135. When later asked by a congressman if the proposed legislation "contains any death sentence" for the industry, Dougherty replied: "No; I do not think so. We will keep on selling gas." *Natural Gas II,* p. 135.

[67] *Natural Gas II,* p. 61.

[68] *Natural Gas II,* p. 63.

[69] *Natural Gas II,* p. 64.

[70] *Natural Gas II,* p. 64. Further, "Is it wise to clothe a toddling youngster in an old man's pantaloons and expect him to run a race against his older brothers—the oil, the coal, and the electric-power industries?" (*Natural Gas II,* p. 65).

[71] *Natural Gas II,* p. 65.

8. It gives the established pipeline the opportunity to simply expand its facilities to block an applicant.
9. New entry would be "subjected to unfair hazards incident to the delay in obtaining a Federal certificate."[72]
10. "It offers to powerful and wealthy pipe-line companies an endless opportunity to frustrate independent enterprise, frustrate the commission, and frustrate the public's own rate-reduction efforts by resorting to litigation ... which is not available to them at this time."[73]

Permit hearings on the local and state levels, indeed, had witnessed coal and fuel-oil interests arguing to block entry of natural gas into their markets.[74]

Cities Alliance also rebutted the argument that section 7(c) was necessary to prevent a wasteful duplication of facilities. Cutthroat pricing, it was argued, would lower the rate of return to threaten the entrant's financing. If, on the other hand, lower prices could generate a bankable rate of return, consumers would benefit.[75]

Three congressmen defended section 7(c) in the face of Cities Alliance's challenge. Congressman Charles Halleck (R-Ind.) argued that "throughout the whole history of expanding government regulation and control of public utilities ... a provision similar to ... Section 7(c) has been applied."[76] He also asserted that competition had failed to bring gas prices down, a point that Cities Alliance vigorously denied.[77]

Congressman Samuel Pettengill (D-Ind.) recognized a tradeoff between regulated rates and territorial protection. The first without the second, he opined, would hamper the incentive for natural-gas firms to expand to new markets.[78] Congressman Lea of California, who claimed authorship of the controversial section, stated that the certificate obligation was more necessary with gas than electricity because gas was a wasting asset in great need of conservation.[79] To him, fewer head-to-head confrontations assured more supply for consumers.

Although many of Cities Alliance's arguments could be used against interstate regulation (and intrastate regulation as well), the nation's first natural-gas consumer group decided to side with federal regulation. They had already used antitrust action to police the industry; they now proposed an amendment requiring compulsory pipeline extensions to nonserviced areas, although it would not be adopted.[80]

This left the free-market alternative of removing state regulation to close the regulatory gap without a sponsor much less a champion. On June 14, the House approved H.R. 6586.

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[72] *Natural Gas II,* p. 65.
[73] *Natural Gas II,* pp. 65–66.
[74] See, for example, "Fuel Fight," *Business Week,* November 11, 1933, p. 19.
[75] *Natural Gas II,* p. 62.
[76] *Natural Gas II,* p. 76.
[77] *Natural Gas II,* p. 82.
[78] *Natural Gas II,* p. 77.
[79] *Natural Gas II,* pp. 81, 83.
[80] *Natural Gas II,* p. 66.

The Senate discussed natural-gas legislation but did not hold formal hearings. The Committee on Interstate Commerce recommended passage of the House version without amendment. This was due in large part to the popularity of the bill among state regulators and federal officials and an absence of reservation within the gas industry itself. It was repeatedly noted that there was no opposition from any quarter.

Judging by Senate discussion, the gas industry had grown more comfortable with interstate regulation since the House hearings five months before. Senator Burton Wheeler (D-Mont.) attributed industry support to the fact that "they would rather have one body here in Washington regulate the interstate features of the matter than to have a lot of States try to regulate shipments."[81] He added:

> The authorities of cities like Columbus, Cleveland, Detroit, St. Louis, Chicago, Kansas City, and every single city in the United States that imports gas, have written me and begged me and pleaded with me to try to get this bill passed. Likewise ... every State regulatory body has asked for it, and there has not been an objection that I know of coming from the transporters or producers of gas anywhere in the United States. In fact, one of them spoke to me abut the matter and said he hoped the bill would pass, because he felt that it would stabilize the industry, and stop the industry from being held up to ridicule.[82]

There was concern, as on the House side, about gas producers falling under regulation. Although the Senate was assured that state and not federal authority was controlling, its concern foreshadowed a difficult interpretive question under the just-and-reasonable standard that would surface in the 1940s and culminate with the 1954 *Phillips* decision.[83]

On June 7, 1938, the Senate passed H.R. 6586 with minor revisions. The House accepted all but one of the amendments on June 13, and the Senate concurred the next day. On June 21, President Roosevelt signed the NGA into law.[84] A $2.5-billion industry serving 8 million customers in thirty-five states was now regulated. Major jurisdictional pipelines, which transported approximately one-fourth of all gas produced in the country, are listed in table 15.1.

Natural Gas Act of 1938

Effective six months after enactment, the NGA closely resembled the Federal Power Act of 1935 regulating electricity sales.[85] Prefaced on the "public interest" in interstate commerce,

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[81] *Congressional Record,* 75th Cong., 1st sess. (August 19, 1937), p. 9312.

[82] *Congressional Record,* 75th Cong., 1st sess. (August 19, 1937), p. 9315. Added Texas Senator Tom Connally: "I have not had a letter for this bill, nor, so far as I recall, a letter against it. I have no particular interest in this matter, except that the bill does affect a large industry in my state. We want to sell our gas, of course, but we do not want to sell it at a price that is not just and fair" (p. 9316).

[83] See chapter 8, pp. 376–79.

[84] Pub. L. 75-688, 52 Stat. 821 (1938).

[85] Dozier DeVane, "Highlights of Legislative History of the Federal Power Act of 1935 and the Natural Gas Act of 1938," *George Washington Law Review* 14, no. 1 (December 1945): 38–39.

the act gave the FPC public-utility jurisdiction over rates, entry, and extension and abandonment of service. Rates were to be "just and reasonable," implying a market return on original cost, without "any undue preference or advantage" between city gates.[86] Tariffs were to be filed with the FPC and could not be changed for thirty days unless permitted by the commission. Filed tariffs could be challenged and brought to hearing by the FPC, but submitted rates, with a maximum five-month suspension period, could become effective if an escrow account was created to provide refunds should the approved rate fall below the interim rate. In no case could a hearing result in a rate determination above that filed; only reductions could be ordered.

Another major concern was entry, which was the most palatable aspect of the law to the interstate gas-pipeline industry. While an established firm could "enlarge or extend its facilities for the purpose of supplying increased market demands in the territory in which it operates," new firms could not enter "a market in which natural gas is already being served by another natural-gas company" unless per hearing, a certificate of public convenience and necessity was obtained.[87]

Table 15.1
JURISDICTIONAL PIPELINES UNDER THE NATURAL GAS ACT OF 1938

Year Completed	Company	From–To	Miles	Diameter (inches)
1925	Magnolia	Louisiana–Texas	214	14–18
1925	Dixie-Gulf	Louisiana–Texas	217	22
1926	Interstate	Louisiana–Texas	170	22
1927	Cities Service	Texas–Kansas	250	20
1928	Colorado Interstate	Texas–Colorado	350	20–22
1928	United	Texas–Mexico	141	18
1928	Mississippi Interstate	Texas–Missouri	350	20–22
1929	El Paso	New Mexico–Texas	218	16
1929	Southern Natural	Louisiana–Georgia	460	20–22
1929	Texas Gas Trans.	Louisiana–Tennessee	210	18
1929	Mountain Fuel	Wyoming–Utah	290	14–18
1930	Northern Natural	Texas–Minnesota	1,100	24–26
1931	Natural Gas America	Texas–Illinois	980	24
1931	Panhandle Eastern	Texas–Indiana	900	20–24
1931	Columbia	Kentucky–Wash., D.C.	467	20
1932	Western	Texas–Arizona	275	–
1936	Panhandle Eastern	Indiana–Michigan	300	–

SOURCE: Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* pp. 34–35.

Service abandonments also required FPC approval.[88] On the other hand, a firm could be ordered to "extend or improve its transportation facilities" to supply gas distributors if

[86] Secs. 4(a) and 4(b), Pub. L. 75-688, 52 Stat. 821 at 822 (1935).
[87] Sec. 7(c), Pub. L. 75-688, 52 Stat. 825 (1935).
[88] Sec. 7(b), Pub. L. 75-688, 52 Stat. 824 (1935).

existing service was not impaired.[89] Enlargement of mainline facilities could not be required.

Other sections of the NGA embellished the above-mentioned areas of jurisdiction. The commission could prescribe accounting methods, require records and reports, and undertake inspection and investigation. State conservation efforts were to be aided where informationally possible. Imports and exports of natural gas were to be regulated in the "public interest."[90] Executives of interstate pipeline firms were to forgo active trading of company securities. The remainder of the act prescribed the machinery of enforcement.

The parameters of the NGA can be better fathomed by noting what was not regulated. Security issues, consolidations, mergers, and gas-property sales were uncontrolled. Fixed-rate floors or ceilings were not prescribed. Conservation measures analogous to state natural-gas statutes were absent. So was the authority to regulate retail gas sales—state jurisdiction prevailed in both cases. It was specifically mentioned (section 1[b]) that the act "shall not apply ... to the production or gathering of natural gas." Section 5(b), however, gave the FPC jurisdiction to "investigate and determine the cost of the production or transportation of natural gas." These two clauses would have important ramifications in the decades to follow.

§§

The NGA has been described by Elizabeth Sanders as "cut from the same cloth as other New Deal economic regulatory statutes."[91] This is oversimplified. While industries wrote their own codes of fair competition under the National Industrial Recovery Act, the gas industry played a more reserved role with the NGA. Affected pipeline firms were moderately favorable if not apathetic toward federal regulation, whereas the National Industrial Recovery Act program was wholeheartedly endorsed by the involved industries.

What the 1938 law represented was "but another example of the trend toward regulation of the interstate phases of industry by federal agencies."[92] The NGA was not born of FDR's "new" program of government intervention in the economy; it was a legacy of *Munn v. Illinois* (1877) and interstate regulation of transportation "affected with a public interest" that began with the Interstate Commerce Act of 1887.

This point was made in a speech before the American Gas Association, shortly after the NGA was passed, by the president of the National Association of Railroad and Utilities Commissioners, an organization instrumental in passage of the NGA:

> I wish to dispel the thought that the regulations as we know it today is a child of the present decade, something novel or experimental.... With the

[89] Sec. 7(a), Pub. L. 75-688, 52 Stat. 824 (1935).

[90] See appendix 15.2, pp. 961–70.

[91] M. Elizabeth Sanders, *The Regulation of Natural Gas,* p. 44.

[92] John D. Harris and Roger S. Randolph, "Natural Gas Industry Under the New Law," *OGJ,* June 30, 1938, p. 105. FPC acting chairman Clyde Seavey similarly described the law as "a logical development ... the next step in governmental regulation ... merely extending to natural gas companies engaged in interstate commerce somewhat the same supervision that had been exercised over electric and transportation utilities." Clyde L. Seavey, "Federal Regulation of Natural Gas," *Public Utilities Fortnightly,* October 13, 1938, p. 505.

> background [of regulation] as it is, no one ... can justly say that the enactment of ... the federal natural gas act... unduly broadens the field of administrative control.[93]

Viewed from the gas-distribution angle, a vexing regulatory gap was closed; state authority over retail sales of interstate gas was now complemented by federal regulation of wholesale transactions of interstate gas. Nonetheless, while one gap may have been closed, another gap was opened. Although profits could be regulated to "normal" levels at the wholesale and retail levels, costs could not; indeed, as pipelines had previously, natural-gas producers occupied an advantageous position to receive premium prices as the unregulated link in a cost-plus industry that was franchised at the retail level.

Restrictions on new entry in markets already served by gas pipelines reinforced this proclivity. While unrestricted entry could deter undisciplined practices by existing firms, protected markets all but assured the opposite. This was recognized by Cities Alliance (and coal interests favoring higher natural-gas prices), but it was believed that cost-plus regulation, calculated on a specified return on investment, could neutralize section 7(c).[94]

Interstate gas-pipeline rates were made inflexible and susceptible to *political* rather than *economic* determination under the NGA. This complicated economic calculations by entrepreneurs and investors and spread misinformation throughout the economic system regarding the relative scarcities of competing fuels. Inflexibility was also imparted by limiting entry, requiring extensions, and blocking terminations.

General and administrative expenses of firms were increased by reporting requirements and hearing defenses. Full public disclosure of business practices gave companies full knowledge of each other, which reduced the quest for competitive differentiation. The taxpayer, too, would share the burden; the FPC would be significantly enlarged to take on its new responsibilities.

Regulation under the NGA: 1938–84

Henceforth, interstate gas-transmission companies were regulated as public utilities with entry and exit, rates, and extension and abandonment of service controlled by the FPC (1938–77) and the Federal Energy Regulatory Commission (FERC, 1977–84). With the NGA upheld as constitutional in 1942,[95] the FPC worked to define jurisdiction, implement an accounting framework to determine costs and revenue, devise a valuation (ratebase) formula and a rate of return based on it, and settle various certification issues under the law. Although no legislative overhaul (or threat of the same) occurred with pipeline regulation as had happened with the field-price regulation of natural gas, several amendments were significant.

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[93] Alexander Mahood, "The Development of Regulatory Processes," *A.G.A. Proceedings—1938* (New York: American Gas Association, 1938), p. 43.

[94] The NGA addressed cost inflating in section 14(b), subjecting pipeline-company purchases of mineral acreage—that could be used to pad the rate base in the short run and yield large future production to sell at unregulated prices—to reasonableness reviews.

[95] *Federal Power Commission* v. *Natural Gas Pipeline Company of America,* 315 U.S. 575 (1942).

Jurisdictional Authority

The NGA encompassed interstate "sales for resale" of natural gas. This precluded regulation of gas-distribution companies and pipeline transactions with industrial users, which came under the regulatory purview of state and local authorities.[96] Federal jurisdiction extended to interstate gas-transmission companies selling gas to distributors and, controversially, producers selling gas to interstate carriers.[97] The latter became *the* major area of jurisdictional dispute.

As discussed in chapter 8, the question arose of whether the FPC could regulate the gas-acquisition costs of interstate pipelines, which meant price control at the producer-gatherer-processor "field" level. Two commission decisions in 1940 set a precedent that arm's-length sales from producers to unaffiliated pipeline firms could be automatically passed through, while transactions between affiliated companies, creating situations where effective regulation could be circumvented, were subject to commission review and possible disqualification.

This demarcation continued precariously over the next decade, although in several decisions the commission and courts employed language suggesting that the NGA extended to all producers by virtue of *sale* to interstate carriers *for resale.* This prompted legislative action by producers to amend the NGA to confine regulation to affiliated producers only, while exempting independents. A presidential veto in 1950 prevented this from taking place, and in 1954, long-foreshadowed comprehensive field regulation of natural gas came to pass in the Supreme Court's *Phillips* decision. This incited another legislative attempt in 1956 to exclude nonaffiliated producers from FPC regulation, which again met a presidential veto.[98]

During the jurisdictional dispute, a related controversy was whether the FPC could regulate pipeline decisions intended to circumvent field regulation. It involved the commission's below-market valuation of reserves in the rate base, discussed in the next section, that penalized pipeline firms that internally supplied their gas needs rather than purchased gas from independents.

In 1948, Panhandle Eastern Pipeline sold its producing properties to circumvent this discrimination. This was challenged by regulators who feared higher gas-acquisition costs for distributors. Rejecting the agency's contention that it was its own jurisdictional judge, the Supreme Court in 1949 upheld Panhandle's reasoning that "ratemaking is not a precedent for regulation of any part of production and marketing," which was held to be local in nature.[99] If the long arm of the FPC reached the field price of natural gas under certain conditions, other field activities were left to the states to regulate or not.

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[96] In 1947, states were granted authority to regulate sales from interstate pipelines to industrial customers, authority that Congress in 1942 refused to give to the FPC. See this chapter, pp. 883–84.

[97] A regulatory bias on the federal, state, and local levels has been to discourage gas-transmission companies from vertically integrating into residential and commercial retailing.

[98] See chapter 8, pp. 379–83.

[99] *Federal Power Commission* v. *Panhandle Eastern Pipe Line Company,* 337 U.S. 498 (1949).

A second jurisdictional question was whether an intrastate pipeline became subject to federal regulation if a sale or purchase was made with an interstate carrier. On February 14, 1949, the U.S. Court of Appeals ruled that the East Ohio Gas Company, a firm (wholly engaged in intrastate activities) that purchased gas from an interstate line for resale, was not covered by the NGA.[100] This was reversed by the Supreme Court, which held that "continuous flow of gas from other states through East Ohio's high-pressure lines constitutes interstate transportation."[101]

Amendments to the NGA

Section 7(a) of the original act empowered the FPC to compel a firm to "extend or improve its transportation facilities" and connect with distributors if "no undue burden will be placed upon such natural-gas company." Pipeline enlargement could not be required; neither could forced connections "impair[ing] ... [the firm's] ability to render adequate service to its customers." Section 7(b) prohibited a firm from abandoning all or part of its service without a "finding" by the FPC that "the present or future public convenience or necessity" would be maintained.

Section 7 Expansion: 1942. Next to the producer jurisdictional question, section 7(c) would prove to be the most crucial and problematical part of the act. Construction of a new line "to a market in which natural gas is already being served," or an ownership transfer of interstate gas-pipeline properties, required a certificate of public convenience and necessity. New activity did not require federal permission but came under NGA regulation once service commenced. Reflecting the lobbying of Cities Alliance, who recognized the anti-competitive potential of certification, the concluding language of section 7(c) weakened the statute to limit protectionism for vested interstates and rival sources of energy (fuel oil and coal). The 1938 version read:

> In passing on applications for certificates of public convenience and necessity, the Commission shall give due consideration to the applicant's ability to render and maintain adequate service at rates lower than those prevailing in the territory to be served; it being the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.[102]

After three years of operation, the gas industry, competing fuel interests, and state and federal regulators were ready to amend section 7(c) in anti-consumer directions. Cities Alliance was no longer a participant.

The gas industry and FPC both complained that tedious certification hearings were occurring for all new projects, not just those in areas that had existing service. This unintended result

[100] *East Ohio Gas Co.* v. *Federal Power Commission,* 173 F.2d 429 (D.C. Cir.1949).

[101] *Federal Power Commission* v. *East Ohio Gas Co. et al.,* 338 U.S. 464 (1950).

[102] Pub. L. 75-688, 52 Stat. 825 (1938).

came from the ambiguity of the statute and the conservatism of creditors toward new projects. The phrase "market in which natural gas is already being served by another natural gas company" left the key terms "market" and "another natural gas company" undefined.

With the same companies getting gas from the same general regions, and projects often criss-crossed on the way to markets, the firms sought a ruling from the commission.[103] A pipeline witness specifically mentioned his company's situation of trying to enter the Wisconsin market that two other firms proposed to enter. Each of the three sought regulatory permission, so the Wisconsin Public Service Commission called a comparative hearing after the FPC declined.[104] State jurisdiction over interstate projects was not what the interstate pipeline industry desired.

While the interstate industry pragmatically supported reform so long as several provisions were enacted (see below), the real winners from an expansion of certification regulation were the FPC and the alternate-fuel industries. Federal authorities welcomed an expansion of their charter to plug the regulatory gap by giving itself "an opportunity to scrutinize the financial set-up, the adequacy of the gas reserves, the feasibility of the proposed services, and the characteristics of the rate structure at a time when such vital matters can be revised and modified as the public interest demands."[105]

Fuel-oil and coal interests, prominently including the railroad industry, sought expanded certification to achieve "the right to full participation" in commission hearings.[106] While the anti-gas lobby was already active before the FPC,[107] they now had full authority to intervene in hearings and block—or at least delay—gas-industry competition.

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Effective February 7, 1942, section 7(c) certificates were required for all construction or extension of pipeline facilities in interstate commerce.[108] Two provisions were added at the request of the gas industry. The commission could authorize a temporary certificate "in cases of emergency, to assure maintenance of adequate service" without notice to intervening parties and a hearing. Second, existing lines built without a certificate were exempted from getting one. The authority for pipelines to use their original certificate to expand their facilities to meet increased demand in their service territories was retained and placed in

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[103] William Dougherty, representing the same interstates as before, explained the industry's predicament: "Everybody who wants to build a line apparently feels that to be sure about these things they have either got to come into the Commission and either get a definition of jurisdiction or a certificate.... [Gas production] all originates either in Texas, Louisiana, or Oklahoma, and you radiate from that area, and every new pipe line is bound to cross the path of some existing pipe line." *Natural Gas Act Amendments, Hearings before the House Committee on Interstate and Foreign Commerce,* 77th Cong., 1st sess. (Washington, DC: Government Printing Office, 1941), p. 35.

[104] *Natural Gas Act Amendments* (1941), p. 59.

[105] *Natural Gas Act Amendments* (1941), p. 6.

[106] *Natural Gas Act Amendments* (1941), p. 51.

[107] "[The commissioners] have been very patient with us and probably strained themselves a little bit to let us in." Testimony of John Battle, executive secretary of the National Coal Association. *Natural Gas Act Amendments* (1941), p. 51.

[108] Pub. L. 77-444, 56 Stat. 83 at 84 (1942).

section 7(f).

A new subsection, section 7(g), weakened the consumerist language of section 7(c) quoted above. It read:

> Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company.[109]

Section 7 was enlarged with two other subsections. Section 7(d) described the procedure for applying for certification, while section 7(e) gave the FPC authority to attach reasonable terms and conditions to the certificate as the "public convenience and necessity" may require.

The revised NGA was still "pluralist" to the extent that exclusive franchise rights were not given to the first entrant. But the competitive distortion of the original act was exacerbated by the extension of certification requirements. More red tape joined natural economic considerations between the entrepreneurial idea and reality of entry or expansion. Antagonistic parties—coal, fuel oil, and entrenched pipeline interests—were given a noneconomic means to forestall new gas service to industrial, commercial, and residential markets.

Rights of Eminent Domain: 1947. While rights of eminent domain were raised as an issue in the 1941 House hearings to amend the NGA,[110] they became a more urgent issue after the war. In House and Senate hearings in 1947, a variety of complaints and reasons for enacting a federal condemnation law for interstate lines were aired. Natural Gas Pipe Line was having trouble completing an FPC-authorized expansion to the growing Chicago market because of selected landowner holdouts.[111] Texas Eastern was seeking to assume the wartime condemnation rulings as part of its purchase of the Big Inch and Little Inch pipelines from the federal government. Texas Eastern also desired prospective eminent-domain rights to construct laterals to begin gas service from the former oil lines.

Congress was sympathetic to the argument that higher right-of-way costs from holdout property owners were passed through to consumers. Interstate-pipeline interests complained that state condemnation rights often did not extend to interstate lines that went through the state but did not sell gas there. Other state eminent-domain laws did not apply to out-of-state

[109] Pub. L. 77-444, 56 Stat. 83 at 84 (1942).

[110] See the testimony of J. J. Hedrick, representing Natural Gas Pipeline Company of America, who complained of railroad obstructionism against pipeline right-of-way "for the past 2 years." *Natural Gas Act Amendments* (1941), p. 54.

[111] The reasons for landowner holdouts often were not petty. Stated one interstate representative: "The difficulties of this company are somewhat intensified by the fact that it is required to build its line through the relatively thickly settled and valuable Chicago suburban area, where every farmer envisions his tract as the site of a future subdivision and resents anything which will tend to minimize this possibility." *Amendments to the Natural Gas Act, Hearings before the House Committee on Interstate and Foreign Commerce,* 80th Cong., 1st sess. (Washington, DC: Government Printing Office, 1947), p. 557. For Senate testimony, see *Amendments to the Natural Gas Act, Hearings before the Senate Committee on Interstate and Foreign Commerce,* 80th Cong., 1st sess. (Washington, DC: Government Printing Office, 1947).

corporations.

With the only opposition being from the alternate-fuel and manufactured-gas interests, section 7(h) was added to the NGA on July 25, 1947, to give federally certified pipelines eminent-domain rights for pipeline and adjacent-facility right-of-way.[112] While a victory for the interstate industry, especially prospective lines, condemnation would lower costs and thus reduce the rate base on which margins applied. In any case, states such as Arkansas, Wisconsin, and Nebraska did not allow condemnation in their areas despite the rights conferred by federal certification.[113]

Eminent domain did *not* come with the obligation of common carriage, which potentially could have raised havoc for interstate pipelines externally financed on the strength of long-term contracts with producers and end-users. Section 28 of the Federal Lands Leasing Act of 1920, however, stated that right-of-way grants by the Department of the Interior had to be "under the express condition that such pipelines shall be constructed, operated and maintained as common carriers."[114] The U.S. Circuit Court of Appeals upheld this requirement for natural-gas pipelines in 1948.[115] In 1953, section 28 was amended to remove the common-carriage requirement where other municipal, state, or federal regulation was present.[116]

Legislative attempts in the 1950s to extend eminent domain to storage projects to join pipelines and compressor equipment failed.[117] In 1974, however, it was ruled in federal district court that certificated firms could invoke eminent domain to acquire underground facilities to store natural gas as well.[118]

Hinshaw Exemption: 1954. The next major change to the NGA occurred when section 1(c) was added to exempt local distribution companies (LDCs) from federal regulation. The problem of "dual regulation" occurred when an LDC either built a "stub line" from the city gate to connect with an interstate or purchased gas for resale to another LDC or municipality. Both practices placed LDCs as natural-gas companies under the NGA, which resulted in costly federal filings in addition to state filings.

Beginning in 1947, state public-utility commissions lobbied Congress to exempt LDCs from federal oversight. When a 1950 Supreme Court decision[119] required federal jurisdiction over LDCs connected in interstate commerce or performing sales for resale, the FPC and National

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[112] Pub. L. 80-245, 61 Stat. 459 (1947).

[113] See William Mogel and John Gregg, "Appropriateness of Imposing Common Carrier Status on Interstate Natural Gas Pipelines," *Energy Law Journal* 4 no. 2 (1983): 172–73.

[114] Pub. L. 66-146, 41 Stat. 449 (1920).

[115] *Montana-Dakota Utilities Co. v. Federal Power Commission,* 169 F.2d 392 (8th Cir. 1948), cert. den. 315 U.S. 95 (1948).

[116] Pub. L. 83-253, 67 Stat. 557 (1953).

[117] Robert McGinnis, "Some Legal Problems in Underground Gas Storage," in *Proceedings of the Seventeenth Annual Institute on Oil and Gas Law and Taxation* (New York: Matthew Bender, 1966), p. 70.

[118] *Natural Gas Pipeline Co. of America v. Iowa State Commerce Commission,* 369 F. Supp. 156 (D.C., S.D. Iowa, 1974).

[119] *Federal Power Commission v. East Ohio Gas Company,* 338 U.S. 464 (1950).

Association of Railroad and Utilities Commissioners went to work to amend section 1 of the Federal Power Act.

In House hearings in 1953, various states documented the millions of dollars of costs, passed through to consumers, associated with federal filings.[120] "Of perhaps more importance," added one state commissioner, "are the delays incident to securing necessary approvals of the Federal Power Commission on matters such as extensions of gas facilities, changes or revisions in rates, in financing requirements of the utilities."[121]

The only opposition to the exemption came from congressmen who felt that a move away from federal regulation was a bad precedent.[122] But with the cost and time advantages of removing dual regulation, H.R. 5976 was passed by Congress and signed into law by President Eisenhower on March 27, 1954.[123] Named after its House sponsor Carl Hinshaw (D-Calif.), the Hinshaw amendment was the bone given to gas producers in the wake of legislative and judicial setbacks to attempts to exempt field activities from federal regulation.

Industrial Sales-for-Resale: 1962. Since 1938, section 4 of the NGA had exempted sales for resale to industrial users from the Natural Gas Act. Only sales for resale in interstate commerce to residential and commercial users were subject to review, suspension, and refund by the commission. As industrial sales for resale became more important, sentiment surfaced to expand NGA regulation for the first time since 1942.

The FPC began lobbying for comprehensive sale-for-resale regulation in 1951.[124] In congressional hearings in 1961 and 1962, the Midwest Industrial and Commercial Gas Users Association lobbied for its pro rata share of rate refunds from Cities Service Gas Company (estimated at $2 million between 1954 and 1961 alone).[125] The National Coal Association advocated closing "a serious gap" in regulation to make sure industrial rates represented a "fair share of the costs of pipeline operations" to "eliminate the incentive which now exists to divert gas to inferior uses."[126]

In contrast, the American Gas Association opposed the amendment, stating "industrial rates

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[120] *Natural Gas Act* (*Distribution*), *Hearing before a Subcommittee of the House Committee on Interstate and Foreign Commerce,* 83rd Cong., 1st sess. (Washington, D.C.: Government Printing Office, 1953), pp. 29, 34–35, 43, 47, 58.

[121] *Natural Gas Act (Distribution),* p. 29.

[122] See, for example, *Congressional Record,* July 30, 1953, pp. 10563–65.

[123] Pub. L. 83-323, 68 Stat. 36 (1954). FPC Order 173, "Application for Exemptions from Provisions of the Natural Gas Act Pursuant to Section 1(c) Thereof," moderately reduced the backlog of cases that had worsened with the advent of producer price regulation. Federal Power Commission, *Order 173, Part 152—Application for Exemption from the Provisions of the Natural Gas Act Pursuant to Section 1(c) Thereof*, 19 Federal Register 4276 (July 13, 1954).

[124] Federal Power Commission, *Thirty-first Annual Report* (Washington, DC: Government Printing Office, 1951), p. 144.

[125] *Natural Gas for Resale for Industrial Use, Hearing before a Subcommittee of the House Committee on Interstate and Foreign Commerce,* 87th Cong., 2d sess. (Washington, D.C.: Government Printing Office, 1962), pp. 10–12.

[126] *Natural Gas for Resale for Industrial Use,* p. 24.

are competitive."[127] Columbia Gas Systems found such industrial regulation "not objectionable" since it was a small part of their operations.[128] In fact, no interstate company, not even Cities Service with the most at stake, took a negative position.[129]

On May 21, 1962, the FPC received its desired authority to regulate interstate sales for resale to industrial users.[130] This increased the range of intervenors and stakes for all parties to discourage, delay, modify, or prevent a rate change. This left direct sales to industrial users (with the pipeline receiving a carriage fee only) as the only "gap" in interstate regulation. The FPC favored this expansion of authority, too, but the necessary constituency was not there to enact it.

Public-Utility Regulation

Revenue Pool. The pool of revenue a firm is allowed under public-utility regulation is the sum of its cost of service and capital return. Costs deemed by authorities to have been prudently incurred are passed through to consumers, and firms are allowed a rate of return on valued capital—the rate base. Within a broad legislative mandate for just, reasonable, and nonpreferential rates, the methodology of calculating the revenue pool has evolved from administrative practices and judicial instruction since the last century.

A fact of business life is that costs must be passed through (recovered) to have an ongoing concern. In public-utility regulation, costs deemed reasonable and necessary for the proper conduct of business are eligible for recoupment. "Unreasonable" outlays cannot be passed through in rates and instead represent a charge to utility investors.

Of the areas of allowable cost, tax expense is relatively straightforward—the sum of local, state, and federal taxes. Common categories are income taxes, property taxes, gross receipt taxes, sales or use taxes, license or franchise taxes, public-utility taxes, and, where paid by the first purchaser, severance and production taxes. The dollar-for-dollar passthrough is interrupted only by rate change delays.[131]

Depreciation, calculated pursuant to a standard formula in the Uniform System of Accounts, is also a standard passthrough.[132] Calling for greater judgment on the part of regulators are

[127] *Amendments to the Natural Gas Act, Hearings before the Senate Committee on Commerce,* 87th Cong., 1st sess. (1961) (Washington, DC: Government Printing Office, 1962), p. 171. The American Petroleum Institute and other oil interests took no position. *Amendments to the Natural Gas Act, Hearings* (1961), p. 135.

[128] *Amendments to the Natural Gas Act, Hearings (*1961), p. 186.

[129] Of the 100 interstate firms subject to NGA regulation, only 10 separated out their industrial sales to escape commission control. And of these ten, some firms voluntarily gave refunds to industrial customers along with residential and commercial users. *Amendments to the Natural Gas Act, Hearings* (1961), pp. 4–6, 9.

[130] Pub. L. 87-454, 76 Stat. 72 (1962).

[131] John Holtzinger and Helen Paeffgen, "Taxes Other Than Income Taxes," in *Regulation of the Gas Industry,* 3 vols. (New York: Matthew Bender for the American Gas Association, 1981), vol. 2, chap. 27. The Louisiana First-Use Tax of $0.07 per thousand cubic feet, which was passed through by pipelines from 1978 to 1981, was declared unconstitutional and refunded to utility customers.

[132] For a discussion of allowed depreciation rates and historical controversies, see N. Knowles Davis, "Depreciation, Depletion, and Amortization," in *Regulation of the Gas Industry*, 3 vols. (New York:

determinations of reasonable operating expenses.[133] The greatest expense for gas pipelines, gas-acquisition costs, must be the result of arm's-length transactions to be passed through as a cost of service. Under wellhead price controls, the regulated price would be the passthrough allowable.

When price escalations became routine in the 1970s, a purchased-gas adjustment provision was adopted to facilitate rate increases without laborious rate filings.[134] Later in the decade, purchased-gas-adjustment rate alterations were limited to twice per year. In the early 1980s, with the take-or-pay predicament encouraging higher priced gas to be acquired instead of lower cost gas, the FERC introduced a "fraud and abuse" standard to discourage purchases at "excessive" prices.[135]

Other operating and maintenance expenses such as executive salaries, wages, pension contributions, rental expenses, transportation costs, and plant maintenance expenses are accepted at face value unless they are flagrantly high. Explained the Supreme Court,

> The Commission is not the financial manager of the corporation and it is not empowered to substitute its judgement for that of the directors of the corporation; nor can it ignore items charged by the utility as operating expenses [if] there is an abuse of discretion ... by the corporate officers.[136]

Subject to scrutiny as potentially "unreasonable" are charitable donations, advertising expenses, and research, development, and demonstration costs.[137]

A firm's cost of service is taken for a test period, generally the most recent twelve months when the information is available, with reasonably estimated changes when the final rate determination will apply. Cost regulation applies to jurisdictional costs only; revenues and expenses associated with nonregulated activities are separated before jurisdictional cost passthroughs are calculated.

The *rate base* is an estimate of the company's worth to which a rate of return is applied to arrive at the total profit a firm is allowed over cost. Because economic value is subjective, not objective, this determination is not simple. As economist Alfred Kahn has noted, "Its determination has been by far the most hotly contested aspect of regulation, consuming by far

Matthew Bender for the American Gas Association, 1981), vol. 2, p. 28.

[133] This discussion is taken from John Stough and Helen Paeffgen, "Allowable Operating Expenses," in *Regulation of the Gas Industry*, 3 vols. (New York: Matthew Bender for the American Gas Association, 1981), vol. 2, chap. 26.

[134] Federal Power Commission, *Order 452,* 47 FPC 1049 (1972); *Order 452-A,* 47 *FPC* 1510 (1972); and *Order 13,* 43 *Fed. Reg.* 50167 (October 27, 1978).

[135] Federal Energy Regulatory Commission, "Fraud and Abuse Standard," 47 *Fed. Reg.* 6253 (February 11, 1982).

[136] Southwestern Bell Telephone Co. v. PSC of Missouri, 262 U.S. 276 at 289 (1923).

[137] While informational and conservation advertisements have continued to be allowed, promotional and goodwill messages became victims of the 1970s gas shortage. Research, development, and demonstration costs have included controversial "quick-fix" projects undertaken to increase gas supply. See this chapter, pp. 930–31, and chapter 10, pp. 580–83.

the greatest amount of time of both commissions and courts."[138]

When federal regulation began in the 1930s, the FPC inherited the fair-value doctrine first established by the Supreme Court in 1898 for state regulatory commissions. In denying the exclusive use of original cost, desired by investors and regulated firms to increase valuation in a period of deflation, Justice John Harlan defined "fair value" as

> the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, [and] the present as compared with the original cost of construction.... What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.[139]

Thus, a middle figure between original cost and reproduction cost was made a constitutional requirement to avoid "the taking of private property for public use without just compensation or without due process of law."[140]

Unlike regulation of interstate oil pipelines, which from 1934 to the 1970s applied fair-value valuation by the Interstate Commerce Commission, FPC regulation of gas pipelines tended toward a more stringent valuation methodology. Under the NGA, the commission was given authority to "investigate and ascertain the actual legitimate cost of property of every natural-gas company."[141]

"Legitimate" was interpreted by the FPC to mean the *original cost* of gas reserves owned by interstate transmission companies beginning in the early 1940s. This radically understated the value of producing gas properties, and in 1942, Natural Gas Company of America brought suit against the FPC to substitute fair value for original cost for determining just and reasonable prices. Rejecting the challenge, Justice Stone opined for the Supreme Court:

> The Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas. Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make pragmatic adjustments which may be called for by particular circumstances. Once a fair hearing has been given, prior findings made and other statutory requirements satisfied, the courts cannot intervene in the absence of a clear showing that the limits of due process have been overstepped. If the Commission's order, as applied to the facts before it and viewed in its entirety, produces no arbitrary result, our inquiry is at an end.[142]

[138] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions,* 2 vols. (New York: John Wiley & Sons, 1970), vol. 1, p. 36.

[139] Smyth v. Ames, 169 U.S. 466 at 547 (1898).

[140] Smyth v. Ames, 169 U.S. 466, at 523.

[141] Natural Gas Act of 1938, Pub. L. 75-688, ch. 556, § 5(a), 52 Stat. 821, 824 (June 21, 1938).

[142] Federal Power Commission v. Natural Gas Pipeline Co. of America, 315 U.S. 575, 586 (1942). In a concurring opinion, Justices Black, Douglas, and Murphy plainly recognized the importance of the majority decision: "While the opinion of the court erases much which has been written in rate cases during the last half century, we think it is an appropriate occasion to lay to rest the ghost of *Smyth v. Ames,* 169 U.S. 466, which has haunted utility regulation since 1898" (at 602). The repudiation of fair value was

This decision opened the door for the "prudent investment" or "actual legitimate cost" methodology, which valued the firm at actual gross monetary outlays less depreciation (depletion) plus working capital.

A further burial of fair value was given two years later in the *Hope* decision by Justice Douglas, who espoused an "end result" or "capital attraction" criterion of just and reasonable rates to balance consumer and investor needs.

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends of the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[143]

In dissent, Justices Frankfurter and Jackson decried the strict valuation of the Court. Frankfurter argued that the method of calculation should be open to judicial review case by case and that the "total public interest," embracing future consumers as well as current consumers, was not served by the majority's guidelines.[144] Justice Jackson took original cost to task by emphasizing how gas properties were different from a pipeline's physical facilities given that the high-risk characteristics of exploration made discovery cost well below market value.[145]

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It would not be until the highly inflationary 1970s that depreciated original cost would come under judicial review. The interventionist bias of federal regulators and the courts, combined with industry growth that seemingly vindicated stringent valuation, explained the longevity and survival of the original-cost methodology. Another reason for its survival was the ability of firms to replenish the rate base with new investments as traditional investments "vanished" from depreciation. Many of these "replenishment" projects were not prudent on a stand-alone basis and, in retrospect, were fiscal blunders.[146] Inflation, in any case, would be accounted for in the rate of return.

The original-cost versus replacement-cost controversy was resurrected in the 1970s with oil pipelines. As seen in the last chapter, the FERC was instructed by the judiciary to value oil pipelines toward original cost instead of a combination of original and reproduction cost—

reaffirmed in Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944), and by the FPC in the 1960 *Panhandle Eastern Pipe Line Co.* case, 23 FPC 352.

[143] Federal Power Commission et al. v. Hope Natural Gas Co., 320 U.S. 591 at 603 (1944). Justice Douglas three decades later would similarly argue that just and reasonable rates required that "the financial health of the pipeline in our economic system remains strong." *Federal Power Commission v. Memphis Light, Gas, & Water Division,* 411 U.S. 458 at 474 (1973).

[144] Federal Power Commission et al. v. Hope Natural Gas Co., 320 U.S. 624–28 (1944).

[145] Federal Power Commission et al. v. Hope Natural Gas Co., 320 U.S. 624–28 (1944).

[146] See this chapter, pp. 929–31.

another repudiation of "fair value."[147]

Under either original cost or fair value, a "fair" rate of return is applied to derive profit. This return, summed with the firm's cost of service, is apportioned over the anticipated throughput of the pipeline to calculate individual pipeline tariffs.

The rationale and guiding principle of determining the rate of return were stated by the Supreme Court in 1923.

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.[148]

Continuing in the language that Justice Douglas would rediscover two decades later in his "end result" doctrine.

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[149]

In the first decade of federal regulation, allowed returns ranged from 6 to 6.5 percent.[150] Challenges to the yardstick seeking higher returns in 1944 (*Hope*) and 1945 (*Colorado Interstate*) were rebuffed by the Supreme Court.[151]

In 1952, a new methodology temporarily eclipsed the percentage-return approach. In the *Northern Natural Gas Company* case, the FPC unveiled the "cost-of-money" approach, which computed a 5.5 percent return. This was the first time under the NGA that a firm was allowed under 6 percent.[152] A manifestation of the end-result doctrine, this methodology weighted the average of the firm's contractual debt (bank loans and bonds) and equity.[153]

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[147] See chapter 14, pp. 828–29.

[148] Bluefield Water Works and Improvement Co. v. Public Service Commission, 262 U.S. 679, 692–93 (1923).

[149] Bluefield Water Works, 262 U.S. at 693 (1923).

[150] Owen Ely, "Gas Industry Worries over FPC's 'Cost of Money' Rate Theory," *Public Utilities Fortnightly,* November 20, 1952, p. 795.

[151] Marcus, *National Government and the Natural Gas Industry*, pp. 168, 173.

[152] "In the Matter of Northern Natural Gas Company," Federal Power Commission, Opinion No. 228, 11 FPC 123 (1952).

[153] A hypothetical example of computing a 5.6 percent cost-of-money allowance is:

Type	Amount	% of Total	Rate	Weighted Cost
Bank debt	$1,000,000	0.20	8%	1.6%
Bond	2,000,000	0.40	6	2.4
Equity	2,000,000	0.40	4	1.6
		1.00%		5.6%

A year later, a slightly liberalized cost-of-money formula resulted in a 6.25 percent return for the United Fuel Gas Company.[154] The new procedure tightened the regulatory clamp by lowering returns in some cases, increasing hearing costs for the firm, and prolonging the "locked-in" period for disputed rates. By January 1954, a backlog of forty-nine cases with $143 million in dispute resulted from the new return methodology.[155]

The cost-of-money approach became standard in the 1950s, providing a steady 6 percent return corresponding to steady borrowing costs and dividend rates.[156] The standard return, however, did not affect firms equally. Companies with high debt-to-equity capitalizations realized higher common-equity returns than low debt-to-equity companies because of favorable tax implications for the former.[157] This bias was exacerbated in the early 1960s when the FPC gave debt-intensive firms a return premium to compensate for the greater risk of having more fixed costs to cover.[158]

In the 1960s, despite escalating inflation, returns remained at 6 to 6.5 percent on net investment, a 10 to 12 percent equity return.[159] As late as 1968, the commission stubbornly refused to consider inflation in the return calculation. In one ruling, an inflation allowance was equated to fair-value ratemaking and rejected.[160] A second case the same year left the return calculations intact on grounds that "an assumption that an inflationary spiral will continue ... would be pure speculation."[161]

By the early 1970s, the FPC recognized inflation as a "present fact of life.... Its effects on cost must be acknowledged."[162] Similar judgments followed, and in a 1976 opinion, strong language was used to declare a break from the past to account for inflation:

> The pendulum has definitely swung in a direction substantially contrary to the interests of the investor. A time of adjustment is clearly called for.[163]

Higher rates of return, however, would not be automatic; the firm had to demonstrate why the adjustment was necessary for the public interest to be served.[164] Record high rates of return

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[154] In the Matter of the United Fuel Gas Company, FPC Docket G-1781 and G-2055, Opinion 258 (August 7, 1953); affirmed on rehearing, Opinion 258A (November 19, 1953).

[155] Owen Ely, "The FPC Backlog of Gas Rate Cases," *Public Utilities Fortnightly,* January 21, 1954, p. 107. Field regulation of natural gas would add to the backlog problem.

[156] Walter Gallagher, "Rate of Return," in *Regulation of the Gas Industry*, 3 vols. (New York: Matthew Bender for the American Gas Association, 1981), vol. 2, p. 30-55.

[157] Debt costs, unlike dividend payments, are expensed from gross income. By lowering taxable income, debt reduces the net cost of capital, which increases profit as a percentage of capital.

[158] In 1956, the FPC first tied the rate of return to a firm's capitalization. In 1962, a higher return was allowed for debt-intensive El Paso Natural Gas (Opinion 366), 28 FPC 688, and in 1968 for similarly leveraged Panhandle Eastern (Opinion 543), 40 FPC 98. Walter Gallagher, "Rate of Return," pp. 30-55 to 30-56.

[159] Walter Gallagher, "Rate of Return," p. 30-89.

[160] Opinion 543-A, 40 FPC 452 (1968).

[161] Opinion 543, 40 FPC 98 at 110 (1968).

[162] Opinion 659, 49 FPC 1154 at 1182 (1973).

[163] Opinion 769, 56 FPC 120 at 139 (1976).

[164] See, for example, 10 FERC 61041 (1980).

were granted by the FERC in the inflationary 1975–80 years.[165]

The allowed return is not a maximum rate or a guaranteed rate of profit. To some extent, profit is assured by entry restrictions (certification) and distribution franchises that make demand less sensitive to price. But actual returns can be below the maximum allowed. In such cases, unused returns cannot be carried forward to obtain a premium return in a future period; similarly, an above-maximum return from hidden rate-case opportunities cannot be balanced by a submaximum return in a future year.

Rate Structure. Prior to the Natural Gas Act, interstate pipeline firms entered into tailored agreements with local distributors and large industrial customers.[166] With an eye to overall profitability, pricing was determined according to demand sensitivity, with some customers valued for their contribution to fixed costs and other customers serving as profit makers because their rates covered fixed costs and more. (All purchasers paid rates above variable costs.)

With the enactment of the NGA in 1938, rates were consolidated to conform to the just, reasonable, and nondiscriminatory provisions of the act. In 1940, the FPC released instructions to convert the myriad of contracts to system-wide tariffs. This was interrupted by wartime, and in 1948 the commission published a Tariff-and-Service Agreement form from which all firms were in compliance by 1950.[167] The agreements spelled out all service terms and conditions but left price as a variable. Without the flexibility to make long-term, fixed-price contracts, firms set short-term rates that could be changed with a new cost-of-service filing or commission decision.

Within the confines of nondiscriminatory pricing, assignment of variable cost was not difficult. Each customer would pay according to his physical consumption of gas. Fixed cost, however, which constituted between 80 and 90 percent of pipeline cost at the time, was judgmental. The choices were to assign fixed cost proportionally with variable cost or to skew fixed costs toward peak-demand users. The rationale of the latter approach was that idle capacity of natural-gas pipelines during off-peak periods (the summer in most markets) was the cost of providing peak, uninterrupted service to these customers, and they should pay for associated fixed costs.

Prior to regulatory instruction, the practice developed of allocating fixed cost toward customers with the highest peak demand and charging proportionately less to customers whose demand alone would have required less pipeline capacity (less fixed cost). In 1952, an FPC formula allocated 50 percent of the demand charge to the *demand* (firm service) component of sales and 50 percent to the *commodity* (volume) component of sales.[168]

Compared to the prior approach, interruptible (nonpeak) customers paid more and

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[165] See the return figures provided in Walter Gallagher, "Rate of Return," pp. 30-90 to 30-91.

[166] This discussion is taken in part from Paul Garfield and Wallace Lovejoy, *Public Utility Economics* (Englewood Cliffs, N.J.: Prentice-Hall, 1964), p. 178.

[167] *Order 144,* 13 *Fed. Reg.* 6371 (October 30, 1948).

[168] Atlantic Seaboard Corp., 11 FPC 43 (1952).

noninterruptible (peak) customers paid less. A detrimental consequence was to send nonpeak customers toward coal and fuel oil. This forced the commission to make pragmatic adjustments toward the pre-1952 formula to avoid load loss in some cases.[169] Thus, it was not surprising that "coal interests are the staunchest supporters of the *Atlantic Seaboard* formula."[170]

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For over two decades the *Atlantic Seaboard* formula held sway, with certain exceptions. In 1973, a new formula received FPC sanction that tilted 75 percent of fixed cost to the commodity side.[171] The *United* formula was biased in favor of residential and commercial (peak) users at the expense of major industrial (nonpeak) users. The commission rationalized that average pipeline utilization would increase from this rate design.[172]

The political roots of the 75/25 percent apportionment were evident in Title II of the Natural Gas Policy Act of 1978, which instructed higher gas prices to be funneled toward industrial users to shield smaller users from higher fuel costs.[173] The unintended consequence, as before, was interfuel substitution away from gas, leaving captive customers with more fixed costs to shoulder. Exceptions to the *United* formula were made to place fixed cost on the demand component, such as the *Northern Border Pipeline* decision.[174]

With gas oversupply and load problems on interstate pipelines, flexible rate designs based on market-clearing considerations began to be introduced in 1983 and 1984.[175] In addition, Phase II of incremental pricing, intended to extend requirements from large industrial facilities to all industrial customers, was postponed and finally revoked by the FERC in March 1984.[176]

The FPC also changed how geographical pricing was determined in relation to the pipeline supply source. An early commission dictum was, "In the absence of compelling reasons to the contrary, it is good and desirable practice to fix rates that are uniform."[177] The question arose whether equity implied uniform "postage-stamp" rates for customers or whether equality meant tiered prices progressively rising for distant customers.

A 1955 decision by the FPC replaced uniform pricing with a three-zone system for the 600-

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169 Alfred Kahn, *The Economics of Regulation,* vol. 1, p. 99. For specific cases of demand component "tilting," see Francis Quinn and Cheryl Foley, "Pipeline Rates," *Regulation of the Gas Industry,* 3 vols. (New York: Matthew Bender for the American Gas Association, 1981), vol. 2, pp. 35-15 to 35-16.

170 Paul Garfield and Wallace Lovejoy, *Public Utility Economics,* p. 184.

171 United Gas Pipe Line Co., Opinion 671, 50 FPC 1348 (1973), aff'd.; *Consolidated Gas Supply Corp.* v. *FPC,* 520 F.2d 1176 (D.C. Cir. 1975).

172 Francis Quinn and Cheryl Foley, "Pipeline Rates," p. 35-10.

173 Pub. L. 95-621, 92 Stat. 3371.

174 11 FERC 61136 (1980).

175 See J. Richard Tiano and Richard Bonnifield, "The Impact on Gas Distribution Companies of Federally Approved Special Marketing Programs," *Energy Law Journal* 5, no. 2 (1984): 293–95.

176 49 *Fed. Reg.* 12207 (March 29, 1984).

177 In the matter of *City of Cleveland* v. *Hope Natural Gas Co.,* 3 FPC 150 at 190 (1942).

mile Northern Natural pipeline.[178] Customers nearer the supply source argued that they subsidized distant customers; Northern argued that load requirements of distant markets subsidized nearer customers by permitting scale economies associated with a larger diameter pipeline.

The zoning order also introduced thousand cubic feet-mile pricing into the *Atlantic Seaboard* formula. Other decisions went against zone pricing or mandated virtually identical prices geographically.[179]

Certification Issues. The FPC's Provisional Rules of Practice and Regulations under the Natural Gas Act became effective July 11, 1938. But it took a commission interpretation in the *Kansas Pipeline* (October 1939) case, recognized by Carl Wheat as "a milestone in the development of Federal Power Commission administration under the statute," to delineate certification powers under section 7(c).[180] The FPC decided that its certification powers (1) could only be established on a factual case-by-case basis, (2) would cover "an area or territory of undefined extent bearing some reasonable relation to existing pipelines" (versus strips of land representing present occupation), and (3) did not encompass end-use considerations.[181]

The decision also provided guidelines specifying conditions for entry certification. The firm had to demonstrate

1. adequate financial resources to complete the project and become operational;
2. adequate demand for its service;
3. adequate supply to meet demand;
4. "full and complete" service; and
5. "adequate and reasonable" costs and rates.[182]

Reflecting the competitive language in the act, the commission concluded,

> Where there is not existing natural-gas service the convenience and necessity of the public ... will be served by the introduction of that service provided that those who seek to render that service can meet certain minimum standards designed to secure such service on a continuous and adequate basis.[183]

These conditions applied to all firms entering the market in occupied areas or not, which would bring complications. From 1940 to 1946, such matters were moot because of wartime steel shortages that postponed projects. With the resumption of entry in 1947 and universal certification, a trend began that has continued to this day—increasing complexity to satisfy

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[178] Northern Natural Gas Co., 9 PUR 3d 8 (1955). See the discussion in Paul Garfield and Walter Lovejoy, *Public Utility Economics,* pp. 186–87.

[179] See, for example, Michigan Wisconsin Pipe Line Co., Opinion 471, 34 FPC 621 (1965).

[180] Carl Wheat, "Administration by the Federal Power Commission of the Certificate Provisions of the Natural Gas Act," *George Washington Law Review* 14, no. 1 (December 1945): 197.

[181] Kansas Pipe Line & Gas Co. et al., 2 FPC 29 (1939).

[182] See John Cheatham, "Regulation in the Post–World War II Period," in AGA, *Regulation of the Gas Industry,* vol. 1, pp. 4-13 to 4-16.

[183] Kansas Pipe Line & Gas Co., 2 FPC 29 at 56 (1939).

entrance requirements. Noticed John Cheatham:

> Since World War II numerous changes have been made to certification regulations ... and generally these changes have required more data and details. As a result, a certificate application, with the necessary exhibits appended thereto, can now run into multiple volumes and thousands of pages.[184]

Interfirm competition was intended by the NGA despite the fact that proposals by interstates to enter occupied areas required hearings with the burden of proof on the potential entrant. In 1939, the FPC "began to give form to Congress' directive"[185] for nonexclusive territory by licensing the Louisiana-Nevada Transit Company to build a pipeline in the defined "market area" of the Arkansas-Louisiana Gas Company because of proposed lower rates.[186] A second decision two years later reaffirmed direct competition when Gas Transport, Inc. was certified to purchase and operate an unfinished gas-pipeline project in a market served by Hope Natural Gas in the interest of rate competition.[187]

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Amendments to the NGA in 1942 retained the commission's authority to deny exclusive territorial rights to a firm (which was soon exercised)[188] but extended the certification requirement to all entrants with a grandfather clause for established firms. The question of whether this clause would block entry in an occupied market was partly decided in March 1947 when the FPC awarded a certificate to the Michigan-Wisconsin Pipe Line Company to construct a line to Detroit, which hitherto had been exclusively served by Panhandle Eastern.[189]

Detroit's demand for gas, however, did not present an either-or for the two firms; Michigan-Wisconsin was certified to serve the "growth load" above the capacity of Panhandle's line. Nonetheless, an important limitation was placed on grandfather rights. In the commission's words:

> It seems clear that any privileges conferred by a grandfather certificate issued under the Natural Gas Act should not, as a matter of law, be extended beyond "substantial parity" with the operation, service, transportation, or sale actually performed on February 7, 1942. It follows that any additional operation ... not clearly covered by an existing grandfather certificate must be approved by a

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184 John Cheatham, "Regulation in the Post–World War II Period," p. 4-16. Regulations pertaining to section 7 of the NGA run over fifty pages, requiring (sec. 157.5) "all information necessary to advise the Commission fully concerning the operation, sales, service, construction, extension, or acquisition for which a certification is requested or the abandonment for which permission and approval is regulated." See AGA, *Regulation of the Gas Industry,* vol. 4, p. 140-91.

185 Walter Gallagher, "Rate of Return," p. 30-22.

186 Louisiana-Nevada Transit Co., 2 FPC 546 (1939).

187 Gas Transport, Inc., 2 FPC 1079 (1941).

188 Hope Natural Gas, 4 FPC 59 (1944). The argument of intervening coal and railroad interests—that a second pipeline represented an inferior use of gas—was rejected.

189 Michigan-Wisconsin Pipeline Co., 6 FPC 1 (1947).

non-grandfather certificate.[190]

To the disappointment of established interstate pipelines, the protection envisioned from the 1942 amendments was confined to existing market share.

In the 1960s, entry applications for solely occupied areas significantly increased, which led to several opinions that better defined the FPC's view of head-to-head rivalry. Of $1.4 billion in proposals as of June 30, 1965, $1.1 billion was for occupied areas with the balance for virgin territory.[191]

In keeping with its 1947 decision and the competitive language of the act, a series of FPC decisions in 1967 showed a clear preference for multifirm competition and low prices over certification protection. Stated the commission, "A monopoly ... should not be automatically and consistently protected where it is demonstrated that competition would produce greater benefits to the public."[192]

In 1967, the commission awarded a certificate to Texas Gas Transmission to pipe the supply previously moved by the Fuel Gas Company to Hamilton, Ohio, by virtue of better consumer service.[193] In the same year, Transcontinental Pipeline was awarded a certificate to sell gas to distributors in Washington, D.C., and northern Virginia despite a plea from the Atlantic Seaboard Corporation, sole supplier to the area, that Transco's entrance would destabilize its operation.[194] In another 1967 case, a distributor was allowed to switch pipeline suppliers to take advantage of lower rates.[195]

Thus, after twenty years, area competition was confirmed with new entrants allowed to capture market growth. The FPC had let it be known that no existing market niche was immune from competition. But with the burden of proof on entrants and two decades of doubt, a strong anti-competitive legacy had been created that would continue.

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Two other important FPC cases defined interfirm competition. Again in 1967, the commission initiated a section 7(a) proceeding to order Tennessee Gas to service Hartford, Connecticut, despite the fact that Algonquin Gas Transmission had applied for the extension.[196] While Tennessee's cost estimate for servicing Hartford was below Algonquin's, the unprecedented order was made to balance earlier decisions that leaned toward territorial rights on the rationale that two firms in a market were more competitive than one, even if

[190] Dissenting from this view in favor of quasi-franchise rights for established firms were the supposed consumer advocates, Commissioners Olds and Draper. "Limitations on Grandfather Rights Defined in FPC Opinion," *OGJ,* March 15, 1947, p. 132.

[191] John Cheatham, "Regulation in the Post–World War II Period," p. 4-20.

[192] Columbia Gulf Transmission Company et al., Opinion 512, 37 FPC 118, at 130 (1967).

[193] City of Hamilton, Ohio, et al., Opinion 513, 37 FPC 209 (1967).

[194] Columbia Gulf Transmission Company et al., Opinion 512, 37 FPC 118 (1967).

[195] Alabama-Tennessee Natural Gas Company et al., Opinion No. 534, 38 FPC 1069 (1967). Aff'd *Alabama-Tennessee Natural Gas Co. v. Federal Power Commission,* 417 F.2d 511 (5th Cir. 1969). Also see Alfred Kahn, *The Economics of Regulation,* vol. 2, pp. 166–67.

[196] Algonquin Gas Transmission Company et al., Opinion 522, 37 FPC 1128 (1967).

created by edict.[197]

In the late 1960s, a second illustrative proceeding decided which of three applicants, if not all, could meet the burgeoning demand of the southern California market. This market had been served by El Paso Natural Gas since 1946 and Transwestern since 1960, and both firms applied for expansions. A paper subsidiary of Tennessee Gas, Gulf Pacific Transmission Company, wanted to build an entirely new line.

In 1958, the FPC had denied an expansion by El Paso on grounds that gas demand was inadequate and the anticipated cost too high. But use of fuel oil in place of natural gas was contributing to the area's worsening air-pollution problem, which gave new impetus for increased pipeline capacity to the state.

In 1968, the commission ruled against Gulf Pacific because "trends in nuclear energy, the development of remote coal-fired steam electric plants, and the build up in [extra-high-voltage] interregional interests will minimize the need for additional generation in Los Angeles county."[198]

This decision would lead to second-guessing. With gas-supply curtailments in California in the mid-1970s, the ability of El Paso and Transwestern to satisfy demand was open to question; with dedicated reserves in tow, Gulf Pacific could have helped to bridge the gap, although partly at the expense of pipelines in other areas, given widespread shortages in interstate markets.

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The prize of certification was also coveted by firms entering unserviced areas. In the late 1930s, Tennessee Gas and Transportation Company was organized to secure financing for a gas pipeline from southern Louisiana to the Tennessee Valley. A certification application was made to the FPC on November 25, 1942, and a year later the War Production Board, cognizant of looming gas shortages in the Appalachian region, granted a steel allocation subject to FPC approval.[199]

With financing still a problem for Tennessee, Hope Natural Gas, a subsidiary of Jersey Standard, applied for a certificate to build a similar line commencing in the Hugoton field. Hope seemed the logical choice—financing was certain, it already had a line serving the targeted market, and its gas reserve base was strong. A day before hearings began on the

[197] Carl Bagge, "The Federal Power Commission," *Boston College Industrial and Commercial Law Review* 11, no. 4 (May 1970): 702.

[198] Transwestern Pipeline Company et al., Opinion 500, 36 FPC 176, at 191 (1966). (consolidated with Gulf Pacific Pipeline Co., a Tenneco/Tennessee Gas affiliate, and El Paso Natural Gas). For Tennessee Gas this marked the end of an eight-year battle to enter the southern California market that had begun with a proposed pipeline through Mexico. Not only was it the most expensive certification lobbying effort by one company, it had the intrigue of a spy thriller. There were a bugging episode, sneak legislation, secret informants, alleged bribes, and secret evidence and obstructionism in hearings. For a story of certification at its worst, see Richard Smith, "They Play Rough in the Gas Business," *Fortune,* January 1966, pp. 132–35, 230–33.

[199] An earlier application in 1940 was dismissed for want of jurisdiction, which meant certification was not required in unserviced areas.

Hope application, Tennessee's financing came through, and the commission orally awarded the exclusive franchise.[200]

Tennessee's time-consuming completion of its certification requirements and secure steel rations figured prominently in the decision, but politics was also involved. "The company had more political than financial clout," noted Arlon Tussing and Connie Barlow. "It had not yet acquired any physical assets, but its presiding officer was the former son-in-law of President Roosevelt."[201] In 1944, the Tennessee Gas pipeline, enlarged to 1,265 miles to stretch from the Texas Gulf Coast to Cornwall, West Virginia, was completed at a cost of $4 million.

In 1950, competing applications to serve the New England market were made by Tennessee Gas Transmission and Texas Eastern Transmission.[202] The two companies. not cordial, relentlessly pursued an exclusive franchise to supply a major new market. Eastern states already receiving gas protested against both applications on the grounds that the FPC should not certify any new applications until their waiting-list customers were serviced. A compromise certification gave Texas Eastern (Algonquin) exclusive rights to Connecticut, Rhode Island, and eastern Massachusetts, and gave Tennessee Gas a franchise to New York and remaining areas of Massachusetts.[203]

A mid-1970s certification tiff raised the level of complexity and delay to new heights. Three applications to transport natural gas from the Prudhoe Bay field in Alaska to the lower forty-eight states were submitted between March 1974 and July 1976—the Alcan Pipeline proposal to California, the Alaskan Arctic Gas Pipeline proposal to Illinois, and a tanker plan by El Paso to feed existing lines to California.

The FPC used technical economic analysis to determine the "Net National Economic Benefit" of each under a variety of assumptions. By the time the FERC inherited the stalemate in 1977, other branches of government had assumed jurisdiction over the decision. Finally, after U.S. officials narrowed the choice to two firms, the Canadian government chose the winner in mid-1977—Alcan.[204]

Another certification battle as of 1984 was between a $323-million Transcontinental Gas–Tennessee Gas–Texas Eastern proposal between Niagara Falls, New York, and Leidy, Pennsylvania, filed in January 1983, and an ANR Pipeline–Northern Natural 663-mile, $1-billion proposal between Ventura, Iowa, and Defiance, Ohio. Hearings on proposals to transport plentiful Canadian gas to the gas-poor Northeast began in 1985 with a resolution not

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[200] Tennessee Gas and Transmission Co., Opinion 575, 3 FPC 574 (1943). The certification was not only a setback for Hope but also for coal intervenors who were against gas per se—the National Coal Association, United Mine Workers, Anthracite Institute, Southern Appalachian Coal Operators' Association, and Railway Labor Executives Association. Louisiana, which desired state gas to remain in home markets, was also against the certification.

[201] Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* p. 42.

[202] This proceeding is also discussed in this chapter, pp. 936–37.

[203] *Tennessee Gas Transmission Company et al.,* Opinion 202, 9 FPC 271 (1950); and *United Gas Pipe Line Company et al.,* Opinion 206, 10 FPC 35 at 57 (1951).

[204] Further analysis of the regulatory issues surrounding Alaskan gas transportation is provided in this chapter, pp. 912–13.

expected for several years.

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The foregoing decisions do not reveal any set procedure for awarding certification. Early applicants were rewarded (Tennessee, 1943) as were later applicants (Texas Eastern, 1952). Subjectively perceived "merits of the case," not excluding political factors, seem to have been a major factor in FPC decisions between competing interstate pipeline proposals.

Coal-related unions, railroads, producers, and distributors, led by the National Coal Association, participated directly in the debate over the Natural Gas Act in the 1935–38 period. The same parties were instrumental in expanding certification to all interstate activity in 1942. With their participation rights secure, alternate-fuel interests intervened regularly in FPC hearings in the 1940s, 1950s, and early 1960s, eager to forestall displacement of coal by cost-competitive, clean-burning gas.[205]

Fuel-oil interests also actively opposed gas-pipeline licenses. As intervenors, they had to demonstrate that the public convenience and necessity were not served by displacement, which was argued first on *end-use* grounds—that gas as a premium fuel should not be used in "inferior" uses that relatively plentiful coal or fuel oil could meet—and second on grounds of employment and income loss from displacement. A third reason was championed by industry and utilities within gas-producing states who desired to retain gas in home markets to promote industrialization enjoyed by many gas-importing states.[206]

The original position of the FPC was that conservation and end-use considerations were outside of the certification process, which kept rival fuels at bay.[207] This September 1943 opinion was reversed less than a year later by the Supreme Court to give end-use material concern:

> When it comes to cases of abandonment or of extensions of service, we may assume that apart from the express exemptions contained in §7, considerations of conservation are material to the issuance of certificates of public convenience and necessity.[208]

Pursuant to this decision, the FPC released Docket G-508 calling for end-use evidence in future certification hearings. This opened the door for special interests threatened by natural-gas expansion.

On June 10, 1944, the first end-use decision denied certification to Memphis Natural Gas

[205] Testimony in the 1940s against a "free-trade" natural-gas policy was given by the National Coal Association, United Mine Workers of America, Railway Labor Executives' Association, Brotherhood of Locomotive Engineers, American Retail Coal Association, Anthracite Institute, and Operators of Coal Docks on Lake Michigan and Lake Superior. See, for example, Ralph K. Huitt, "Federal Regulation of the Uses of Natural Gas," *American Political Science Review* 46, no. 2 (June 1952): 455–69.

[206] Huitt, "Federal Regulation of the Uses of Natural Gas," pp. 460, 462–64.

[207] Tennessee Gas and Transmission Co., Opinion 575, 3 FPC 574 (1943). Also see "The First Five Years under the Natural Gas Act," *Federal Power Commission Report to the House Committee on Interstate and Foreign Commerce,* 78th Cong., 2d sess. (Washington, D.C.: Government Printing Office, 1944).

[208] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, at 612 (1944).

because gas sold for boiler fuel was not a "superior" use of the fuel. Upon rehearing, certification was granted to Memphis, which led Louisiana, favoring intrastate use, to unsuccessfully seek reversal by the circuit court of appeals.[209]

With the issue opened, coal interests in 1943 and 1945 sought to amend the NGA to "give due consideration ... to the conservation of natural gas resources, the adequacy of reserves and the social and economic effects of their depletion."[210] Although the majority of decisions would not go their way—indeed, a circuit court in 1951 ruled that while end use was an element to be considered in the complex of public convenience and necessity, it was not a determinative factor[211]—as late as 1959 the commission blocked an expansion of natural-gas service by New York's Consolidated Edison by ruling that gas use as a boiler fuel was "inferior."[212]

In subsequent years, the ability of rivals to fend off natural gas diminished; gas was too cheap, plentiful, nonpolluting, and free of labor risks compared with coal. Natural-gas shortages and regulatory responses pushed coal back into the picture in the 1970s, but for the same reasons, active gas expansion into new markets was not present for coal interests to counter.

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Section 7(a) of the NGA gave the FPC authority to order a firm to "extend or improve its transportation facilities or establish physical connection" to nearby distributors if "no undue burden" was placed on the firm's "ability to render adequate service to its customers."[213] This authority did not apply to enlargements constructed to handle load growth.

The first question under 7(a) was what constituted adequate service. Extensions to new areas could be stymied if the commission strictly interpreted the firm's obligation to its original clientele. In 1953, the court of appeals ruled that adequate service did not mean *full* service, defined as meeting demand in peak periods, and that extensions could be made short of this. Determination of "adequate service" was a factual matter to be decided case by case.[214]

A second case differentiated mandatory improvements from mandatory enlargements. In 1953, the FPC ordered Panhandle Eastern to eliminate customer discrimination by increasing the diameter of one of its pipelines. The order was reversed in circuit court; discrimination

[209] Also against certification were the National Coal Association, the United Mines Workers, and several railroad labor organizations; favoring certification were area gas distributors desiring lower prices, the Texas Railroad Commission, and the Independent Natural Gas Association of America. John Cheatham, "Regulation in the Post–World War II Period," p. 4-26.

[210] Carl Wheat, "Administration by the Federal Power Commission of the Certification Provisions of the Natural Gas Act," pp. 201–2.

[211] *National Coal Association* v. *FPC,* 191 F.2d 462 at 467 (D.C. Cir. 1951).

[212] *Transcontinental Gas Pipeline Corporation et al.,* Opinion 315-A, 21 FPC 138 (1959). The constitutionality of end-use considerations was reconfirmed by the Supreme Court in *Federal Power Commission v. Transcontinental Pipe Line Corp.,* 365 U.S. 1 (1961).

[213] Pub. L. 75-688, 52 Stat.821, at 824 (1938).

[214] *Manufacturers Light and Heat Co.* v. *FPC,* 206 F.2d 404 (3rd Cir. 1953).

notwithstanding, it was ruled that forced expansion violated section 7(a) of the NGA.[215]

In 1962, the FPC ordered Mississippi River Fuel to reallocate pipeline volume away from direct industrial customers to increase deliveries to residential customers through their gas distributor.[216] The circuit court reversed on appeal because Mississippi was not unambiguously meeting the "present and reasonably foreseeable requirements [of] existing lawful customers."[217] Mandatory reallocation of supply between customers, the court ruled, was not permitted under 7(a).

Another important 7(a) decision occurred in 1964 when the FPC ordered Tennessee Gas to physically connect a gas-distribution company located near one of its pipelines. Commissioner Carl Bagge justified the "extraordinary action" as necessary to promote "vigorous pipeline competition in the Northwest."[218]

Issues concerning mandatory extensions and improvements of service became a thing of the past when the cumulative effects of field-price regulation of natural gas precipitated supply problems and even shortages in interstate markets in the late 1960s and 1970s. In sharp contrast to the previous era of rapid expansion, interpretations under the NGA took a complete turn from service extensions and improvements to abandonment and curtailment of service.

Offshore, the issue of forced service remained alive. Section 603 of the Outer Continental Shelf Land Act was designed to facilitate offshore pipeline connections, and the FERC followed with a statement of policy that Outer Continental Shelf hookups could be compelled.[219] Guidelines were not specified; presumably future opinions and court decisions would delineate them.[220]

Section 7(b) prohibited jurisdictional firms from abandoning service to any certificated customer without a commission "finding" that "the present or future public convenience or necessity permit such abandonment."[221] If any party was opposed to the proposed service termination, formal hearings were necessary.

Termination clauses were not allowed in producer contracts. In the 1960 *Sunray* decision, a twenty-year certificate awarded by the FPC was found not to be a maximum period whereupon a producer could discontinue service but a certificate of unlimited duration.[222] The

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[215] *Panhandle Eastern Pipe Line Co.* v. *FPC,* 204 F.2d 683 (3rd. Cir. 1953).

[216] *Arkansas-Louisiana Gas Company et al.,* Opinion 355, 27 FPC 697 (1962).

[217] *Granite City Steel Co.* v. *Federal Power Commission,* 320 F.2d 711 (D.C. Cir. 1963).

[218] *Algonquin Gas Transmission Company et al.,* Opinion 522, 37 FPC 1128 (1967). See John Cheatham, "Regulation in the Post–World War II Period," pp. 4-8 to 4-9.

[219] "Statement of Policy on Outer Continental Shelf Gas," Order 92, 12 FERC 61069 (1980); and "Statement of Policy on Outer Continental Shelf Gas," Order 92-A, 13 FERC 61215 (1980).

[220] The law firm of Littman, Richter, Wright & Talisman, P.C., "Pipeline Service Obligations," in AGA, *Regulation of the Gas Industry,* vol. 1, p. 11-17.

[221] Pub. L. 75-688, 52 Stat. 821 at 824 (1938).

[222] Sunray Mid-Continent Oil Co. v. FPC, 364 U.S. 137 (1960). In a 1978 decision, the "perpetual dedication rule" was extended to cover expired leases on gas properties. California v. Southland Royalty Co., 436 U.S. 519 (1978).

Fifth Circuit gave the following analogy.

> Like the ancient covenant running with the land, the duty to continue to deliver and sell flows with the gas from the moment of first delivery down to the exhaustion of the reserve, or until the commission, on appropriate terms, permits cessation of service under Section 7(b).[223]

The NGA gave the FPC wide discretion to tailor certifications "that the present and future public convenience and necessity require."[224] The commission's latent authority to make allocation decisions was first used between 1947 and 1951 when seven opinions were issued dealing with capacity problems of Panhandle Eastern in the Detroit area.[225] Other than this isolated instance, government allocation was confined to certification decisions about which waiting-list customers would be served. The issue was not moot. Between 1949 and 1952, Congress debated legislation that would deny service to new areas until existing areas were fully hooked up.[226]

In 1952, the FPC included service curtailment in the abandonment-of-service category.[227] In two later decisions, the Supreme Court upheld the interpretation.[228] Beginning in November 1970, section 7(b) would assume great importance when three major interstate pipelines—Arkansas-Louisiana, Transco, and United—announced pro rata curtailments in violation of contractual obligations.[229] With differences in customer need, volumetrically equal reductions were otherwise unequal, and hard choices had to be made about distributing the shortfall. "Human-need" customers such as the elderly, the young, and the sick, in particular, were less able to absorb a cutback than were commercial establishments or industrial users.

Instead of pipeline versus pipeline or fuel versus fuel, the commission and courts had to contend with customer versus customer. The stakes were high. For electric utilities under curtailment, substitution to fuel oil could double customer bills. Curtailed industries turning to higher priced fuel oil could find their competitive positions threatened. In homes without adequate heat, illness or even tragedy could occur.

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[223] Hunt v. FPC, 306 F.2d 334 (5th Cir. 1962), reversed on other grounds, 376 U.S. 515 (1964).

[224] Sec. 7(c), Pub. L. 75-688, 52 Stat. 825 (1938).

[225] See City of Detroit et al., 6 FPC 196 (1947); City of Detroit et al., 7 FPC 1 (1948); Panhandle Eastern Pipe Line Company et al., 7 FPC 48 (1948); Panhandle Eastern Pipe Line Company et al., 7 FPC 984 (1948); Panhandle Eastern Pipe Line Company, 8 FPC 1339 (1949); Panhandle Eastern Pipe Line Company, 9 FPC 1330 (1950); and Panhandle Eastern Pipe Line Company et al., 10 FPC 328 (1951). The earliest occurrence of mandatory natural-gas allocation was in 1918 when the U.S. Fuel Administration used its wartime powers to allocate gas according to a five-tiered priority schedule to relieve a gas shortage in New York State. "Government Control of Gas," *OGJ,* October 25, 1918, p. 2.

[226] See H. T. Koplin, "Conservation and Regulation: The Natural Gas Allocation Policy of the Federal Power Commission," *Yale Law Journal* 64, no. 6 (May 1955): 842–43.

[227] Panhandle Eastern Pipe Line Company, 11 FPC 575 (1952).

[228] Sunray Mid-Continent Oil Co. v. FPC, 364 U.S. 137 (1960); and United Gas Pipe Line Co. v. FPC 385 U.S. 83 (1966).

[229] This section is adopted from Richard Merriman and Peyton Bowman, "The 1970s—A Period of Momentous Change," in AGA, *Regulation of the Gas Industry,* vol. 1, chap. 5; and Jerome Muys, "Federal Power Commission Allocation of Natural Gas Supply Shortages: Prorationing, Priorities, and Perplexity," *Proceedings of the Rocky Mountain Mineral Law Institute,* vol. 20 (New York: Matthew Bender, 1975), pp. 301–58.

The first commission response was to have pipelines under curtailment prepare new tariff plans. Instructions for priority classes were also provided in the 1971 order.[230] In the same year, a curtailment plan was devised for United Gas.[231] The next action was a five-class priority curtailment plan for El Paso Natural Gas in 1972.[232]

To formalize industry standards and replace voluntary arrangements, several commission orders were issued in early 1973 that set an eight-tiered hierarchical "end-use" plan, which was soon followed by a similar nine-tiered plan.[233]

Contract provisions for interruptible service and pro rata allocation were not allowed. Explained the commission:

> We are impelled to direct curtailment on the basis of end use rather than on the basis of contract simply because contracts do not necessarily serve the public interest requirement of efficient allocation. In times of shortage, performance of a firm contract to deliver gas for an inferior use, at the expense of reduced deliveries for priority uses, is not compatible with consumer protection.[234]

Strict implementation of the Order 467 series was overruled in appeals court where it was opined that specific guidelines could only be established per hearing.[235] Tailored curtailment plans followed, including those of Arkansas-Louisiana (eight tiers, 1973), United Gas (five tiers, 1973), Southern Natural (seven tiers, 1975), and Transco (nine tiers, 1976).[236]

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[230] *Order 431,* "Policy with respect to establishment of measures to be taken for the protection of as reliable and adequate service as present natural gas supplies and capacities will permit," 45 FPC 570 (1971).

[231] *United Gas Pipe Line Company,* Opinion 606, 46 FPC 786 (1971).

[232] *El Paso Natural Gas Company*, Opinion 634, 48 FPC 931 (1972).

[233] *Order 467,* "Utilization and Conservation of Natural Resources—Natural Gas Act," 49 FPC 85 (1973); *Order 467-B,* "Utilization and Conservation of Natural Resources—Natural Gas Act," 49 FPC 583 (1973); and *Order 467-C,* "Utilization and Conservation of Natural Resources—Natural Gas Act," 51 FPC 1199 (1974). Priority groups ranged from "high-priority" users captive to gas to "low-priority" industrial and electric power plants capable of substituting to oil to endure interrupted service. In order of priority, the hierarchy was (1) residential, small commercial users of under 50 Mcf per peak day; (2) large commercial users of over 50 Mcf per peak day, industrial firm requirements for plant protection, feedstock and process needs, and pipeline-customer storage-injection requirements; (3) all users not specified; (4) industrial boiler-fuel uses of 1.5 MMcf to 3 MMcf per day with alternate fuel capability; (5) industrial boiler uses of over 3 MMcf per day where substitution was available; (6) interruptible uses of between 0.3 MMcf and 1.5 MMcf per day where alternative fuels existed; (7) interruptible users of between 1.5 MMcf and 3 MMcf per day capable of substitution; (8) interruptible users of between 3 MMcf and 10 MMcf per day capable of substitution; and (9) interruptible users of over 10 MMcf per day. In addition to human need, the bias toward domestic uses over industrial uses was because of the hazards of restarting pilot lights in residences.

[234] *Arkansas Louisiana Gas Company,* Opinion 643, 49 FPC 53 at 66 (1973).

[235] Pacific Gas & Electric Co. v. FPC, 506 F.2d 33 (D.C. Cir. 1974) (holding that FPC's Order No. 467 was a general policy statement, not a binding rule; thus not subject to APA notice-and-comment and not reviewable under § 19(b) of the Natural Gas Act).

[236] *Arkansas Louisiana Gas Company,* Opinion 643, 49 FPC 53 (1973); *United Gas Pipe Line Company,* Opinion 647, 49 FPC 179 (1973); *Southern Natural Gas Company*, Opinion 747, 54 FPC 2298 (1975); and *Transcontinental Gas Pipe Line Corporation,* Opinion 778, 56 FPC 2134 (1976). Final plans became interim plans, necessitating new hearings and opinions from court reversals. For example, see State of Louisiana et al. v. Federal Power Commission, 503 F.2d 844 (5th Cir. 1974); and State of North Carolina et al. v. Federal Energy Regulatory Commission, 584 F.2d 1003 (D.C. Cir., 1978).

FPC curtailment plans, like any enforced rationing plans, encountered difficulties. One early problem was the jurisdictional status of direct industrial sales. If they were beyond commission authority, only voluntary pro rata plans were possible, leaving local distribution companies subject to FPC curtailment plans. The appeals court agreed, but the Supreme Court came to the FPC's rescue with an interpretative twist that the commission's authority over transportation, not rates, controlled the issue, hence curtailment orders applied to direct sales as well as indirect sales.[237]

A second major issue involved compensation. Certain electric utilities dependent on natural gas as a boiler fuel, primarily in the South and West, had to substitute fuel oil, which was more than three times as expensive on a heating-value basis, while high-priority gas customers enjoyed relatively inexpensive gas. Noted Richard Merriman and Peyton Bowman, "A person with a gas stove and gas heat could escape practically unscathed from a gas shortage while the next-door neighbor with electric appliances encountered a doubling of utility bills."[238]

Sentiment developed to have high-priority customers share the burden with other less fortunate customers, perhaps by a surcharge on the former. The commission refused jurisdiction in one such case but was reversed by the Fifth Circuit.[239] With jurisdiction, the commission refused to modify its end-use orders to apportion compensation.

Regional inequities were the most glaring problem of curtailment. Some pipelines, such as Transco and Texas Eastern, experienced severe supply problems in the pre-1978 period, while other interstates such as Southern Natural and Pacific Gas Transmission met full demands. This meant that interruptible customers in states such as South Carolina and North Carolina were cut off, while the same customer class in Massachusetts and New Hampshire, served by lines with high reserves, were relatively unscathed.[240]

Relative industrial development of states was directly affected; North Carolina, for example, was not considered for new plant location by thirty-four firms because of gas uncertainty.[241] "From the standpoint of economic efficiency," summarized Jeffrey Harrison and John Formby, "the administrative allocation of natural gas has been an unmitigated disaster."[242]

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[237] Federal Power Commission v. Louisiana Power & Light Co., 406 U.S. 621 (1972).

[238] Richard Merriman and Peyton Bowman, "The 1970s—A Period of Momentous Change, "in AGA, *Regulation of the Gas Industry,* vol.1, p. 5-20.

[239] Mississippi Public Service Commission v. FPC, 522 F.2d 1345 (5th Cir. 1975).

[240] Jeffrey L. Harrison and John P. Formby, "Regional Distortions in Natural Gas Allocations: A Legal and Economic Analysis," *North Carolina Law Review* 57, no. 1 (October 1978): 57, at 82–85. Severely curtailed states were North and South Carolina, Florida, Mississippi, Georgia, Alabama, Minnesota, Arizona, and Tennessee; above-average curtailed states were Arkansas, California, Nevada, Nebraska, Kansas, Louisiana, Iowa, Missouri, Virginia, Kentucky, Delaware, Ohio, and North Dakota; and moderately curtailed states were South Dakota, Maryland, West Virginia, Oregon, Wisconsin, New Mexico, Indiana, Utah, Pennsylvania, Washington, New York, and Connecticut. Little to no forced rationing was experienced in Illinois, Wyoming, Idaho, New Hampshire, Vermont, Colorado, Michigan, Texas, Oklahoma, Montana, Massachusetts, Rhode Island, and Maine.

[241] Jeffrey Harrison and John Formby, "Regional Distortions in Natural Gas Allocations," at p. 87.

[242] Jeffrey Harrison and John Formby, "Regional Distortions in Natural Gas Allocations," at p. 88.

Other mandatory-allocation problems were defining interruptible service, base-period levels, and alternate-fuel substitution. The unreliability of end-use data was the "Achilles heel of [the FPC] programs."[243] No customer class was satisfied unless it received priority. "In short," stated an FPC solicitor, "what we have is a group of petitioners none of which will concede that a program can ever be just and reasonable unless their individual gas supply is given highest priority and highest protection."[244] The customer clash was not only between direct (favored) and indirect (nonfavored) customers but between existing customers and new customers.

Not only did the FPC and the judiciary spring to action in the troubled 1970s. To supplement the NGA, the Emergency Natural Gas Act of 1977 was passed and immediately activated by President Carter.[245] FPC chairman Richard Dunham, appointed administrator of the act, promptly issued orders to reallocate gas between firms, establish emergency guidelines, and relax import and maritime regulations that hampered gas procurement.[246] With the end of the cold winter of 1976–77, curtailments eased, and the act was rescinded on April 1, 1977.

In 1946, the FPC ruled that interstate pipeline regulation extended to integral storage facilities.[247] As they did for pipeline projects, certification applications had to demonstrate funding, supply, demand, reasonable cost, and quality of service.[248] When requisite conditions were in doubt, temporary authorization was sometimes granted.[249]

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A jurisdictional question concerning interstate pipeline storage facilities was whether an intrastate firm participating in a joint storage project with an interstate automatically became a "natural-gas company" under the NGA. A 1965 opinion found such a situation to be nonjurisdictional unless an inventory credit for compensation was granted to the interstate firm, which constituted a sale for resale by the intrastate firm.[250]

At the close of 1978, 216 underground gas-storage projects were operated by interstate carriers under FERC jurisdiction. Nine types of project facilities, all of which inject gas in "shoulder" periods to meet demand in "peak" periods, primarily residential demand in the winter, require separate certification.[251]

Antitrust and general monopolization issues have a long if infrequent history in the manufactured- and natural-gas industry. In 1889, an Illinois court ruled that the Chicago Gas

[243] Jerome Muys, "Federal Power Commission Allocation of Natural Gas Supply Shortages," p. 327.

[244] George W. McHenry Jr., oral argument transcript in State of Louisiana et al. v. Federal Power Commission (5th Cir. 1974), p. 101, quoted in *Louisiana v. FPC,* 503 F.2d 844, 869 n.56 (5th Cir. 1974).

[245] Pub. L. 95-2, 91 Stat. 4 (Emergency Natural Gas Act of 1977). Proclamation 4485, 42 *Fed. Reg.* 6789 (February 2, 1977).

[246] See Richard Merriman and Payton Bowman, "The 1970s—A Period of Momentous Change," pp. 5-26 to 5-29.

[247] Interstate Nat. Gas Co., Inc. v. FPC, 331 U.S. 682 (1947).

[248] *Natural Gas Storage Company of Illinois,* Opinion 236, 11 FPC 366 (1952).

[249] John Cheatham, "Regulation in the Post–World War II Period," p. 4-32.

[250] *Natural Gas Pipeline Company of America et al,* Opinion 480, 34 FPC 1258 (1965). This qualification would be modified by the commission in a later decision.

[251] See S. K. Smith, Jr., "Pipeline Gas Supplies," in AGA, *Regulation of the Gas Industry,* vol. 1, p. 12-48.

Trust had to sell its stock interest in four other manufactured-gas companies because its monopoly position violated its corporate charter.[252] But a pure antitrust suit against a gas-transmission firm would come nearly seventy years later.

On December 23, 1957, a certificate of public convenience and necessity was awarded to El Paso Natural Gas, then the sole interstate supplier to the California market, to operate the recently acquired Pacific Northwest Pipeline Corporation, a 1,500-mile line from Seattle, Washington, to the San Juan Basin, despite an antitrust suit against the merger filed by the U.S. attorney general.

This lawsuit represented the first major antitrust action against an interstate natural-gas line. The FPC had taken jurisdiction over the public-interest implications of the merger despite the pending suit and was upheld by the lower court. The Supreme Court reversed.[253]

The suit was decided in 1964 by the Supreme Court, which ruled that an antitrust violation had taken place "unless Section 7 of the Clayton Act has no meaning in the natural gas field."[254] El Paso was ordered to divest Pacific Northwest Pipeline, and after several divestiture plans were rejected by the courts, a separation agreement was approved on August 29, 1968. Court action continued until March 1973, and full separation was finally accomplished in 1979.[255]

The reduced bound of its authority in light of the antitrust decision was recognized by the FPC in its 1966 annual report.

> The Commission's approval of an acquisition of assets does not exempt the transaction from subsequent prosecution under the antitrust laws.... The Commission cannot even make its statutory determination ... as long as an antitrust action directed against the acquisition is pending in the courts.[256]

Subsequent rulings have been consistent with this pronouncement.[257]

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The Natural Gas Pipeline Safety Act, enacted on August 12, 1968, instructed the secretary of transportation to set minimum safety regulations for pipelines—intrastate gathering and trunk lines as well as interstate lines.[258] The industry had successfully followed a voluntary code,

[252] People ex rel. Peabody v. Chicago Gas Trust Co., 130 Ill. 268 (1889). Cited in William Letwin, "Congress and the Sherman Antitrust Law: 1887–1890," *University of Chicago Law Review* 23, no. 2 (Winter 1956): 245.

[253] California v. FPC, 369 U.S. 482 (1962).

[254] United States v. El Paso Natural Gas, 376 U.S. 651 (1964).

[255] "In the past 16 years the case has come before the Supreme Court no fewer than eight times. Some 39 companies, Government agencies, and private citizens have joined the case over the years. At one point, a bill was introduced in Congress to exempt the ... merger. ... El Paso paid close to $16 million to lawyers and public relations men during its losing fight." *Time,* March 19, 1973, p. 73.

[256] Federal Power Commission, *Forty-Sixth Annual Report* (Washington, DC: Government Printing Office, 1967), p. 10.

[257] See John Cheatham, "Regulation in the Post–World War II Period," pp. 4-29 to 4-30.

[258] Pub. L. 90-481, 82 Stat. 720 (1968).

the American Standard Code for Pressure Piping, Gas Transmission, and Distribution Piping Systems, first established in 1942 by the American Society of Mechanical Engineers, yet many states chose to make the code mandatory. By 1968, all states except Nebraska and South Dakota had done so.[259]

The FPC sought minimum federal safety standards beginning in 1950. In the next decade, the drive intensified to "sustai[n] and improv[e] ... the voluntary code's present standards and mak[e] them mandatory in all States where pipelines operate."[260] The industry by this time was ready for a federal standard in place of forty-eight state standards, and this uniform standard was incorporated into certification requests.

Prior to 1968, safety-related issues were discussed in commission hearings, and only accident reports were mandatory. Despite constant amendments, numbering thirty-two in the federal law's first decade, prescribed "performance standards" were not a major impediment to pipeline construction and operation.[261] The law, in any case, was not born of necessity. It was testament to the urge to regulate, given the satisfactory safety record of the industry prior to the law.[262]

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The National Environmental Policy Act of 1969 required environmental impact statements for all major federal actions directly affecting the environment.[263] The new requirements were incorporated into the certification process whenever a major environmental impact was judged present. This added to the heavy paperwork load of pipeline firms entering or exiting the market and expanding or curtailing service.

Pipeline right-of-way through public land and Indian land is closely supervised by federal authorities with environmental conditions in mind. Permits must be secured from the Interior Department with review and approval by different agencies and subagencies.

Projects in national forests are reviewed by the Forest Service (U.S. Department of Agriculture); projects in Indian territory must be approved by the Bureau of Indian Affairs (Interior Department); projects in a wildlife refuge are evaluated by the Fish and Wildlife Service (Interior Department); projects in recreational or historic areas must secure approval from the Heritage Conservation and Recreation Service (Interior Department); and projects

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[259] Martin Armstrong, "The Natural Gas Pipeline Safety Act of 1968," *Natural Resources Lawyer* 2, no. 2 (May 1969): 144.

[260] Federal Power Commission, *Forty-Sixth Annual Report,* p. 136. Cited in John Cheatham, "Regulation in the Post–World War II Period," p. 4-40.

[261] Mel S. Martin, "Natural Gas Pipelines—Their Regulation and Their Current Problems," *Proceedings of the Thirtieth Annual Institute on Oil and Gas Law and Taxation* (New York: Matthew Bender, 1979), pp. 255–56.

[262] A study in 1966 revealed that only sixty-four fatalities occurred with some 800,000 miles of continuously run pipelines between 1950 and 1965. Federal Power Commission, *Forty-Sixth Annual Report,* pp. 133–35. To Martin Armstrong, legislation in the face of the industry's safety record made pipelines "a scapegoat for the politically-motivated 'consumerism' which became a preoccupation of the [Johnson] administration." Armstrong, "The Natural Gas Pipeline Safety Act of 1968," p. 153.

[263] Pub. L. 91-190, 83 Stat.852, at 853 (1970).

near or in water areas must be approved by the Army Corps of Engineers. In most cases, the Bureau of Land Management (Interior Department) has primary responsibility.

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Unique in the annals of NGA regulation is the Alaska Natural Gas Transportation System, which was ten years in the making.[264] The 1968 discovery of the Prudhoe Bay field in northeastern Alaska was a major gas discovery in addition to the oil find, accounting for more than 10 percent of U.S. proven gas reserves.

The first proposal to pipe gas to the contiguous United States was presented to the FERC in March 1974 by a consortium of American and Canadian pipeline firms (Arctic Gas Proposal). Another proposal by the El Paso Alaska Company followed in September 1974. Slowing the certification process were both sponsors' requests for an "all-events full cost of service tariff," which would have had consumers pay for all project costs regardless of gas delivery. Federal loan guarantees were also in the air.

A third proposal by the Alcan Pipeline Company in July 1976 did not formally propose an all-events tariff and government subsidies but offered little concrete evidence that investors would bear the risk instead of consumers and taxpayers. With the three mutually exclusive proposals, 250 days of hearings followed with more than 250 volumes of testimony and exhibits. Other hearings were held before Congress and Canadian officials. Before the hearings ended on November 12, 1976, the Alaska Natural Gas Transportation Act was passed.

In light of the severe gas shortage in the lower forty-eight states, the act imposed a May 1, 1977, deadline on the FERC to recommend one of the three proposed carrier systems to the president.[265] This gave Congress and the president jurisdiction to grant entry, prescribe regulations, and set tariffs. With the FERC deadlocked over the Arctic and Alcan proposals, the choice was given to Canadian authorities, who chose the Alcan plan on July 4, 1977.

President Carter concurred, and in November 1977, Congress passed a joint resolution approving the choice.[266] Pursuant to the Natural Gas Policy Act, the field price was fixed at $1.45 per million British thermal units, adjusted for inflation from base-period April 1977, with no producer allowance for conditioning the gas, a matter that was disputed along with other financial issues.

Also in dispute was the ownership of the pipeline itself. In July 1977, the Department of Justice intervened to recommend that producers be banned from participating in the pipeline's financing because undersizing and nonaccess to outsiders would result. The position was accepted by the president and Congress; producers were banned from owning equity in the project, participating in management, or guaranteeing debt in the initial

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[264] This discussion is taken S. K. Smith, Jr., "Pipeline Gas Supplies," pp. 12-74 to 12-83.

[265] Pub. L. 94-586, 90 Stat. 2903 (1976).

[266] Other joint resolutions in 1980 and 1981 encouraged the project. See Tussing and Barlow, *The Natural Gas Industry,* p. 83.

financing.

Facing the fact that more delay was probable without the most logical financiers, the Department of Justice, under new leadership, consented to producer and pipeline sponsorship of the Alaska portion of the line in June 1980. Work began to join the Canadian and contiguous U.S. portions already under construction. But with the 4,800-mile project less than one-third complete, construction stalled amid financing woes.

The new reality of falling gas prices made guaranteed cost recoupment in rates obsolete, and federal subsidy was out of the question. Regarding the former, natural-gas prices to industrial users were constrained by substitute-fuel prices, and any attempted cost passthrough would price the gas out of the market. The fate of the uncompleted portions of the pipeline and huge North Slope gas reserves was in question.

Summarized Arlon Tussing in 1983:

> The upheaval that has occurred in natural-gas markets since 1980 means, effectively, that an Alaska gas-transportation project is either an idea whose time has yet to come or, more likely, one whose time has come and gone.... It is indeed conceivable that Prudhoe Bay gas will *never* be a marketable commodity. Before it can become such a commodity, the worldwide energy situation, the technological menu, or both, will have to change in ways that we cannot now foresee.[267]

NGA Regulation in Retrospect

For more than four decades, interstate gas pipelines have been subject to public-utility regulation, ostensibly to check natural-monopoly characteristics to keep prices and quantities competitive at the city gate. The theoretical basis and practical results of the regulatory effort, however, are open to complete review. Natural-gas pipelines are not ipso facto natural monopolies, and even if they were, voluntary contracts and market processes can prevent "monopolistic" outcomes.

Correcting a "lack" of competition with state franchises and the Natural Gas Act, moreover, is a "cure" far worse than the "disease." These government interventions are classically monopolistic, awarding government grants to exclusively or semi-exclusively serve markets.

While restricting entry and rivalry, authorities have attempted to mimic the competitive environment by limiting rates to cost plus a prescribed rate of return on valued capital. The surrogate approach to market competition not only fails to recognize market decision-making as a *discovery process* that is inherently competitive, it institutionalizes inefficient practices to maximize returns under regulatory constraints.

Short of an empirical estimate of a negative price savings for customer classes under the NGA, a review of the general record confirms the distortions and waste of public-utility

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[267] Arlon Tussing and Connie Barlow, An Epitaph for the Alaska Gas Pipeline? *(Or Will Alaska Gas Ever Get to Market?)*. Natural Gas Insights, vol. 1 (Seattle: ARTA Inc., Summer 1983), pp. 9, 20.

regulation.[268] What an unhampered market would have produced cannot be known—only surmised. What lines would have been built if customer contracts rather than certification had decided the issue? How much sooner would these lines have been built, and how many more "waiting-list" customers would have been served?

What would the cost and rate structure have been for different markets? And finally, how much sooner would the revolutionary changes of the 1980s have been implemented without the public-utility status of the industry?

A political fact can be noted at the outset to suggest that not all is well with the standard interpretation of the need for interstate natural-gas-pipeline regulation. The passage of the NGA and its subsequent operation have been generally supported by both consumer interests and the regulated pipeline industry. If it is assumed that consumers desire lower prices and pipelines desire higher prices and profits, then one group misspecified its mean-ends framework by forsaking the free market for government intervention. Given consumer unrest compared to that of the pipeline industry during the regulatory tenure, the political mistake seems to lie with the former.

Early Consequences

In congressional hearings in 1941, several Congressmen asked industry witnesses why interstate pipeline activity had slowed in the first three years of the Natural Gas Act. William Dougherty, representing four interstates, noted that a "lag in the construction of new facilities in the new areas" was because the FPC had not decided "the rate of return and other types of regulatory procedure." He added, "The first rate proceeding that was initiated was initiated in July 1938 and is not yet completed."[269]

The status of wellhead sales in interstate commerce was another major area of regulatory uncertainty. The first shot under the NGA concerned affiliate gas-acquisition costs between an interstate and its production subsidiary where interstate carriage was performed. Between 1940 and mid-1945, over $100 million in annual rate reductions was ordered.[270] Faced with calculating the allowable price on discovery cost instead of market value, many pipelines were forced to practically give their gas away.[271] The logical response was to not develop gas reserves and, where possible, to sell reserves to independents to receive full market value. In 1945, interstate carriers provided 35 percent of their own throughput; seven years later this

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[268] An empirical study by Stephen Breyer and Paul MacAvoy on natural-gas-pipeline rate regulation in the early 1970s reached the "inescapable conclusion" that "the value of Federal Power Commission price-setting activities has been either very low or zero." Breyer and MacAvoy, *Energy Regulation by the Federal Power Commission* (Washington, DC: Brookings Institution, 1974), p. 54.

[269] *Natural Gas Act Amendments, Hearings,* p. 34. Part of the slowdown was due to coal- or fuel-hauling railroads' refusing to grant right-of-way to pipelines entering new markets. See *Natural Gas Act Amendments, Hearings,* pp. 52–58.

[270] Marjorie Clark, "Protection of the Consumer under the Natural Gas Act—Refunds and Reparations," *George Washington Law Review* 14, no. 1 (December 1945): 271.

[271] See the concurring opinion of Justice Jackson, Colorado Interstate Gas Co. et al. v. Federal Power Commission, 324 U.S. 581, 611 (1945) (Jackson, J., concurring).; and *Business Week,* September 6, 1952, p. 156.

dropped to 15 percent with the remainder purchased at arm's length.[272] This not only transferred market share to producers but discouraged a fertile source of reserve additions.

Later in the 1940s, a justifiable fear developed that FPC regulation would extend to independent producers by virtue of their sales contracts with interstate carriers. This encouraged intrastate sales in lieu of interstate agreements, withholding of supply from the market, and "escape-clause" contracts to void agreements should jurisdiction be claimed by the FPC.[273] Production incentive was dampened for independents as it already had been for pipeline affiliates. Flaring and other gas-conservation problems were encouraged. The regional advantage of gas-producing areas over gas-importing regions, now dependent on higher priced coal and fuel oil, was artificially enhanced.[274]

The low-price policies of the FPC, valuing reserves at depreciated cost, had adverse consequences for consumers and would-be consumers of gas. In the winter of 1946–47, a gas shortage occurred as demand outraced the capacity of Panhandle Eastern's pipeline to serve Detroit and other Michigan markets.[275] Although commonly interpreted as a war-related problem of rationed steel's preventing an expansion of the line, the problem was regulatory. Gas prices were prevented from rising to ration demand to available supply.

In other words, depreciated-cost valuation failed to reproduce a market-clearing price that local distributors could pass along with their markup to consumers during peak demand periods. Material-acquisition problems may have limited pipeline capacity more than otherwise would have been the case, but price inflexibility made capacity short of demand.

The less obvious result of regulation in the 1940s and early 1950s was service delays to waiting-list areas. Although demand was present, long-term supply contracts, necessary to get pipelines from the drawing board to reality, discouraged by regulation or the threat thereof, were not. While serviced consumers gained by lower prices, would-be consumers were left with higher fuel-oil and coal bills—and when later connected, higher contract prices.[276] And

[272] Robert E. Hardwicke, "Some Consequences of Fears by Independent Producers of Gas of Federal Regulation," *Law and Contemporary Problems* 19, no. 3 (1954): 342, at 354–55.

[273] Robert E. Hardwicke, "Some Consequences of Fears by Independent Producers," p. 355. See chapter 8, pp. 371, 385, 390–91.

[274] Robert E. Hardwicke, "Some Consequences of Fears by Independent Producers of Gas of Federal Regulation," pp. 356–59. The conservation distortion was a hotly debated point in Congress. See Kenneth Marcus, *The National Government and the Natural Gas Industry,* pp. 303, 305, 518.

[275] "Panhandle Easter Gas Supply Allocated in FPC Order," *OGJ,* December 21, 1946, p. 39; and Carl Wheat, "Administration by the Federal Power Commission of the Certificate Provisions of the Natural Gas Act." This was the third major instance of a natural gas shortage in the United States. In the winters of 1916–17 and 1917–18, West Virginia suffered industrial and civic shutdowns as a result of below-market pricing by the state's public-utility commission.

[276] Distributor regulation at the state level also played a major part in delaying the expansion of gas service to eager markets. H. J. O'Leary cites one vivid example: "The introduction of natural gas in Wisconsin was delayed from 1941 to 1949. The Wisconsin legislature, which yielded to the opposition of coal, railroad and labor interests, contributed to the delay by passing repressive legislation and excessive taxes applicable to natural gas service.... In the interval between 1941 and 1950 the buyer's market for natural gas was replaced by a seller's market.... The delay in securing gas cost Wisconsin distributors at least 30 to 50 percent more for gas at the city gate." "Distribution and Utilization of Natural Gas," *American Economic Review* 43, no. 2 (May 1953): 546.

to the extent that future supply was discouraged by artificially low interstate gas prices as a result of regulatory uncertainty, even short-run beneficiaries would pay for their bargain prices in higher renewal rates.

The growth of natural-gas pipelines in the late 1940s and early 1950s was both because of and in spite of regulation. A *Business Week* article in 1950 reported that between 1945 and 1950, ten major firms had raised $1.5 billion from "a relatively predictable future"—stable gas-acquisition costs, FPC-sanctioned 6 percent returns, certification barriers to new entrants, and strong demand.[277] Public-utility protection reinforced fundamental economics in this heyday.

But less than two years later, the same magazine reported that the industry's phenomenal growth was threatened by regulation. Gas-acquisition prices had doubled as a result of declining affiliate production, reluctance of independents to sell new discoveries interstate, and FPC inaction on proposed rate hikes that tracked higher gas-acquisition costs.[278] The result was below-market pricing at the city gate, which led to the reappearance of spot shortages in the 1951–53 period.

Although tremendous expansion was taking place, regulatory lag and other distortions from FPC intervention gathered strength as a counteracting force. Growth would continue but at a markedly slower rate than in the 1946–51 golden years when regulation helped more than hurt pipelines.[279]

In 1954, the discriminatory treatment of pipeline production was ended, and the independents' fear of contracting interstate was vindicated by comprehensive regulation of natural-gas field prices pursuant to the *Phillips* decision.[280] Numerous escape clauses were activated, and notices of withdrawn gas dedications were given by interstate pipelines to their customers. Quick FPC action, however, later upheld by the courts, voided such clauses.[281]

Despite regulatory "certainty," problems had just begun. With interstate gas regulated and intrastate gas unregulated, interstate pipelines found twenty-year supply dedications scarce. It would be more than two years after *Phillips* before a major interstate project was announced, and the 574-mile pipeline from the Texas Gulf Coast to Miami, Florida, was finalized only because of nonregulated gas sales from producers to industrials. (This unregulated area became regulated in 1962.) The pipeline received a straight carriage fee for its services.[282]

At about the same time, a second chilling blow to pipeline expansion occurred. In late 1957, a U.S. court of appeals ruled that cost passthroughs by transmission companies did not have to

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[277] *Business Week,* November 25, 1950, pp. 96–98.

[278] *Business Week,* September 6, 1952, pp. 152–57.

[279] Between 1946 and 1950, $1.4 billion was raised for pipeline expansion. Despite inflation, only $2 billion in financing was raised between 1951 and 1961. Richard Rosan, "Post–World War II Growth of Gas Industry," in AGA, *Regulation of the Gas Industry,* vol. 1, p. 3-14.

[280] See chapter 8, pp. 376–79.

[281] See this chapter, p. 885. Nonetheless, escape clauses were allowed where official certification had not been awarded, which doomed several planned projects.

[282] *Time,* January 14, 1957, p. 88.

be automatically allowed by the FPC, a ruling that shelved four major projects. The Supreme Court reversed in the *Memphis* decision, ending a one-year pipeline-construction moratorium.[283]

The record of major interstate-pipeline construction from the post-World War II boom until the slowdown in the late 1950s is shown in table 15.2.

Table 15.2

INTERSTATE PIPELINE CONSTRUCTION: 1939–59

Date of Completion	Company	From–To	Miles	Diameter (inches)
1944	Tennessee	Tex. Gulf–Cornwall, W.Va.	1,265	24
1947	El Paso	West Tex.–So. Calif.	1,200	26–30
1949	Mich.-Wisc.	North Tex.–Detroit	1,609	24
1950	Transco	Tex. Gulf–NYC	1,840	26–30
1951	El Paso–Pacific	N.M.–San Fran.	–	24–34
1951	Tennessee	Penn.–Mass.	520	–
1951	Natural	Tex. Gulf–Chicago	1,300	26–30
1951	Trunkline	La. Gulf–Ill.	1,300	24–26
1953	Tex. Eastern	N.J.-Boston	–	–
1954	Gulf	La. Gulf–W.Va.	1,150	30
1956	Mich.-Wisc.	La.–Mich.	1,200	30
1956	Pacific-N.W.	Calif.–Wash.	1,487	22–26
1959[a]	Houston Corp.	Tex. Gulf–Florida	1,931	24
1959	Tennessee	Tenn.–Chicago	350	30

SOURCE: Arlon Tussing and Connie Barlow, *The Natural Gas Industry*, pp. 35–36.
NOTE: No pipelines were constructed between 1939 and 1944. In 1945, the "Big Inch" and "Little Inch" pipelines were converted from petroleum to natural gas.
[a]In 1957 and 1958, three foreign pipelines with U.S. destinations were built.

Twilight and Crisis: 1960–80

The slowdown of the 1950s became a quagmire in the 1960s. The mature industry—consumers in all lower forty-eight states had gas service by 1966—was a major factor but not the only one.[284] Interstate price regulation began to transfer natural-gas growth to home-state markets to escape FPC jurisdiction. Interstate dedications became scarce as price controls became more stringent, beginning with President Kennedy's FPC appointments in the early 1960s. The 1960 *Sunray* decision, which dedicated gas reserves for life, was another reason for gas to stay in home states.

Activist regulation at the wellhead and transmission level resulted in only four major interstate projects in the 1960s compared to over a dozen the decade before. They are listed in table 15.3.

283 *Business Week,* December 13, 1958, p. 29.

284 Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* p. 55.

Table 15.3
INTERSTATE PIPELINE CONSTRUCTION: 1960–70

Year of Completion	Company	From–To	Miles	Diameter (inches)
1960	Tennessee	Minn.–Wisc.	504	24
1960	Transwestern	Tex.–Calif.	1,300	24–30
1961	Pacific Gas	Canada–Calif.	1,400	36
1967	Great Lakes	Minn.–Mich.	989	36

SOURCE: Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* p. 37.
NOTE: NO new pipelines were built in 1968–70.

Certification denials joined wellhead policies to hinder the growth of interstate transmission. Attempts by pipelines to bypass regulation by entering into contracts to directly supply industrials and electric-utility customers, including "most of the new interstate pipeline proposals submitted in the early 1960s," were throttled.[285] Prominent casualties in the decade included projects to link Hugoton field gas to St. Louis industrials, Wyoming reserves to southern California, and a Tennessee Gas proposal to ship gas from Texas fields to Los Angeles utilities.

The 1970s would be an infamous decade for the natural-gas industry. In the 1970–71 winter season, curtailments by major pipelines began that continued the next year and returned in the 1974–75 and 1975–76 heating seasons. New pipeline construction was beyond contemplation; the question was, who would be curtailed and by how much. The scramble to find interstate dedications led to administrative actions to encourage producers and culminated in the Natural Gas Policy Act of 1978.[286]

At the end of the decade, pipeline executives worked feverishly to contract for reserves to meet what seemed to be insatiable demand at any price. Supply proved adequate at the regulated price for the next several heating seasons, and by 1981, a new reality dawned—surplus or gas "bubble." The challenges to and responses of interstate pipelines—and the demoted role of regulation—are examined in Appendix 15.1.

Public-Utility Regulation Reconsidered

The Case for Regulation. Compared to interstate oil pipelines, which were subject to a weak form of public-utility regulation, interstate gas lines were under traditional public-utility control with original-cost ratemaking and entry and service subject to close administrative scrutiny. Such heavy-handed regulation was the result of a perception that pipelines are natural monopolies and create market failures. Economist James McKie made this argument:

> Competition will not work in the pipeline transmission of natural gas. The average throughput costs of pipelines tend to decrease with size to such an extent that there is seldom economic room for more than one pipeline to serve

[285] Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* p. 56. The Tennessee denial is discussed below.

[286] See chapter 8, pp. 423–30.

> any point of consumption. Even the very largest consuming markets can be served by only two or three, and each of these two or three may pass through areas en route where it is the only supplier.... [Pipelines] cannot engage in price competition in the sale of gas. Direct costs are very low in relation to overhead costs. Price competition would amount to chronic price warfare.
>
> Furthermore, now that the pioneering stage of the industry is over, pipelines cannot determine that allocation of markets and routes among themselves by private decision and competitive bidding. Orderly development of the industry requires that the public authority do these things by franchise. In short, pipelines are public utilities.[287]

McKie's argument can be distilled into four components:

1. Gas pipelines are natural monopolies with a firm's range of decreasing cost covering the entire range of consumption;
2. Even where more than one firm serves a market, monopoly prevails from locational control (singular hookups);
3. High fixed costs and low variable costs make price wars—hence instability—"chronic"; and
4. Market-share decisions by pipeline firms cannot be rationally determined in the industry's mature stage.

Natural-gas users with alternate-fuel capability in a free market would face monopoly prices set at levels competitive with those of the inferior substitutes coal and fuel oil. Captive users would pay more—literally what the utility desired. Worse still, as occurred prior to regulation in the last century, gas users would be inconvenienced by inadequate service caused by disruptive rivalry. Enlightened regulation would correct these shortcomings. The competitive regulated price would replace the free-market monopolistic price by the ratebase method, and service regulation would ensure nondiscriminatory service for the entire market and a minimum level of service from a strong, franchised industry.

The Case for Regulation Reconsidered. The case against regulation—which has scarcely attracted the same attention as the case for regulation—is developed at length in this section. The major arguments center on competition in the gas-pipeline industry, the protection of captive gas users at the distribution-company level, the problems of public-utility ratemaking, and the political problems of the regulatory solution.

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A peculiarity of the public-utility argument is that free-market competition is criticized as too little (the "natural monopoly" argument) and too much (the "cutthroat competition" argument). A more balanced view is that free-market competition is neither insufficient nor overstimulated but continually *resource-adjusting* toward a consumer-dictated level of service. Competitive conditions are continually defined, which outside of this entrepreneurial discovery process cannot be known or implemented.

[287] James W. McKie, *The Regulation of Natural Gas* (Washington, DC: American Enterprise Association, 1957), p. 15.

When entry is needed (i.e., when profitable opportunities exist), entry takes place—despite the wishes of the entrenched supplier, which explains the origin of state franchise and federal certification law. When multiple entrants are suffering losses, consolidation efficiently redeploys resources. These are socially positive responses to unstable, unsustainable situations and are "equilibrating" toward efficient resource allocation.

The competitive process with high-fixed-cost assets such as gas pipelines is not perpetual chaos. Instability is not desired for its own sake. Potential competition "regulates" the existing firm or firms to discourage overpricing that leads to new entry. Long periods of stability as the result of competitive pricing can be imagined. Government intervention in the last century *prevented* the process from reaching this point—at the request of entrenched firms—but the free market cannot be blamed for leaving the job half done or undone.

Competition is omnipresent for interstate gas carriers in an unregulated market. There is potential competition, competition from substitutes, and, in many cases, pipeline-on-pipeline rivalry.

Potential competition is the possibility that a new pipeline will enter an occupied market to capture a growth load or attempt to replace the existing firm on the strength of executed contracts. The physical construction of a new pipeline or a purchase of existing facilities represents a new firm's displacing the traditional supplier or suppliers. It is to the consumers' advantage to allow timely entry and pipeline-on-pipeline competition that regulation can only discourage.

Certification notwithstanding, the historical firm's market share is not set in concrete. Strong competitive pressure exists for firms in place to watch costs and profit so that the outside market does not view their pricing as uncompetitive and inviting of entry.[288] In short, potential entry makes firms compete as if a competitor already existed.

A traditional argument for price regulation is that a particular pipeline market is not "workably competitive." Thus, unregulated pricing would be above marginal cost and monopolistic. A major flaw of this argument is that the disincentive of regulated pricing will keep the market from being "workably competitive," whereas pure profits would incite new entry to make the market "workably competitive" or at least more so.

Second, extraordinary profits are necessary for some markets to be served at all. It is much better that consumers—even captive users—have the choice of natural gas at unregulated prices than be left with phantom gas service at a "competitive" rate. One firm created by market conditions is wholly preferable to no firm created by regulatory conditions.

Substitute competition is a second competitive force bearing on interstate gas pipelines. Economist Charles Phillips noticed several decades ago that "the gas industry is subject to

[288] This is not to say that natural-gas pipeline markets are "perfectly contestable" where "entry is absolutely free and exit is absolutely costless." William J. Baumol, "Contestable Markets: An Uprising in the Theory of Industry Structure," *American Economic Review* 72, no. 1 (March 1982): 2. A useful criticism of this theory, centered on such unrealistic assumptions, is provided in William G. Shepherd, " 'Contestability' vs. Competition," *American Economic Review* 74, no. 4 (September 1984): 575–79.

strong actual and potential competition from electricity, coal steam, and fuel oil."[289] This statement can be amended by adding nuclear power, hydroelectricity, and purchased power as rivals to gas in electric-power generation. In fact, natural gas has gone from a day-in, day-out *base-load* source in electric generation to a *swing* source in most markets, satisfying the last increment of demand.

Since gas power plants and industrial boilers typically burn oil also, prices of residual fuel oil represent the upper boundary for gas prices, net of conversion costs. These alternatives, including conservation, make gas demand price sensitive. How much total revenue changes from price increases is an empirical question that varies from market to market and time to time, but recent experience indicates that gas prices are price-elastic as a result of strong interfuel competition and conservation.[290]

Pipeline-on-pipeline competition in major markets further questions the natural monopoly description of interstate pipelines. As with oil pipelines, scale economies do not necessarily imply natural monopoly. Entrepreneurial error, a finite range of scale economies, and demand growth often make one pipeline inadequate to serve a particular market.[291] It is naive to think of a pipeline as "one size fits all" to preclude the need for entry.

McKie, writing in 1957, characterized interfirm rivalry as the exception rather than the rule. By the 1960s, one informed observer noticed "a marked increase in competition among pipelines," whereby "most major market areas today [1970] have two or even three sources of gas supply."[292]

Examples include the New York-New Jersey area, which has been supplied by Texas Eastern (1945), Transco (1950), and Tennessee Gas (1955); Chicago, which is served by Peoples (1931) and Midwestern (1959); Detroit, which is served by Panhandle Eastern (1936), Michigan-Wisconsin (1949), and Great Lakes (1957); Washington, D.C., which is serviced by Atlantic Seaboard (1931) and Transco (1967); southern California, which is served by El Paso (1947) and Transwestern (1960); northern California, which is served by El Paso (1947) and Pacific Gas Transmission (1961); and Upper Michigan, which is served by Michigan Consolidated (1933) and Michigan-Wisconsin (1949).

Numerous interstate pipelines offer strong potential entry by building parallel lines ("looping") should a neighboring market be inadequately served by its existing "monopolist."

States with multiple interstate pipelines are Texas (13), Louisiana (10), Oklahoma (8), Kansas (8), Illinois (8), Ohio (8), Arkansas (7), Kentucky (7), Mississippi (7), Missouri (7), New York (7), Colorado (6), Pennsylvania (6), Tennessee (5), New Jersey (5), Indiana (5), Alabama (5), New Mexico (4), Nebraska (4), Wyoming (4), Iowa (3), Maryland (3),

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[289] Charles Phillips, *The Economics of Regulation* (Homewood, IL: Richard D. Irwin, 1965), p. 362. Also see George J. Stigler and Claire Friedland, "What Can Regulators Regulate? The Case of Electricity," *Journal of Law and Economics* 5 (October 1962): 11.

[290] See appendix 15.1, pp. 949–57, on the increased competition in interstate gas markets.

[291] This point applies equally to any "undersizing" argument applied to gas pipelines. For a critique of the undersizing argument with oil pipelines, see chapter 14, pp. 842–43.

[292] Carl Bagge, "The Federal Power Commission," pp. 690, 701.

Michigan (3), Virginia (3), West Virginia (3), Connecticut (2), Georgia (2), Massachusetts (2), Minnesota (2), Montana (2), South Carolina (2), Rhode Island (2), and Wisconsin (2).[293] Intrastate pipelines in gas-producing states offer more competition.

Multifirm competition aside, monopoly is claimed to be the rule rather than the exception because individual areas within broader markets have only one supplier. This is a tenuous theory of monopoly. All providers of goods and services have a geographical monopoly to one extent or another, which reduces to the truism, as noted by economist Murray Rothbard, that "only one thing can be in one place at one time."[294] Locational advantage, like price and service quality, is an integral aspect of real-world rivalry; only in the hypothetical world of perfect competition do consumers have infinite locational-nonspecific choices before them.

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Defranchising gas distributors and decertifying pipelines would open the field to reveal true competitive conditions, but most certainly it would remain uneconomical for different suppliers to offer service to each consumer. As in many areas of the Midwest, one pipeline and one distributor may be the sole alternative to other fuels, but this "monopolistic" situation, unchecked by regulation, does not make consumers worse off because of the high-cost implications of the "competitive" solution. Dual pipelines in such situations would require prohibitive demand charges—certainly anti-consumer—and are noneconomic from the word go.

Efficiency, in short, requires singular service. But far from justifying regulated pricing, such situations invite self-help solutions to integrate the consumers' bargain into the pricing equation as seen below.

While residential and commercial users of gas for space heating, water heating, cooking, and clothes drying do not have dual-fuel capability that sets an upper limit on price, this does not mean that they are at the whim of their local distribution company. Self-help and market processes can effectively substitute for public-utility ratemaking, not because the free-market alternative is perfect but because the regulatory solution, as argued later in this section, is relatively imperfect.

New residences and business establishments have energy alternates at the outset, although they become captive once the initial decision is made. New users choose between gas and electricity, and, in some cases, oil and coal. These choices in a nonregulatory environment invite long-term contracts to lock in acceptable rates and service terms. Failure to do so is not

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293 States with one interstate transmission company are California, Arizona, Idaho, Florida, New Hampshire, North Carolina, North Dakota, Oregon, South Dakota, and Washington; states without interstate natural-gas service are Alaska, Delaware, Hawaii, Maine, Nevada, and Vermont. *Implementation of Title I of The Natural Gas Policy Act of 1978, Hearings Before the Senate Committee on Energy and Natural Resources, November 5 and 6, 1981,* 97th Cong., 1st sess. (Washington, DC: Government Printing Office, 1982), pp. 1107–11.

294 Murray Rothbard, *Man, Economy, and State* (Los Angeles, CA: Noah Publishing, 1970), p. 615. For a critique of locational monopoly price, see pp. 615–19.

so much a market failure as buyer imprudence.

For existing captive users, contracting is also viable. Under regulation, the distributor has been able to offer its cost-plus rate as a "take it or leave it" proposition to customers in its franchise area. The only recourse for residential and other customer classes is political lobbying before state public-utility commissions.

This would change in a free-market setting. On the one hand, the utility could offer an unregulated "take it or leave it" rate. If this default rate were unacceptable, an entrepreneurial opportunity would be created for consumers to organize to collectively bargain with the distribution company. In the jargon of economists, "monopoly" would be countervailed by "monopsony." An advantage of this approach for both parties is that regulatory costs are eliminated—leaving private contracting costs that presumably would be much less.

A contractual impasse could lead to new ownership of the gas firm or even customer ownership (the free-market equivalent of municipal ownership). Consumers could also fan public opinion to achieve a competitive solution. But there would be no public-utility commission or legislature to which to resort.

With newfound market discipline of gas distribution, hitherto absent, cost minimization would be exerted upstream to pipelines, intrastate and interstate, and producers.[295] The Natural Gas Act would no longer be needed, even from its proponents' perspective.

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Captive users have an *elasticity of demand* that sets an upper bound on prices. Budget-constrained consumers *conserve,* which is one way of saying that there is a tradeoff between price and quantity demanded. The profit-maximizing utility will rescind any price increase that reduces total revenue because of lost sales. Citing the nearly 20 percent drop in residential gas sales in the last decade as a result of increasing gas rates and other factors, Arlon Tussing and Connie Barlow concluded:

> The *price-elasticity of demand* is a far more formidable hazard because it begins to cut deeply into sales volume at gas prices well below those of competing fuels.... Residential customers turn down thermostats, stop heating unused rooms, and cover windows with plastic. And a gas-price rise which is expected to be permanent (even if gas prices are still well below those of alternative fuels), will prompt consumers to substitute capital for energy.[296]

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"In a broad sense," Eli Clemens states, "the objective of public utility rate regulation is to achieve through regulation the same result that would be achieved through competition."[297]

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[295] Deregulation could lead to the integration—or reintegration—of the three industry phases for major companies, much as is the case in the oil industry.

[296] Arlon Tussing and Connie Barlow, "The Price Elasticity of Residential Gas Demand," Natural Gas Insights, (Seattle, WA: ARTA Inc. December 1983), pp. 4–5.

[297] Eli Winston Clemens, *Economics and Public Utilities* (New York: Appleton-Century-Crofts, 1950), p. 153.

The “just and reasonable” price is derived by passing through prudent costs and limiting profit to depreciated cost multiplied by a “normal” return. The key is to limit profit; costs directly associated with providing the service are more-or-less given.

This seemingly straightforward methodology of rate determination proves problematic upon deeper reflection. First, there is no objective “just or reasonable” price or even a “zone of reasonableness.” What is just and reasonable to one person or for one project may not be to another person or project. Consumers want low prices and suppliers desire high prices. Some consumers prefer higher prices and secure supply to lower prices and less certain supply. (Curtailments, even to high-priority users, made this choice very real in the 1970s.) High-risk projects require the potential for quick payouts, necessitating prices well above cost. A single “public-interest” price, even different prices tailored for each customer class, does not exist because preference and risk are heterogeneous.

“Just and reasonable” is not a “competitive” or “just” price. Competitive prices cannot be synthetically produced under regulated conditions as they can be in theory under simplifying assumptions (marginal-cost pricing). Only the market can reveal competitive conditions.[298]

A false presumption of public-utility regulation is that costs can be minimized, capital value can be measured, the right return can be calculated, and the “scientific findings” can be implemented in the political arena without suboptimal modification. These shortcomings are analyzed below.

Cost-of-Service Passthrough. Profits are not added to a “given” cost in market situations; they come out of cost as entrepreneurs reduce expenses without impairing revenue. Under public-utility regulation, the situation is quite different. Costs are passed through, with minor exceptions, and a profit allowable is added. So long as a pipeline’s rates can be increased without a loss of total revenue, a range of costs can be loosely managed without financial detriment to the firm.

Wages, salaries, benefits, and rental and maintenance expenses are prime candidates; they are rarely scrutinized by authorities.[299] Other cost items must be arbitrarily dealt with by authorities who are placed in the position of substituting their judgment for the economic calculations of management—something the courts have limited the regulators’ jurisdiction to do. What types of advertising, charity, and research expenses should be allowed, and how much? Particularly difficult is deciding what research and development expenses to allow—expenditures that may or may not benefit consumers in the future but must be paid by present

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[298] Two major suggestions for regulatory pricing in place of “imperfect” market pricing, setting prices at marginal cost and according to the elasticity of demand, are defective substitutes. Marginal-cost pricing falsely assumes that cost is objective and discernable for implementation. It also begs the question of cost minimization. Marginal costs, not only average costs, can be artificially inflated without market incentives to maximize profits. Elasticity pricing (Ramsey pricing), on the other hand, assumes perfect knowledge for perfect market segmentation and lacks incentive for cost minimization. Only the lure of pure profit can ensure that a minimum amount of resources is expended to maximize production elsewhere.

[299] This is not to say that flagrant padding always occurs, but without full market discipline, there is less pressure to separate lean from fat if *known* or even to *recognize the difference* in many instances.

ratepayers.

The regulatory alternative is not a free good. Taxpayers fund commission activities and ratepayers fund reporting, compliance, and legal expenses associated with regulation. Lawyers particularly benefit. The multitude of legal issues surrounding certification, rate-case, and other filings creates a voluminous demand for their services, the fees for which are passed through to consumers.

Problem of Regulatory Return Determination. Profit is derived from multiplying the depreciated cost of a firm's assets by a rate of return. The determination of the rate base, the maximum return rate, and the composite profit pool is arbitrary in method and distortive in practice.

Regarding the determination of the *rate base,* historical cost gives an imperfect estimate of the worth of a firm. Only in equilibrium are the two equal; outside of equilibrium, error and changed circumstances can make cost much lower or higher than value. Original cost is particularly prone to error during inflationary times when market value can race ahead of dollar cost. Value is not cost, historical or reproduction, but the subjective estimations of buyers and sellers as best reflected in the stock market.

In addition to incorrectly valuing the firm, the cost-plus ratemaking method does not incite cost minimization but the opposite. The incentive is to enlarge the rate base to increase the profit pool or at least counteract the "vanishing ratebase" phenomenon created by depreciation.[300] There are many subtle ways a firm can do this—from buying an extra airplane to erecting a prestigious skyscraper for the home office. Whether or not such "discretionary" expenditures are needed cannot be proven or disproven *a priori*; it is something only economic calculation under free-market conditions can reveal.

Artificially maintaining and even "padding" the rate base is an institution in the interstate natural-gas industry (as elsewhere under public-utility regulation). Those practices are much less common for intrastate gas pipelines in such states as Texas where public-utility regulation has been light-handed or absent.

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An example of artificially maintaining the rate base occurred in 1980 when Algeria ceased shipping liquefied natural gas (LNG) to a consortium of interstate purchasers. Rather than run the remaining LNG inventory through the re-gasification facility and close the plant after several days to minimize operating costs, El Paso, Columbia, and other partners ran LNG at minimum rates for eight months to maintain the project's ratebase valuation.

The disastrous supplemental gas projects of the 1970s resulted not only from overly optimistic expectations during the energy boom but from *the fallback of ratebase treatment.* The rate base served as a safety net to allow marginal projects to contribute to a firm's

[300] This is particularly true when original-cost valuation during inflationary times shrinks the rate base to levels below the firm's achievable profit level.

income as much as stellar assets. LNG projects were at the forefront. A proposed LNG plant in California was shelved in 1982 with the majority of $400 million in pre-construction expenses put in the rate base for recovery (with a return) from utility customers.[301]

This paled in comparison to an El Paso LNG project with Algeria's Sonatrach. With the help of a $400-million tanker loan guarantee under the Merchant Marine Act and a minimum bill tariff (minimum purchase requirement) to pass through costs, the re-gasification terminal began deliveries in 1978. With world prices escalating, the sovereign Sonatrach demanded and received a new contract in May 1978.

A second re-negotiation in December of the same year was nixed by the Department of Energy, and in April 1980, deliveries were terminated. The plant and tankers, lacking alternative uses, were almost complete losses, which forced El Paso to write off $365 million in associated investments. The federal government (taxpayers) had to retire its $400-million obligation. Private losses have gone into the rate bases for recovery, although court disputes, not to mention effective rate ceilings imposed by substitute-fuel competition, make full recovery in interstate gas rates unlikely.[302]

A third LNG venture of Panhandle Eastern, representing over $600 million in plant and tanker investments, weathered a re-negotiation storm with Sonatrach, although the high price of liquefied gas boded ill for the project.[303]

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A coal-to-gas project turned into an even bigger boondoggle than the aforementioned LNG projects. In the 1970s, many pipelines dedicated research and development funds to high-B thermal unit coal-gasification projects with ratebase passthrough. Several major projects were abandoned prior to construction—a $1.3-billion project of Texas Eastern and Pacific Lighting and a $3.5-billion project of Panhandle Eastern. But one $2-billion project, the Great Plains Coal Gasification Project, bullish on energy prices and flush with government subsidies, went ahead in 1981. The economics of the project fell apart with the reversal of natural-gas prices in 1982, and numerous subsidies and concessions were made by authorities before the project was abandoned.[304]

The lesson of supplemental gas failures is illustrative of the shortcomings of public-utility regulation, which discourages entrepreneurial innovation and cost minimization, while promoting risky capital projects that can be "bailed out" by ratebase treatment once certified. The bottom line is that a firm's cost is higher under public-utility regulation than under free-market conditions where the lower the cost, the higher the profit.

In fact, the difference between regulated gas-acquisition costs and market-clearing gas prices has represented "a huge pork-barrel out of which the pipelines and distribution companies

[301] Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* p. 66.

[302] Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* pp. 65–69. Also see chapter 16 p. 1007.

[303] Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* pp. 70–71.

[304] See chapter 10, pp. 580–83.

could finance steady expansion and upgrading of their regular facilities (even in the face of stagnant sales), as well as new investments in schemes to supply gas from unconventional sources (imported LNG, synthetic fuels, and gas from the Arctic) at costs many times the price of conventional suppliers."[305]

These examples are consistent with the Averch-Johnson thesis: "If the rate of return allowed by the regulatory agency is greater than the cost of capital but is less than the rate of return that would be enjoyed by the firm were it free to maximize profit without regulatory constraint, then the firm will substitute capital for the other factors of production and operate at an output where cost is not minimized."[306]

Original-cost valuation impedes asset transfers between pipeline firms because the assets remain at original cost in the rate base.[307] Prospective owners are limited to returns based on original depreciated cost and face the specter of the vanishing rate base. This discourages asset reallocations to entrepreneurs better able to employ them.

Yardstick *rate-of-return* assignments treat entrepreneurship as a nonspecific talent. In the free market, entrepreneurs of varying ability perceive different opportunities and implement alternatives to perform regular tasks. Different profit-loss margins result and change with new developments. Public-utility standardization of profit treats every pipeline project as if it were equally desired by the market and equally managed by entrepreneurs. True profit-loss signals that alert the market that changes are needed are falsified.

Many pipeline companies integrated into oil and gas production in the 1950s to receive unregulated returns.[308] In the next decades, these firms increasingly turned to non-energy ventures with mixed results. In any case, public-utility regulation influenced firms to leave their primary areas and venture into fields in which their expertise was less.

A basic argument against standardized returns is the absence of an average or normal rate of return. Each project is unique. Profits from other industries or even fellow pipeline projects used to derive a common return reflect influences that are foreign to the project in question. Entrepreneurial talent and business situations are not accurately "priced" under public-utility regulation, which scrambles the signals that are used for economic calculation.[309]

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[305] Arlon Tussing, "Permanent Devolution: The Agonies of Half-Hearted Decontrol in the Natural-Gas Industry," American Enterprise Institute, Washington, DC, 1984, p. 3.

[306] Harvey Averch and Leland L. Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review* (December 1962): 1053. Paul Joskow has questioned the Averch-Johnson thesis by claiming that to authorities, price changes are as important as, or more important than, rates of return. Consequently, firms will minimize costs to increase returns at a given price and will minimize costs to avoid a rate hearing to increase prices. Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Price Regulation," *Journal of Law and Economics* (October 1974): 291–327. This point has some validity, but it is relatively minor compared to the virtually automatic rate increases approved by the FPC and FERC over nearly fifty years.

[307] Walter Gallagher, "Rate of Return," pp. 30-92 to 30-94.

[308] *Business Week,* November 5, 1955, p. 120.

[309] One return methodology, the cost-of-money approach, has been blatantly criticized as "remov[ing] all incentive for obtaining cheap money and for efficient operation." Charles I. Francis, "Rate Regulation of Natural Gas Companies by the Federal Power Commission," *Law and Contemporary Problems* 19, no. 3

Profit limitations on interstate gas carriers have a subtle consequence that dilutes the regulatory aim of limiting profit to limit price. Without large profits, and having a need to pay out a major portion of allowed margins as dividends to stockholders, pipelines have depended heavily on debt finance instead of retained earnings to finance expansion. This has increased those firms' obligations, which have increased risk compared to less leveraged firms. This has forced the commission to allow higher profits—and higher rates for consumers—to compensate investors.[310]

Problems of Implementation: Bureaucratic Management, Politics, and Inefficiency. Pipeline regulation from beginning to end is political. It is born of a political mandate, is overseen by politically appointed commissioners of widely varying qualifications,[311] and is judicially reviewed by more political appointees. Politics, not the maximization conditions of neoclassical economics, controls the issue.

This obvious fact would not need to be presented if many economists favoring regulation were not silent on the issue. Not only do they believe competitive conditions can be discovered by nonmarket means, an economic fallacy, it is assumed that they can be implemented without political modification. The experience with pipeline certification, as with other regulated goods and services, confirms this view as naive.

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Inefficiency has been the hallmark of FPC activity with natural-gas pipelines. In the early 1950s, regulatory lag interfered with rate increases required to neutralize higher costs. This reduced profit margins and threatened continued expansion. The industry also complained about vague standards for rate determination and other important matters. Pleaded one lawyer in 1954:

> The least to which the natural gas industry is entitled after spending thousands of dollars, and days, weeks, and even months in the preparation of testimony ... is that the Commission indicate where and to what extent it agrees or disagrees with that presentation.... The fact appears to be that the Commission either has been unwilling to clarify its position, or unable to do so because it has arrived at no final determination.[312]

The *Public Utilities Fortnightly* in the same year similarly observed:

> The [FPC] Staff also seems to have shown some propensity for "changing the rules" as each new case came up.... The Staff's thinking ... appears not to have

(Summer 1954): 432. Also see Charles I. Francis, "Federal Regulation of Interstate Shipment and Sale of Gas," *Proceedings of the Fourth Annual Institute on Oil and Gas Law and Taxation* (New York: Matthew Bender. 1953), pp. 121–22.

310 Walter Gallagher, "Rate of Return," pp. 30-54 to 30-58.

311 Truman crony Monrad Wallgren was a jeweler, optometrist, congressman, senator, and governor of Washington before becoming an FPC member from 1949 to 1951. "Maybe He Improved," *OGJ,* October 27, 1949, p. 49. A chart of commissioners and their previous occupations is contained in M. Elizabeth Sanders, *The Regulation of Natural Gas,* pp. 74–75.

312 Charles I. Francis, "Rate Regulation of Natural Gas Companies by the Federal Power Commission," p. 431.

> "jelled" completely, with resulting variations which involve extra time and effort in the preparation of cases and considerable guesswork as to the final results of the orders.[313]

The situation worsened with wellhead regulation beginning in 1954 and has remained a problem to the present. Commenting on the 1950–69 period, one attorney remarked:

> The single most pervasive problem of FPC regulation since 1950 has been delay in the resolution of pending proceedings.... While the FPC has attempted from time to time to reform its procedures so as to expedite the regulatory process... delay and resulting uncertainty was characteristic.[314]

Not only the attorneys involved have noticed a lack of clarity about permitted industry practices and inconsistent reasoning in FPC decisions. In a spot check involving approximately 350 cases, totaling over a thousand pages, economist Paul MacAvoy complained that he was unable either to find substantive content or to decipher trends in the commission's 1969 caseload.[315]

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Red tape has become a way of life for the regulated industry. Certification delays associated with the Alaska gas pipeline during the worst natural-gas shortage in history are eloquent testimony to the shortcomings of political decision-making.

In an overview of pipeline ratemaking procedures, Francis Quinn and Cheryl Foley advised companies to expect as much as several years between the time a rate proposal is submitted to the FERC and the time it becomes effective. This period involves not only commission inactivity but court review as well.[316]

The obvious consequence is the inability of firms and consumers to make informed decisions. Quick exploitation of recognized opportunities by entrepreneurs is prevented, while the hearings process bares all competitive secrets of a firm. Proposed rates can take effect after a suspension, but refunds can be ordered if a final decision does not allow any or all of the increase. In the meantime, economic calculation by the market participants is compromised. Do consumers conserve or substitute? Should the pipeline expand its facilities or earmark disputed revenue for other uses? The price system under the cloud of rate suspensions or refunds is not its reliable self.

Government certification of new projects and service modifications radically restricts the

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313 "The FPC Backlog of Gas Rate Cases," *Public Utilities Fortnightly,* January 21, 1954, pp. 108–9.

314 Richard Rosan, "Post–World War II Growth of Gas Industry," p. 3-38.

315 "This review can only apply the burden of proof on the authors of the volume to show that there is some content in these cases—that a decision was made on an issue based on consistent reasoning, and that the decision had some economic effect on those involved or, later, on those carrying on the same activities." Paul W. MacAvoy, "The Formal Work-Product of the Federal Power Commissioners," *Bell Journal of Economics and Management Science* 2, no. 1 (Spring 1971): 394.

316 Francis Quinn and Cheryl Foley, "Procedures in Pipeline Ratemaking," in AGA, *Regulation of the Gas Industry,* p. 36-6. Former FERC general counsel Charles Moore estimated that at any one time 16,000 or more dockets concerning production and transmission matters are before the FERC. *Houston Post,* September 14, 1983, p. 80.

ability of entrepreneurs to effectively marshall resources in accordance with consumer preference. In its 1940 annual report, the FPC referred to the certification process as a "serious effort to control the unplanned construction of natural-gas pipe lines with a view to conserving one of the country's valuable but exhaustible energy resources."[317] This view reflects the erroneous belief that bureaucrats in the political arena have better knowledge of the present and future state of consumer demand than do entrepreneurs working through capital markets.

But whose money is on the line, and does not profit-loss reward business acumen and correct bad business judgment? That normally reliable entrepreneurs and investors, who supply thousands of goods and services in the economy, lose their bearings with pipe and vapor fuel is counterintuitive. The intrastate market, where pipelines have been much less regulated, can hardly be described as unplanned or chaotic. It has thrived and has avoided the ratebase boondoggles and shortages that have plagued the interstate market.

Insights about the efficiency of economic calculation in a free market apply to all economic objects, gas pipelines included. The hazards of government-as-entrepreneur, in contrast, are evident with pipelines as with other goods and services. The *Transwestern* case, in which a pipeline expansion was refused certification because forthcoming nuclear power was predicted to preempt its need, is a reminder of imperfect governmental decision-making.[318] Voluntary transactions between buyer and seller are prima facie proof of economic viability, short of ratebase malincentives.

§§

Certification has meant many things to many people. To established interstate pipelines it was potentially a ticket to stability; to regulators it represented a significant expansion of authority; to rival fuels it was a new lease on life to avoid—or at least delay—displacement; and to consumer advocates it was the "price" of public-utility regulation that promised lower prices. The result of certification was to politicize entrepreneurial decision-making and slow the competitive process.

As early as 1942, potential entrants in the interstate gas pipeline business were warned by attorney Carl Wheat:

> Careful preparation [of certification filings] seems ... to be both desirable and essential, especially since objecting intervenors from the coal, railroad and labor interests have frequently appeared and participated in such proceedings.... Their presence and active participation in such proceedings have frequently served to prolong hearings to lengths unheard of in most certificate proceedings before other regulatory bodies.[319]

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[317] Federal Power Commission, *Twentieth Annual Report* (Washington, DC: Government Printing Office, 1940), p. 78. Also see James McKie's argument in this chapter, pp. 921–92.

[318] See this chapter, p. 898.

[319] Carl Wheat, "Administration of the Federal Power Commission of the Certificate Provisions of the Natural Gas Act," pp. 201–2.

Coal-related and fuel-oil interests testified before the commission against certification applications until the 1960s when their influence waned. But "end-use" victories were won, and delays in many cases made the effort worthwhile. The entire "aggrieved parties" effort was anti-consumer and a major cost of government regulation of entry.

Although regulation is potentially an instrument of monopoly—gas pipelines able to obtain certification to exclusively serve defined market areas—interfirm rivalry generally was allowed, reflecting the commission's preference for rivalry. But some applications were denied, and the burden of proof was always on the potential entrant, not on the historic firm.

In all certification tussles, gas service to new consumers was delayed, leaving them with more expensive energy substitutes. Two particular cases may be mentioned. Detroit, which regularly suffered winter gas shortages from an inability of Panhandle Eastern to handle peak demand, had to wait five years before the FPC (and the SEC regarding financing) awarded certification to the Michigan-Wisconsin Pipe Line Company.[320]

In 1950, the "Battle of New England" between subsidiaries of Tennessee Gas Transmission (TGT) and Texas Eastern Transmission (TET) and their respective chairmen, Gardiner Symonds and Reginald Hargrove, renewed a feud that had begun when TET narrowly outbid TGT for the lucrative Big Inch and Little Inch pipelines after World War II. TGT first applied to the FPC for certification to supply the entire New England market, followed by TET. After several years of dispute, the FPC split the market between them. But the feud was not over. A vindictive Symonds obstructed completion of TET's line on legal technicalities to even the score.[321] A three-year delay caused by nonmarket elements was endured by consumers.

Other examples of the anti-consumer certification hearings could be chronicled. At one point the Justice Department entered the FPC's domain to file an antitrust suit against three companies who worked to keep a fourth company out of their territory through certification proceedings.[322] Although for naught, the action underscored the controversy involved in interstate-pipeline regulation designed to "protect" consumers.

Certification is a political contest between the "haves" and "have nots." Established fuel interests and established gas pipelines were given a forum in which to protect market share against new entrants. Consumers, especially those awaiting service, were victims of the "haves" along with potential entrants. In a free market, there has always been a role for new firms trying to compete their way into prominence. The certification process mitigated this process by substituting bureaucratic conservatism and politics for unfettered rivalry.

One noteworthy example of bureaucratic rigidity over competitive market flexibility may be mentioned. The FPC adopted a benchmark of twenty-year gas supply contracts to approve projects, while investors were inclined to finance projects with shorter throughput

[320] *Newsweek,* January 12, 1948, p. 63.

[321] Admitted Symonds: "They delayed us for two years ... and made all the trouble they could. I'm just vindictive enough to want to do the same thing to them." *Time,* December 8, 1952, p. 96.

[322] *Business Week,* May 10, 1958, p. 29.

agreements.[323] To the detriment of waiting consumers, this precluded a number of pipeline projects that would have arisen on the free market. It is true that risk is higher with shorter supply contracts, but consumers could well prefer to save money in the interim and recontract for supply later.

A new supply contract might be signed or another reserve-rich project might step into the breach if profitable. Long-term supply contracts with nonperformance penalties could easily cover the costs of reconversion in a worst-case situation. At least consumers could decide for themselves the merit of a pipeline, as did pipeline operators and investors; certification simply reduced the range of alternatives for all involved. Intrastate pipelines and their consumers have benefited without a supply-year minimum; only rarely has a carrier failed to honor supply commitments to distribution companies.[324]

Although clothed in public-interest garb, government regulation of entry, exit, and terms of service has been anti-competitive and anti-consumer. It has also been *anti-environmental*—natural-gas expansions have been delayed or blocked in favor of fuel oil and coal. These conclusions are not changed by the observation that certification has not been as restrictively employed as it could have been—and has been in other transportation fields under federal regulation, as seen in the next chapter.

Conclusion. Public-utility regulation constructs nonmarket retail and wholesale prices. If the resulting retail or wholesale prices are too low, the gas industry is weakened. Less pipeline expansion can be undertaken, exploration and production are discouraged, well abandonments increase, gas is wastefully used, and the specter of shortages is introduced.[325] If retail and wholesale rates are too high, consumer wealth is unnecessarily reduced, and the industry is artificially stimulated. In both cases, price misinformation misaligns demand with the relative scarcity of gas versus alternative fuels.

What assurance is there that political processes can discover and implement the "right" price, and more fundamentally, how can "competitive conditions" be known outside of the rivalry of the market? Theory and experience suggest that under regulation, forces are at work to distort cost and price away from competitive levels. Political pressure exists to reduce prices as low as possible for residential users and other favored classes at the expense of suppliers and lower priority users, while barriers to competition and efficiency increase firm costs over unregulated levels.

[323] Paul W. MacAvoy, "The Effectiveness of the Federal Power Commission," *Bell Journal of Economics and Management Science* 1, no. 2 (Autumn 1970): 284.

[324] In Texas, for example, where reserve years are not a precondition for permits, only one pipeline in one period (Lo Vaca in 1973–75) encountered supply problems and broke contracts. Victimized customers successfully pursued legal remedies. Other prominent intrastates have delivered as agreed over many decades—Lone Star, Delhi, Enserch, El Paso, Tenneco, and Houston. It is self-interest that provides an adequate reserve base and a free-market environment that offers the reasonable opportunity to perform contractually.

[325] Natural gas shortages in the 1970s resulted not only from wellhead price controls but also from an inability of transmission companies to price incremental supplies at market-clearing rates at wholesale. For criticism of regulatory rate design at the pipeline and distributor level, see Richard J. Pierce Jr., "Natural Gas Rate Design—A Neglected Issue," *Vanderbilt Law Review* 31, no. 5 (October 1978): 1089–1164.

Public-utility regulation must be recognized not as the solution to a “defective” alternative but as a defective alternative in itself. The experience of interstate-gas-pipeline regulation in its four-decade history does not contradict this thesis.

Other Federal Regulation and Proposals

Other federal legislation in addition to the Natural Gas Act of 1938 has affected natural gas transmission. Most of these laws, like the NGA itself, were born of crisis. In the 1930s, it was the breakdown of state regulation; in the 1970s, gas shortages and the general energy crisis.

In the late 1970s, new federal authority joined the NGA. The Alaska Natural Gas Transportation Act of 1976 required owners and nonowners of this line to have equal access to transportation.[326] The nondiscrimination requirement for nonowners stopped short of common carriage.

The Emergency Natural Gas Act of 1977, as mentioned, gave emergency authority to the president to require transportation arrangements between interstate and intrastate carriers and construct required facilities.[327] These powers were readopted a year later in the Natural Gas Policy Act.[328] A second supplement to NGA regulation was the Outer Continental Shelf Lands Act Amendments of 1978 that made offshore gas pipelines common carriers.[329] Purchases and carriage were to be nondiscriminatory, even to the point of requiring expansion of throughput capacity. Commenting on the pervasiveness of these laws in addition to the NGA, Mel Martin commented:

> Interstate natural gas pipeline companies can now be required, by federal regulation, to perform the functions of contract carriers, common carriers, and common purchasers. What else may be required?[330]

A companion bill to the NGPA was the Powerplant and Industrial Fuel Use Act, which sought to conserve natural gas and fuel oil, two highly regulated fuels experiencing supply problems, by limiting their use in existing and new power plants and major fuel-burning installations.[331] Existing plants were restricted to their current usage of natural gas until 1990 when an oil and gas ban was to take effect.

New plants could not use oil or gas, which in effect restricted them to coal burning—despite cost and environmental considerations. With improving supply conditions, the Industrial Fuel Use Act was amended in 1981 to allow existing plants to increase natural-gas consumption. The 1990 ban was also removed.[332] The surviving prohibition on new plants’ burning oil and gas gave an artificial advantage to existing plants and coal, but the surplus of the two

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[326] Pub. L. 94-586, 90 Stat. 2903 (1976).

[327] Pub. L. 95-2, 91 Stat. 4 (1977).

[328] Pub. L. 95-621, 92 Stat. 3350 (1978).

[329] Pub. L. 95-372, 92 Stat. 629 at 638–39 (1978). Previously, the Outer Continental Shelf Act of 1953 required purchase and transportation by pipelines without discrimination. Pub. L. 83-212, 67 Stat. 462 (1953).

[330] Mel S. Martin, “Natural Gas Pipelines—Their Regulation and Their Current Problems,” p. 235.

[331] Pub. L. 95-620, 92 Stat. 3289 (1978).

[332] Omnibus Budget Reconciliation Act, Pub. L. 97-35, 95 Stat. 357 at 614 (1981).

restricted fuels promised further reform of the controversial 1978 law.

Pipeline safety was the focus of several laws beginning with the Hazardous Liquid Pipeline Safety Act of 1979.[333] The next year, the Comprehensive Environmental Response, Compensation, and Liability Act was passed to set a liability ceiling of $50 million "or such lesser amount as the President shall establish by regulation," but no less than $5 million.[334] Coupled with eminent-domain rights, two important costs for interstate transmission companies—right-of-way and insurance—were reduced by government favor.

Nonfederal Intervention through 1984

While their efforts have been overshadowed by the NGA, states have actively regulated and taxed intrastate gas lines. In addition, a relatively new government entity, Indian tribal governments, have expanded their taxing powers to pipelines crossing their domain.

State Level

Regulation. All fifty states have public-utility commissions that have authority over domestic, commercial, and industrial sales of natural gas.[335] Since the beginning of the industry, residential and commercial sales have come under local and state regulation; in 1947, regulation of direct sales from interstate pipelines to industrial customers was also found by the Supreme Court to be a state and local function.[336] In addition, almost one-third of the 1,600 gas-distribution companies in the United States are government owned and operated.[337]

Intrastate gas pipelines, by virtue of their sales to franchised distributors, are under public-utility control in thirty-five states; entry, terms of service, and safety minimums are regulated.[338] All states but Nebraska indirectly regulate carriers by virtue of regulating rates of gas distributors. As did federal regulation, state commissions changed from fair-value to original-cost valuation in the 1940s for gas distributors and intrastate carriers.[339] The rate of return applied to the valuation figure approximated federal allowances—6 to 7 percent—until an inflation premium was added in the late 1970s.[340]

Cost-of-service determinations for pipelines have prominently included gas purchases. By 1975, forty-three states had automatic fuel adjustment charges to pass through to consumers price increases experienced by gas carriers.[341] Rate-increase requests on the state level have

[333] Pub. L. 96-129, 93 Stat. 989 (1979).

[334] Pub. L. 96-510, 94 Stat. 2767 at 2782 (1980).

[335] Only Nebraska does not regulate rates and service standards. AGA, *Regulation of the Gas Industry,* vol. 3, Inf-10 to Inf-15.

[336] Panhandle Eastern Pipe Line Co. v. Public Service Commission of Indiana, 332 U.S 507 (1947).

[337] Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* p. 24.

[338] Arlon Tussing and Connie Barlow, *The Natural Gas Industry,* p. 24.

[339] N. Knowles Davis, "General Principles Applicable to Utility Rates," in AGA, *Regulation of the Gas Industry,* vol. 2, p. 25-6.

[340] William Diener, "State Regulation," in AGA, *Regulation of the Gas Industry,* vol. 1, p. 4-68.

[341] "Fuel Adjustment Clauses in Trouble," *Public Utilities Fortnightly,* December 18, 1975, p. 6.

been generally automatic, as in Texas.[342] Michigan, on the other hand, eliminated purchased-gas adjustment clauses in 1982.[343]

Land-use and zoning restrictions by state and local governments have shaped pipeline choices. Delay, restrictions, and paperwork costs, summarized Mel Martin, have made it difficult to "connect new wells [to pipelines] in a timely fashion."[344]

Surplus gas and rising burner-tip prices encouraged interest in *bypass* gas transactions, whereby end-users (primarily industrial customers) acquire their own gas and turn to their traditional supplier for transport services only.[345] Kentucky (1964, 1984), West Virginia (1983), New York (1984), and New Mexico (1984) required intrastate pipelines to accept tendered gas for shipment.

Voluntary common carriage as a business strategy has been practiced in such states as Iowa, Indiana, Ohio, Illinois, and Maryland. Other states debating common-carrier requirements were California, Kentucky, and Kansas.[346] Further interest in natural-gas carriage on the part of both the private sector and regulators was encouraged by surplus gas.

Taxation. States have taxed intrastate natural-gas pipelines since the beginning of the century. Texas in 1905 and Oklahoma in 1907 enacted levies of 2 percent of gross revenue to underwrite their increasing oil and gas regulatory activities.[347] Today, most states tax gas pipelines within their boundaries. State taxation of interstate flows was ruled unconstitutional by the Supreme Court in two early cases and again in 1981.[348]

Louisiana passed the First Use Tax Act of 1978 to tax all gas flows through the state that originated offshore or from another country. That act was challenged by eight eastern and mid-western states, and the Supreme Court on May 26, 1981, voided the $0.07 per thousand cubic feet (Mcf) levy as unconstitutionally burdening interstate commerce and conflicting with federal authority.[349] On June 15, the Court ordered a $600-million refund of collected taxes to rectify Louisiana's initiative at the expense of downstream consumers.[350]

Indian Tribes

By their sovereignty and power to tax, Indian nations can be considered a branch of

342 Mel Martin, "Natural Gas Pipelines—Their Regulation and Their Current Problems," p. 247.

343 *Houston Post,* May 2, 1983, p. 8A.

344 Mel Martin, "Natural Gas Pipelines—Their Regulation and Their Current Problems," p. 246.

345 Spot-gas transportation and bypass with interstate pipelines is the subject of appendix 15.1.

346 See, generally, Connie Barlow, "Carriage of Customer-Owned Gas," *ARTA Energy Insights,* September 1984.

347 Harold Williamson et al., *The Age of Energy, 1899 to 1959,* vol. 2 of *The American Petroleum Industry* (Evanston, IL: Northwestern University Press, 1963), pp. 50–51.

348 United Fuel Gas Co. v. Hallanan, 257 U.S. 277 (1921); and *State Tax Commission* v. *Interstate Natural Gas Co.,* 284 U.S. 41 (1931).

349 Maryland v. Louisiana, 451 U.S. 725 (1981).

350 40 U.S.L.W. 4709 (1981).

government along with federal, state, and local jurisdictions.[351] Their taxation power has been opportunistically used against pipeline firms. In one case, a twenty-year right-of-way renewal was unilaterally made subject to a "license and use agreement" by the involved tribe. Only when a $400,000 license was purchased could the twenty-year rental fee, negotiated at $6,000, be consummated with the Interior Department.

In another case, as discussed in chapter 7, the Navajo Tribe enacted a 5 percent business activity tax on pipeline throughput across their reservation effective July 1, 1978.[352] Pipeline throughput qualified as a "Navajo service," subjecting both El Paso and Transwestern to millions of dollars in taxes and interest. Other instances exist in which "tribes have used their right of consent as a lever on industry."[353]

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[351] See chapter 7, pp. 362–65.

[352] See chapter 7, pp. 363–64.

[353] Mel Martin, "Natural Gas Pipelines—Their Regulation and Their Current Problems," p. 244.

Appendix 15.1: Market Ordering and Spot-Gas Transportation: 1975–84

This appendix examines the dawn of a new era in the natural-gas industry that is changing time-honored relationships and practices from the wellhead to the burner tip. Traditionally, pipelines have been *merchants,* buying gas at one point, selling it at another, and performing all the aggregating functions. Pipelines with storage capabilities also performed a load-balancing function between low-sendout and high-sendout periods. Such services as transportation, gathering, and storage were “bundled” with sales rather than offered a la carte to parties who were not allowed to independently contract for gas.

Long-term contracts between producers and pipelines were the backbone of this industry structure. Rates were set at *cost of service* pursuant to regulatory instruction rather than *value of service* as in a free market.

The Natural Gas Act (NGA) and administrative regulation by the Federal Power Commission (FPC) both precluded spot-gas and contract-carriage transportation before the mid-1970s. The NGA precluded a spot market for gas by requiring long-term (ten- to twenty-year) producer contracts, perpetual dedication of supply, and formal certification hearings if a producer wished to change pipeline purchasers. The FPC explicitly blocked several attempts by the industry to substitute transportation for sales. Several industry initiatives designed to escape burdensome regulation were turned back by the FPC on narrow grounds, such as the gas was for an “inferior” end-use or the transaction price was above regulated levels.[1]

On the other hand, several certificated interstate pipeline projects escaped burdensome wellhead regulation by having end-users contract directly with producers and pay a straight transportation fee. A pipeline from Louisiana to West Virginia certified in 1954 by Gulf Interstate and a line from Texas to Florida certified in 1959 by the Houston Corporation were rare exceptions to standard commission policy.[2] But overall, the FPC was not ready to sanction “regulatory gaps” in its active agenda of economic control. Bundled sales were virtually instructed by law.

This regulatory and industry structure changed in the mid-1980s wherein many interstate pipelines unbundled transportation from sales and moved spot gas sold by producers, brokers, and affiliates to industrial, commercial, and local distribution company (LDC) customers. Transportation rates joined contract sales rates in pipeline tariff books, and many pipelines have transported growing volumes of nontraditional gas.

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[1] Federal Power Commission v. Transcontinental Gas Pipe Line Corp., 365 U.S. 1 (1961); and Arizona Public Service Co. v. FPC, 483 F.2d 1275 (D.C. Cir. 1973).

[2] See Connie Barlow, “Carriage of Customer-Owned Gas,” *ARTA Energy Insights,* September 1984, pp. 2–3. Also see chapter 15, p. 918.

The natural-gas spot market did not begin with the natural-gas surplus of the 1980s. It began during curtailments when traditional certification was relaxed to allow gas to flow from surplus areas to shortage areas. After the emergency transportation orders of the 1970s that created the opening that the surplus environment would exploit are identified, the market disorder of the new decade and the industry and regulatory responses to it are described.

Emergency Transportation: 1975–81

The forerunners to the spot-gas and carriage boom of the 1980s were the emergency transportation orders issued by the FPC (and after 1976 the Federal Energy Regulatory Commission, or FERC). The objective was to alleviate shortages by redirecting gas from amply supplied areas to threatened markets. As a result, a modest "spot" market for gas developed, although it was clearly tangential to pipeline sales from traditional system supply.

Special transportation began with Order 533 in August 1975, which allowed producers to sell gas directly from state waters to "high priority" industrial and commercial customers in curtailment and arrange for pipeline carriage.[3] Process and feedstock gas, crucial to plant operations, was at the heart of the program. In the FPC's curtailment hierarchy, these gas uses were Priorities 2 and 3. Lower priority industrial and power-plant customers (Priorities 4 and 5, respectively), as well as residential customers (Priority 1), were excluded from the self-help program.[4]

The "experimental" two-year program was intended to attract intrastate gas to interstate markets to keep plants open and workers from being laid off. The two incentives of the program were unregulated wellhead prices and legalized transportation. The commission recognized the half-regulated world that the order inaugurated.

> High priority customers might be able to buy gas directly from producers. Because such direct sales would not be subject to our rate jurisdiction, high priority customers could compete with the producer's intrastate customers for gas supplies not otherwise available to the interstate market. While the sale would be non-jurisdictional, the transportation of the gas from the producer to the buyer in interstate commerce would be subject to our jurisdiction. Such transportation would require a certificate of public convenience under Section 7(c) of the Act.[5]

By March 1977, nearly 8 billion cubic feet (Bcf) had been moved under the program, an amount that would have been greater except for the warm winter of 1975–76.[6] The FERC

[3] *Order 533*, "Policy with Respect to Certification of Pipeline Transportation Agreements," 54 FPC 821 (1975); and Order 533-A, "Policy with Respect to Certification of Pipeline Transportation Agreements," 54 FPC 2058 (1975), affirmed, American Public Gas Association et al. v. FERC, 587 F.2d 1089 (D.C. Cir. 1978).

[4] For a discussion of gas shortages and consequent priority schedules, see chapter 15, pp. 904–8.

[5] *Order 533,* Policy with Respect to Certification of Pipeline Transportation Agreements, 54 FPC 821, at 823 (1975). Sales from producers to end-users were deemed nonjurisdictional (unregulated) because a *sale for resale* was not made pursuant to section 1(b) of the Natural Gas Act. But interstate *transportation* to effectuate the deal required certification—hence transportation orders finding that the public convenience and necessity were met.

[6] For discussion of the transportation program, see "Amendments to Policy Regarding Certification of Pipeline

extended the program another two years, while warning that it would not "elevate an essentially stop-gap measure to the level of a permanent palliative to the natural gas shortage for the relatively small group of industrial concerns."[7]

While Order 533 opened the door for targeted transportation, section 311 of the Natural Gas Policy Act of 1978 (NGPA) provided a much more generic vehicle for spot-gas transportation. Like the wellhead provisions of the NGPA, the transportation section was intended to ease curtailments by facilitating interstate movements of gas. The pertinent section read:

> The Commission may, by rule or order, authorize any interstate pipeline to transport natural gas on behalf of i) any intrastate pipeline; and ii) any local distribution company [and] authorize any intrastate pipeline to transport natural gas on behalf of i) any interstate pipeline; and ii) any local distribution company served by any interstate pipeline.[8]

The "on behalf of" clause was very important. It had to be shown that the intrastate pipeline, interstate pipeline, or LDC received a clear economic benefit from the maximum five-year carriage contract.

Order 46, issued on August 30, 1979, implemented sections 311 and 312 of the NGPA.[9] Qualifying transportation contracts under two years in duration could be commenced without prior approval—only a filing within forty-eight hours of actual service was required. These "self-implementing" contracts could be extended later. Contracts longer than two years had to receive a traditional section 7(c) certificate, which meant added expense and delay.

Order 63 the next year brought Hinshaw pipelines—intrastate pipelines exempt from federal regulation despite receiving gas from regulated interstate lines—within sections 311 and 312 of the NGPA.[10] Hinshaws now had the same rights as intrastate pipelines and local distribution companies (which with their pipeline facilities were already Hinshaws in most cases). This order had the same motivation as the previous ones. "The final rule is intended to further implement the Commission's policy of integrating the interstate and intrastate natural gas markets," stated FERC, "removing administrative burdens from the sale of natural gas, and improving consumer access to natural gas."[11]

Section 608 of the Public Utility Regulatory Policies Act, along with section 311 of the

Transportation Agreements," 43 *Fed. Reg.* 5362 (February 8, 1978). The FPC blessed the services of "intermediaries," or brokers, who "charge a fee for the various types of services performed, such as planning, purchasing, contracting for gathering systems, negotiating transportation agreements, and fulfilling administrative requirements" (p. 5368).

[7] "Amendments to Policy Regarding Certification of Pipeline Transportation Agreements," 43 *Fed. Reg.* p. 5365. The commission decided not to extend the program to other existing customer classes or new customers.

[8] Pub. L. 95-621, 92 Stat. 3351 at 3388–89 (1978). Section 312 gave the commission the power to "order" or "authorize" assignments of surplus gas from intrastate pipelines to interstates. 92 Stat. 3392.

[9] *Order on rehearing of Order no. 46,* 44 *Fed. Reg.* 66789 (November 21, 1979).

[10] *Order 63, 45 Fed. Reg.* 1872 (January 9, 1980).

[11] *Order 63, 45 Fed. Reg.* 1872 (January 9, 1980).

NGPA, legalized transportation to alleviate natural-gas shortages. Section 7(c) of the NGA was amended by the 1978 law as follows.

> The Commission may issue a certificate of public convenience and necessity to a natural-gas company for the transportation in interstate commerce of natural gas used by any person for one or more high-priority uses ... in the case of natural gas sold by the producer ... and natural gas produced by such person.[12]

Pursuant to section 608, the FERC issued Order 27 to authorize interstate transportation of direct-sale gas for "essential agricultural users as certified by the Secretary of Agriculture, and all schools, hospitals, and similar institutions," effective April 23, 1979.[13] These recipients could be existing customers, curtailed or not, or entirely new customers within these groups. It was a general program bestowing privileges on certain politically endowed groups.

Order 27 marked the beginning of transportation for the benefit of the general market instead of as an expedient to alleviate curtailment. The market was turning from shortage to surplus, and the FERC recognized the advantage of improved pipeline utilization per se.[14]

Other expansions of direct-sale carriage were made in 1979. Order 30, issued on May 17, established procedures for transporting gas sold by intrastates and LDCs that would displace fuel oil.[15] Section 7(c) certification was required. The impetus of the order was the prospect of oil shortages that gas could help alleviate. Order 52, effective October 5, universalized Order 30 by pre-granting certificates for direct sales and transportation that displaced fuel oil.[16] Transportation was now available for gas destined for "low-priority" boiler-fuel uses as well as "high-priority" industrial and commercial uses—all to alleviate different aspects of the energy crisis.

Another liberalization came with Order 60 of November 30, 1979, that gave blanket authorization for an interstate line to transport system supply for other interstates.[17] Contracts under this authority were limited to two years or less.

Section 603 of the Outer Continental Shelf Lands Act Amendments of 1978 instructed the FERC to facilitate interstate carriage of outer-continental-shelf (OCS) gas owned by an LDC to its service area.[18] Order 92, effective July 15, 1980, expanded expedited transportation for

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[12] Pub. L. 95-617, 92 Stat. 3117 at 3173 (1978).

[13] "*Certification of Pipeline Transportation for Certain High Priority Uses,*" 44 *Fed. Reg.* 24825 at 24827 (April 27, 1979). The maximum term was five years.

[14] "*Certification of Pipeline Transportation for Certain High Priority Uses,*" 44 *Fed. Reg.* 24825 at 24827.

[15] "*Transportation Certificates for Natural Gas for the Displacement of Fuel Oil,*" 44 *Fed. Reg.* 30323 (May 25, 1979). This order was extended by 46 *Fed. Reg.* 30491 (June 9, 1981) and merged into Order 319; see chapter 15, pp. 954–55.

[16] *Order 151, "High-Cost Gas Produced from Tight Formations,"* 44 *Fed. Reg.* 60080 (October 18, 1979). This order was extended past June 1, 1980, by Orders 30-B and 30-D, to May 31, 1981.

[17] *Order 60, "Interstate Pipeline Transportation on Behalf of Other Pipelines,"* 44 *Fed. Reg.* 68819 (November 30, 1979).

[18] Pub. L. 95-372, 92 Stat. 629 at 694 (1978).

such gas under either section 7(c) or section 311 applications.[19]

The foregoing legislation and orders, along with a 1978 federal requirement that offshore pipelines offer nondiscriminatory transportation,[20] offered spot-gas carriage for "priority" industrial uses; "essential" agricultural uses; hospitals, schools, and "similar" institutions; and end-uses that could displace fuel oil. In many cases, transaction-by-transaction certification under section 7(c) of the NGA could be avoided by substituting expedited "blanket" approval.

A modest spot market was created by these transportation orders. Regulation had precluded a spot-gas market in the decades before; regulation now encouraged a spot market to take shape. It was a "stopgap" market to equalize the disparities between the intrastate and interstate markets for short-run relief, however, not an institution that was expected to continue when gas markets got back into balance.

After approximately 8 Bcf were transported in the first two years of the program, volumes diminished as a result of the improved market balance caused by growing supply and declining demand. Section 311, however, was an open-ended, non-experimental vehicle that awaited favorable conditions for regular use.

The Gas Surplus and Industry Responses: 1981–84

Pervasive natural-gas regulation created a legacy of industry disorder. A decade before, it was shortages and statutory allocation; beginning in 1981, the new problem was excess deliverability that interstate pipelines could not market under the provisions of their contracts.

A combination of rising gas prices, declining fuel-oil prices, new base-load coal and nuclear plants, the mild winters of 1981/82 and 1982/83, and an industrial recession significantly depressed demand for natural gas. Gas supply, meanwhile, was increasing because of incentive pricing under the NGPA and incentives under take-or-pay contracts to maximize deliverability from given reserves. For pipelines, lost load necessitated ever-increasing tariffs with fixed costs spread over fewer units, and alternate-fuel customers responded by switching to oil and coal. This also left pipelines with surplus supply, given their high take-or-pay obligations.[21]

Faced with a "death spiral" of increasing prices and decreasing demand, the industry needed a degree of market entrepreneurship foreign to its public-utility status.[22] The serenity of gas-in/gas-out and cost-plus billing would not suffice for pipelines that were caught between

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[19] *Order 92, "Statement of Policy on Distributor Access to Outer Continental Shelf Gas,"* 45 *Fed. Reg.* 49247 (July 24, 1980).

[20] Pub. L. 95-372, 92 Stat. 629 at 638–39.

[21] See chapter 8, pp. 442–44.

[22] Political entrepreneurship, on the other hand, was alive and well to get statutory or legislative relief from the "bad" contracts. President Reagan's unsuccessful Natural Gas Consumer Regulatory Reform Act of 1983, which would have annulled take-or-pay contracts above 50 percent of deliverability, was supported by Tenneco and other troubled interstate pipelines. A second nonmarket strategy was for pipeline companies to unilaterally break contracts and appeal to the FERC for support.

high-take purchase requirements (at high prices in many cases) and unmarketable supply. The job was to tiptoe out of a mine field between high prices on one side and minimum-take provisions on the other, with every self-help move requiring pre-notification of and approval from the FERC.

Contract Remedies

Two early strategies were developed to arrest the related problems of high prices and excess deliverability. One was to enter into "dump-sale" contracts to dispose of excess supply at cost. The second practice was to exercise "market-out" provisions in gas contracts to reduce purchase prices to market levels. This applied to unregulated "high-cost" gas, not regulated vintages for which NGPA ceiling prices also acted as price floors.

In April 1982, Transco reduced the price for unregulated deep gas to $5.00 per Mcf, which was equitably done between affiliated and nonaffiliated production to avoid legal problems. Fifteen of the top twenty interstates followed within a year, and by the end of 1983, deep-gas prices averaged 50 percent below 1981 levels.[23] An estimated 3,100 market-out contract clauses were activated in this period.[24]

Other pipeline practices to mitigate take-or-pay claims were to reinterpret contracts on technicalities to force prices down and take refuge under state prorationing laws (particularly in Texas) that limited withdrawals to "market demand."[25]

Unfortunately for many interstate pipelines, the majority of their gas purchase contracts were not market sensitive even if new contracts were. This predicament led to unilateral take-reduction programs, based on force majeure, by Columbia (summer 1982), United (February 1983), Natural (April 1983), Consolidated (April 1983), and Tenneco (May 1983), which prompted a flood of lawsuits.[26] The "Act of God" contract-out traditionally meant a physical inability to perform because of unforeseen events (equipment failure or weather); it was now conveniently defined to mean an unforeseen change in the business climate (depressed demand and falling prices).

Many interstates began to file for rate decreases in April 1983 for the first time in decades, if not history. It had taken longer, but gas prices were now headed in the same direction as oil prices.

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[23] Other firms were Michigan-Wisconsin (July 1982, $6.00 per Mcf); United (September 1982, $5.72 per Mcf); Tenneco (November 1982, $4.85 per Mcf); Natural (December 1982, $3.80 per Mcf); Florida (December 1982, $5.00 per Mcf); Northwest Central (January 1983, $3.30 per Mcf); Texas Eastern (January 1983, $5.00 per Mcf); Texas Gas (January 1983, $5.00 per Mcf); Transwestern (January 1983, $5.00 per Mcf); Panhandle (February 1983, $4.08 per Mcf); El Paso (March 1983, $5.00 per Mcf); and Colorado (April 1983, $5.00 per Mcf). El Paso, Natural, Northern, Tenneco, Texas Eastern, Transco, and United would drop deep-gas prices lower. U.S. Department of Energy, Energy Information Administration, "Recent Market Activities of Major Interstate Pipeline Companies," January 1984, p. 17.

[24] Jon L. Brunenkant, "State and Federal Take-or-Pay Issues," *Oil and Gas Analyst* (August 1983): 9.

[25] Connie Barlow, "Second- and Third-Tier Natural-Gas Markets," *ARTA Energy Insights* (October 1983): 3.

[26] See chapter 8, pp. 444–47, for further discussion of the take-or-pay problem.

Early Spot-Market Activity: 1981–83

Contractual remedies were not nearly enough. Too many contracts, signed in an era of short supply and under malincentives from public-utility regulation, had inflexible price and take provisions.[27] New programs to turn jurisdictional gas into competitively priced spot gas were required. *Legalized* flexibility had worked against shortages; it now had to work against surpluses.

In late 1980, the FERC began granting case-by-case off-system sales certificates whereby interstate pipelines could take surplus system supply to other markets. The primary motivation for the commission and involved firms was take-or-pay relief. In the first two years of the ad hoc program, nearly 240 Bcf of an authorized 1 trillion cubic feet (Tcf) went to off-system markets.[28]

The worsening problems of surplus supply and take-or-pay liability led to a generic off-system sales program by the FERC in late 1981. Noticing that "now virtually all interstate pipelines have a supply surplus,"[29] the commission authorized interstates to sell excess gas in nontraditional markets if take-or-pay problems were being experienced, existing customers could be fully serviced, the transaction was priced at the higher of the pipeline's average section 102 wellhead price or the pipeline's average load factor rate, coal and other "plentiful" fuels were not displaced, and the incremental revenue benefited other pipeline customers.

Off-system transactions also had to be interruptible, one year or less, and meet a demonstrable need of the buyer. Only new and high-cost gas was eligible for the program. Firm customers, whether residential, commercial, or small industrial, could not participate in the program.

These conditions reflected the concerns of intrastate pipelines about interstate spot-gas competition, interstate customers who did not want low-priced gas to go off system, and the interstates themselves who did not want spot gas to displace system supply in secure markets. Authority was limited to 954 Bcf and expired on June 30, 1982.

Although only 19 percent of the permitted volume was sold, a result attributable to strict regulatory stipulations, take-or-pay relief pointed toward a permanent spot market. The next step came on April 28, 1983, when Transco received permission in an uncontested rate settlement to reduce gas prices to compete with no. 6 fuel oil in threatened markets.[30] The Industrial Sales Program (ISP) hinged on blanket abandonment authority (in place of lengthy

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[27] See chapter 8, pp. 444–45, for the link between the contract problem and government intervention in natural-gas markets.

[28] The program is described in 23 FERC 61306 (1983).

[29] 23 FERC 61305 at 61307. Surplus deliverability was estimated at between 2 and 3 Tcf annually.

[30] See Sheila Hollis, "Notable Recent Developments in Federal Natural Gas Regulation," *Proceedings of the Thirty-Fourth Annual Institute on Oil and Gas Law and Taxation* (New York: Matthew Bender, 1973), pp. 40–41. Developments over the next several years, including a relaxation of pricing requirements to expand off-system sales, are described in J. Richard Tiano and Richard Bonnifield, "The Impact on Gas Distribution Companies of Federally Approved Special Marketing Programs," *Energy Law Journal* 5 no. 2 (1984): 288–90.

case-by-case review) for producers to withdraw dedicated reserves that Transco could reprice at competitive levels (determined by a net-back pricing formula based on monthly surveys of fuel-oil prices and substitution points) and sell to price-sensitive (fuel-switchable) customers.

In return, Transco received a transportation fee in addition to take-or-pay relief. Several months later, the ISP was joined by the Common Carrier Program, under which outside parties matched supplier and buyer and hired Transco for transportation services.

From May to September 1983, Transco averaged 150 million cubic feet (MMcf) per day under its spot-market programs. This amount would have been greater if multiple prices had allowed meeting the competition in distinct markets and the weighted-average-cost-of-gas price floor had been absent. As it was, there was much more supply than market. Nonetheless, the watershed programs benefited all parties, explaining why timely FERC approval was obtained initially.

For Transco, take-or-pay credit and incremental transportation revenues were won. Higher pipeline utilization meant lower rates for all customers, residential and industrial. For producers, unmarketable gas was made marketable, and present money was received instead of uncertain revenue from take-or-pay litigation.[31] For targeted end-users, finally, the preferred boiler fuel of natural gas was made competitive with fuel oil.

Expedited Transportation

The spot market was given a solid transportational footing in the summer of 1983 when the FERC gave blanket certification to end-users to contract with producers, pipelines, and distributors to buy gas and hire an interstate for carriage. Order 234-B sanctified carriage for non-high-priority industrial and boiler-fuel customers (replacing Order 30) *and any end-user* so long as the gas was not dedicated interstate prior to November 8, 1978, and was purchased from an intrastate pipeline or was owned by either an LDC or the purchasing end-user.[32] The term was limited to 120 days.

The two-year "experimental" program, which provided a special $0.05 per million Btu carriage fee for interstates, was intended to make gas competitive with fuel oil and thus increase pipeline throughput, benefit "high-priority" customers who otherwise would pay higher rates, and promote exploration and production. The commission recognized that traditional rolled-in (average-cost) pricing put these price-sensitive gas customers at risk and

[31] 23 FERC 61415 (1983). The proposal reflected not only the entrepreneurial alertness of such Transco executives as president Kenneth Lay but the fact that the company, in the words of chairman Jack Bowen, was "the first in the hospital." *Houston Chronicle,* January 1, 1985, p. 2-1. A decade earlier, Transco had experienced relatively severe curtailment problems, which not only incited many customers to install dual-fuel burners but led Transco into supply contracts with (overly) generous price terms and high take-or-pay levels.

[32] *Order 234-B,* "Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors," 48 *Fed. Reg.* 34872 (August 1, 1983). Order 319-A, "Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors," (48 *Fed. Reg.* 51436 [November 9, 1983]) clarified the requirement that eligible gas had to be internally developed by the end-user.

that only marginal-cost spot-market pricing could rectify the situation.

Order 319 awarded blanket transportation certification to Order 2 (high-priority) uses in place of transaction-by-transaction approval for contracts of less than five years in duration.[33] Eligible for expedited transportation were "high-priority" users; "essential" agricultural users; hospitals, schools, and "similar" institutions; commercial establishments using more than 50 Mcf on a peak day; plants requiring gas for "protection"; and process and feedstock users. This included the system supply of another pipeline and all LDCs. Volumetric limitations established in earlier orders were dropped. The commission noted the difference between the old transportation orders and the new in Order 319.

> A direct sale program can serve a variety of policy objectives. Although these programs were originally designed to be a "stopgap measure" rather than a permanent palliative to curtailment, the emphasis of the programs has shifted.... In the context of present natural gas markets, the primary objective of a direct sale program should be market ordering.[34]

The next commission transportation initiative to facilitate market ordering came with the Special Marketing Programs (SMPs), discussed below.

Spot-Market Expansion: 1983–84

In 1983, Connie Barlow observed, "The interstate pipeline business is fast becoming one of the most attractive management challenges for executives with entrepreneurial leanings—quite a contrast to its dreary utility image of the past."[35] Transco's special marketing program attracted imitators, but opposition slowed commission approval of the new programs. A Tenneco proposal was opposed by Texas intrastate pipelines such as Valero, Delhi, and Texas Oil that feared that freed spot gas would be used for "market-raiding transactions."[36] An application from Columbia Gas encountered stiff regulatory requirements because of industry dissent, which Columbia complained would "effectively preclude transportation of any significant volumes."[37]

Both applications were approved in November 1983 to give Transco competition outside the Blanket Certification Program. Tenneco's Tenneflex program was authorized to market surplus OCS gas if it was priced equal to or above the weighted average cost of pipeline gas.[38] Unlike Transco's ISP, Tenneco's program was a producer program that located buyers

[33] *Order 319 (Phase II),* "Sales and Transportation by Interstate Pipelines and Distributors; Expansion of Categories of Activities Authorized under Blanket Certificate," 48 *Fed. Reg.* 34875 (August 1, 1983). Phase I of the commission's program (*Order 234,* "Interstate Pipeline Certificates for Routine Transactions," 47 *Fed. Reg.* 24254 [June 4, 1982]) gave jurisdictional pipelines a blanket certificate for a variety of activities outside of transportation.

[34] *Order 319,* "Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors," 48 *Fed. Reg.* 34877 (August 1, 1983).

[35] Connie Barlow, "Second- and Third-Tier Natural-Gas Markets," p. 4.

[36] *Inside FERC,* December 5, 1983, p. 3. Other protestants were Mobil Oil and Texas Eastern.

[37] *Inside FERC,* December 12, 1983, p. 1.

[38] 25 FERC 61601 (1983). Tenneflex would become a model for other gas-producer SMP applicants such as Cities Service Oil and Gas, Amoco, and TXP Operating Company (Transco).

and made pipeline arrangements. Columbia's ISP was similar to Transco's with restrictions to limit the program to industrial customers only.[39]

While other producer and pipeline special marketing programs were in the approval process, Transco's ISP ended in November 1983 because of firming oil prices that reduced pressure on gas. The Common Carrier Program continued until March 31, 1984, when both programs expired. Transco's decision not to renew was based on a January 16 FERC ruling that required 100 percent load factor rates as the pipeline carriage fee (the lower the throughput, the higher the rate) and required the gas to be priced no lower than contract gas.[40] Thereafter, "Common Carrier Program-type" transactions under the Blanket Certification Program, predominantly with off-system gas, kept Transco active in the spot market.[41]

The limiting provisions surrounding special marketing programs raised controversy in some gas-industry circles, although they appeased intrastate pipelines and other critics of unregulated spot-market activity. Worthwhile transactions were narrowed for Transco and the more recent ISPs of Columbia; Tenneco (Tempro, December 20, 1983); and Panhandle Eastern and Trunkline Gas (PanMark, March 19, 1984) and later Texas Eastern (TeenMark, June 29, 1984) and El Paso (STP, August 24, 1984).

Only PanMark remained active in the third quarter of 1984. On the producer side, thirteen new programs were approved in 1984, and another six were pending, but only three, Transco's TransMart (July 24, 1984), Cities Service's cost of gas sold (June 29, 1984), and Amoco's SMP (August 20, 1984), registered volumes in the same period. Tenneflex led all pipeline and producer SMPs with nearly half of total period volume.[42] In all, some 150 Bcf of spot gas were sold by SMPs between May 1983 and September 1984, an amount that would have been greater except for regulated producer contracts that could not be released into spot channels.[43]

Spot gas and transportation represented a partial but not total bypass of the LDCs. Once the focal point of gas transactions, the LDCs could now be third-party transporters for gas sales between producers (or marketers) and end-users. In addition to state and federal legalization of transportation, bypass was facilitated by the eradication of minimum bills between

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[39] 25 FERC 61561 (1983).

[40] 26 FERC 61050 (1984).

[41] Transcontinental Gas Pipe Line Corp., "Overview of TGPL's Natural Gas Spot Market Programs: Mechanics and Experience to Date," Houston, Texas., December 31, 1984.

[42] Other approved producer SMPs were ARCO (August 23, 1984); Sun (October 9, 1984); Odeco (January 2, 1984); Champlin (December 17, 1984); ANR (December 17, 1984); and Cenergy (December 17, 1984). Pending producer SMP applications were from Texas Gas, Mesa Petroleum, Diamond Shamrock, American Petrofina, Union Texas, and Conoco. A natural-gas broker, Yankee Resources, also had an application pending. See Interstate Natural Gas Association of America, "Update on Special Marketing Programs," January 1985. These producer SMPs, in contrast to pipeline SMPs, were credited with more competitive pricing because of greater competition at the wellhead and less concern with customer targeting. See U.S. Department of Energy, *Increasing Competition in the Natural Gas Market,* the second report required by sec. 123 of the Natural Gas Policy Act of 1978 (Washington, DC: Government Printing Office, 1985), p. 83.

[43] DOE, *Increasing Competition in the Natural Gas Market,* p. 72; and Connie Barlow, "Second- and Third-Tier Natural-Gas Markets," p. 12.

pipelines and LDCs in mid-1984 that previously locked out spot gas by locking in jurisdictional supply.[44] Total bypass of the LDCs, on the other hand, was achieved when interstates directly connected with end-users.[45]

Not only did onerous provisions reduce SMPs to a small part of the spot-market picture, complaints were heard that restricting the program to industrial customers and discouraging gas-on-gas competition with price floors represented "incremental pricing in reverse." While the NGPA directed higher gas prices toward industrial users, the FERC intended industrial customers to benefit from SMPs to leave residential customers and other captive users with "no alternative but to continue paying the pipeline's uncompetitive and often increasing regular rates, which caused the current load loss problems in the first place."[46]

The call for open competition impressed the FERC, and on September 26, 1984, new conditions were imposed on SMPs that replaced the pricing proviso with a requirement that up to 10 percent of a pipeline's firm-service demand could be raided by another firm's SMP.[47] The FERC's new agenda was to lower prices for *non-alternate*-fuel customers. This introduced gas-on-gas competition with a vengeance, and with most firms fearing deteriorations of take-or-pay positions and lost throughput, only one firm, Texas Eastern, chose to renew its certificate. No volumes were carried.[48]

At the close of 1984, the spot market consisted of jurisdictional (regulated) areas such as gas sold under the Blanket Certification Program and nonjurisdictional (nonregulated) programs such as Transco's Market Retention Program (November 1984), which instructed producers on competitive pricing, and Tenneco's Tenngasco Exchange (October 1984), which set monthly spot-market prices for sellers and buyers. Deregulated gas was primarily involved.

Another entrant into the spot market was the U.S. Natural Gas Clearinghouse, which offered brokerage services to the entire industry to reduce transaction costs. "As a neutrally positioned market maker," Transco's Bowen explained, "the clearinghouse will enable producers and users to satisfy their spot market gas requirements through a single national marketplace."[49] Equity partners were Transco, United Gas, Columbia, Colorado Interstate, Houston Natural Gas, the investment banking house Morgan Stanley, and the law firm of Akin, Gump. Other upstart brokers not affiliated with pipelines making markets in 1984 were Yankee Resources and Citizens Energy.

Another proliferation within the spot-gas market took the form of magazines, newsletters,

[44] Order 380, "Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions," 49 *Fed. Reg.* 22778 (June 1, 1984).

[45] Connie Barlow, "Carriage of Customer-Owned Gas," pp. 11–12.

[46] Glen Howard, "Special Marketing Programs: Incremental Pricing in Reverse," *Natural Gas,* August 1984, p. 21.

[47] 28 FERC 61684 (1984). Abolition of the fuel-switching eligibility rule, the commission noted, was partly to "avoid encouraging uneconomic investment in alternate fuel capability where the new investment is used not so much to utilize the alternate fuel as to qualify for cheaper natural gas." On rehearing, minor amendments were made to the 10 percent rule on December 21, 1984. 29 FERC 61697 (1984).

[48] U.S. Department of Energy, *Increasing Competition in the Natural Gas Market,* p. 72.

[49] "Central Unit Set Up for Spot Gas Sales," *OGJ,* June 25, 1984, p. 32.

consultants, and middlemen capitalizing on a market beginning to escape from a decades-old regulatory straightjacket. With multiple tiers of mispriced gas at the wellhead and similarly mispriced gas at the transmission and distribution levels, any relaxation of regulation offered bountiful opportunities. Arlon Tussing described the situation:

> The potential gains from arbitrage created by this mass of price and rate disparities measure in the tens of billions of dollars annually. They thus create an irrepressible provocation for thousands of entrepreneurially minded gas producers, pipeline and distribution company executives, industrial gas consumers, brokers, traders, and others to find holes in, and ways around, the regulatory and contractual obstacles to a continent-wide price equalization.[50]

The spontaneous development of natural-gas spot markets to combat market disequilibrium changed the face of regulation as well. Tussing continues:

> It is the presence of these hustlers and deal makers that is the most drastic and irreversible change.... The infusion of entrepreneurship into a heretofore stodgy, legalistic, and unimaginative corporate leadership is a competitive genie that will refuse to return to its bottle, regardless of the wishes of state and federal utility commissioners or the members of Congress.[51]

Prior to natural-gas wellhead decontrol on January 1, 1985, the spot market had grown to a $6-billion-a-year industry, representing 15 percent of total U.S. gas consumption.[52] SMPs, because of FERC requirements, supplied no more than 10 percent of the total of nearly 1 trillion cubic feet, but benefits were reaped. In the first year of its SMP, Transco received $150 million in take-or-pay credit, and other firms accounted for several hundred million dollars more through 1984. With a continuing surplus, additional volumes of decontrolled gas under the NGPA, freed jurisdictional supply in the post-minimum-bill era, and new spot-market institutions, including a natural-gas futures market proposed by the New York Mercantile Exchange, continued growth was likely.[53]

The Perils of Regulation

As chapter 29 will substantiate, a recurring theme of this book is that government intervention creates distortions that necessitate relaxed regulation if market order is to reappear. Legalized transportation in the 1970s to arrest shortages and in the 1980s to ease surpluses is an outstanding example of this interventionist dynamic. But while expedited certification and the transportation orders are to be applauded, the market disorder they addressed was government created.

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[50] Arlon Tussing, "Permanent Devolution: The Agonies of Half-Hearted Decontrol in the Natural Gas Industry," unpublished manuscript, 1984, p. 9.

[51] Arlon Tussing, "Permanent Devolution," p. 10.

[52] Benjamin Schlesinger & Associates, "Multi-Client Analysis of Natural Gas Spot Markets: Evolution and Consequences—1984 Update," Bethesda, MD., January 1985, p. I-2.

[53] Elting Treat, formerly the head of New York Mercantile Exchange, described the advantages of natural-gas futures as "an instantaneous price sampling device, a risk management forum for hedging future prices and supplies, and an arena for speculation." *Houston Chronicle,* May 8, 1983, p. 4-10.

Even relaxed regulation created problems compared with less strict regulation and total administrative or legislative deregulation. Shortages in the early 1970s produced no market-oriented relief via direct contracting and transportation. When shortages again cursed interstate markets in the mid-1970s, relaxed regulation proved to be a mild palliative rather than a cure as the curtailments demonstrated. In the 1980s, the FERC's transportation orders were so encumbered with restrictions that, as during the shortages, a palliative replaced a cure. As Connie Barlow summarized:

> Events of the recent past and the present yield indisputable evidence of the limits—and dangers—of regulatory intervention. When the glut first became apparent, interstate pipelines attempted to execute off-system sales. Frustrated by FERC's resolve to impose the WACOG minimum-pricing standard (and worse yet, NGPA Section 102 price equivalency) for the sale of gas from one pipeline to another, companies invented industrial discount rates. Here again, FERC maintained a relatively strong commitment to fully allocated fixed costs and a WACOG price floor for the commodity charge....
>
> More than anything else ... regulators must come to realize that by trying to buck the inevitable, they may do more harm than good to their utility wards and the captive consumers of those utilities.... FERC and state PUC's may attempt to put the proverbial finger in the dike—but they have only so many fingers.[54]

Three major conclusions can be drawn from the early history of the natural-gas spot market: (1) scarcity short-term pricing of natural gas arrived to join long-term regulated contract prices; (2) the market drove pipeline regulation as much as or more than pipeline regulation drove the market after the passage of the Natural Gas Act; and (3) FERC attempts to monitor and shape the spot market were more impeding than encouraging within the framework of legalized transportation.

[54] Connie Barlow, "Second- and Third-Tier Natural-Gas Markets," pp. 19–20.

Appendix 15.2: Natural Gas Import-Export Regulation

In chapter 13, the long history of import and export regulation of petroleum was examined. This appendix turns to natural-gas import and export regulation, the history of which is relatively brief and noncontroversial. After a review of the statutory authority for international-trade regulation of natural gas, important certification issues are reviewed.

Statutory Authority

Statutory authority for natural-gas import and export regulation is found in section 3 of the Natural Gas Act of 1938:

> No person shall export ... or import any natural gas ... without first having secured an order of the Commission authorizing it to do so. The Commission may by its order grant such application ... with such modification ... and for good cause shown, make such supplemental order in the premises as it may find necessary or appropriate.[1]

A year after the NGA became law, an executive order instructed the FPC

> (1) to receive all applications for permits for the construction, operation, maintenance, or connection, at the borders of the United States, of facilities for the ... importation of natural gas ... for foreign countries, and (2) after obtaining the recommendations of the Secretary of State and the Secretary of War thereon, to submit each such application to the President with a recommendation as to whether the permit applied for should be granted, and if so, upon what terms and conditions.[2]

An executive order in 1953 reiterated that licensing deliberations by the FPC for border facilities included a "favorable recommendation of the Secretary of State and the Secretary of Defense."[3] Cold-War politics, in addition to the first call of the domestic gas market, was a factor in this expansion of section 3 authority.

Natural-gas exports were specifically mentioned in the Alaskan Transportation Act of 1976.[4] Section 12 required the president to "make and publish an express finding that such exports will not diminish the total quantity or quality, nor increase the total price of energy available to the United States." This directive reflected gas shortages that plagued many consuming regions across the country.

In the Department of Energy Organization Act of 1977, natural-gas import-export regulation

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[1] Pub. L. 75-688, 52 Stat. 821 at 822 (1938).

[2] Executive Order 8202 (July 13, 1939). Quoted in 11 FPC 4 (1952).

[3] 18 *Fed. Reg.* 5397 (September 3, 1953).

[4] Pub. L. 94-586, 90 Stat. 2903 (1976).

was transferred from the FPC to the newly created FERC within the U.S. Department of Energy.[5] The FERC inherited a vexing problem: whether to permit much-needed imports that were priced well above what the commission found to be "just and reasonable" for domestic gas.

Licensing Decisions

Federal regulation of natural-gas imports and exports affected imports from (and, to a lesser extent, exports to) Canada and Mexico and long-distance tanker shipments of liquefied natural gas (LNG). Most of this activity sprang up in the 1970s when domestic regulation of gas supplies created shortages that imports relieved.

Canada

The first section 3 ruling concerned Panhandle Eastern's 1951 request to export southwestern gas to Canada. The extension was denied because "in view of the demonstrated requirements of customers within the United States and the designed capacity of the Panhandle system (850,000 Mcf daily), no natural gas is available for exportation on a firm basis at this time."[6]

Two years later, the commission approved Tennessee Gas Transmission's application to export 62 MMcf per day of Gulf Coast gas to Toronto and nearby markets.[7] The twenty-year contract was found to have "no material effect" on domestic reserves and, in fact, was well below volumes previously authorized for export to Mexico.[8]

The first import application was approved in 1951 for Montana Power Company to deliver Canadian gas to the Anaconda Copper Mining Company, a war-related metals plant in Montana.[9] Another early application concerned a 400-mile pipeline carrying Canadian gas from Alberta to the Pacific Northwest.

In a controversial 1954 ruling, the application was denied, which opened the door for a 1,400-mile extension of El Paso Pipe Line from the San Juan Basin in New Mexico and Colorado, connecting with Pacific Northwest Pipeline, to the same market.[10] The FPC based its denial on political uncertainties.

> The fullest possible ... protection would not be afforded to any segment of the American people if its sole source of essential natural gas were through importation from a foreign country without some intergovernmental agreement assuring the continued adequacy of its supply. Otherwise, all control ... would be in the hands of agencies of foreign governments whose primary interest would ... always be ... dependent upon public opinion within

[5] 42 *Fed. Reg.* 46267 (September 15, 1977).
[6] Opinion 218, 10 FPC 328 at 339–40 (1951).
[7] Opinion 261, 12 FPC 311 at 330 (1953).
[8] Opinion 261, 12 FPC 311 at 314 (1953).
[9] Opinion 223, 11 FPC 5 (1951).
[10] Opinion 271, 13 FPC 221 at 235 (1954).

that country, rather than upon the interests of American consumers.[11]

The restrictive import policy of the FPC began to be reversed in the late 1950s, and by the late 1960s, the commission routinely approved applications to import Canadian gas to midwestern and northwestern markets. The growth of Canadian imports reflected this fact; by 1970, gas imports had grown from 104 Bcf a decade before to 768 Bcf.[12] With gas shortages over the next years, Canadian exports to the United States increased dramatically, and by 1974, 41 percent of Canada's gas went south.[13]

Concern on the part of Canada's National Energy Board over excessive exports began in 1975, but with only light-handed Canadian interference (unlike Canadian oil exports, which encountered heavy-handed intervention), volumes reached 1 Tcf in 1981.[14] U.S. regulators welcomed imports, but the high price of nearly $5.00 per Mcf was an unpleasant necessity given the alternative of inadequate supply. As of 1984, nineteen authorizations totaling 4.5 Bcf per day, a volume deemed surplus to home consumption, were in force at the (Canadian) regulated price at $4.94 per Mcf.[15] These allowables, significantly increased from the 1970s, were concentrated in California and the central United States.

Mexico

Mexico in the early 1960s began to export gas to the United States, and those exports averaged between 40 Bcf and 50 Bcf annually over the next decade.[16] A pricing dispute initiated by Mexico led to suspension of deliveries to the United States in 1975. Negotiations between Petroleos Mexicanos (PEMEX) and a consortium of U.S. gas suppliers, working through federal authorities, led to a resumption of imports in early 1980.

Another pricing dispute initiated by Mexico resulted in a 23 percent price increase for Mexican gas to $4.32 per Mcf—at parity with Canadian gas—which was reluctantly granted by the Economic Regulatory Administration.[17] Although only a fraction of the amount of Canadian imports, high-priced Mexican gas served as a necessary supplement to domestic supply. As of 1983, only one authorization was in force: a 300 Mcf per day contract priced at $4.94 per Mcf.

The growth of gas imports in the 1960s and particularly in the troubled 1970s, and the increased prices that accompanied this growth, can be seen in table 15.A2-1.

Liquefied Natural Gas

[11] Opinion 271, 13 FPC 221 at 235 (1954).

[12] "Pipeline Gas Supplies," in AGA, *Regulation of the Natural Gas Industry,* 4 vols. (New York: Matthew Bender, 1982), vol. 1, p. 12-67.

[13] Pipeline Gas Supplies," p. 12-67.

[14] David Muchow, "The Gas Industry: 1982–2000," in AGA, *Regulation of the Gas Industry,* vol. 1, p. 6-18.

[15] Canadian export regulation is guided by two principles: (1) exports should not be priced below domestic sales, and (2) export quantities should be surplus to home consumption.

[16] "Pipeline Gas Supplies," p. 12-71.

[17] "Pipeline Gas Supplies," p. 12-72.

High-priced imports, the wolf at the door of domestic natural gas regulation, were most clearly seen with LNG from Algeria (Sonatrach) and Indonesia (Pertamina). LNG reflects a capital-intensive process whereby natural gas is liquefied at extremely cold temperatures (minus 260°F) to condense the methane to 1/600 of its normal volume. It is then transferred from LNG terminals to special tankers for carriage to other LNG terminals where it is revaporized at pipeline connection points.

Table 15.A2-1

NATURAL-GAS IMPORTS AND EXPORTS: 1960–84

Year	Imports: Total Imports (MMcf)	Imports: Avg. Price ($/Mcf)	Exports: Total Exports (MMcf)	Exports: Avg. Price ($/Mcf)	Net Imports (MMcf)
1960	155,646	–	11,332	–	144,314
1961	218,860	–	10,747	–	208,113
1962	401,534	–	15,814	–	385,720
1963	406,204	–	16,957	–	389,247
1964	443,326	–	19,603	–	423,723
1965	456,394	–	26,132	–	430,262
1966	479,780	–	24,639	–	455,141
1967	564,226	–	81,614	–	482,612
1968	651,885	–	93,745	–	558,140
1969	726,951	–	51,304	–	675,647
1970	820,780	–	69,831	–	750,949
1971	934,548	–	80,212	–	854,336
1972	1,019,496	0.31	78,014	0.31	941,482
1973	1,032,901	0.35	77,169	0.34	955,732
1974	959,284	0.55	76,789	0.55	882,495
1975	953,008	1.21	72,675	1.21	880,333
1976	963,768	1.72	64,710	1.72	899,058
1977	1,011,002	1.98	55,626	1.98	955,376
1978	965,545	2.13	52,533	2.13	913,012
1979	1,253,383	2.49	55,673	2.49	1,197,710
1980	984,767	4.28	48,731	4.28	936,036
1981	903,949	4.88	59,372	4.88	844,577
1982	933,336	5.03	51,728	5.03	881,608
1983	918,407	4.78	54,639	4.78	863,768
1984	843,060	4.08	54,753	4.08	788,307

SOURCE: U.S. Department of Energy, Energy Information Administration, *Natural Gas Monthly,* August 1992, p. 10; and American Gas Association, *1986 Gas Facts* (Arlington, Va.: 1987), p. 34; and American Gas Association, *1967 Gas Facts* (Arlington, Va.: 1968), p. 110.

LNG was first produced and commercially stored in the United States in 1939. Two decades later, transatlantic shipments commenced from the United States to Canvey Island, England. Small LNG imports began in 1968.

In March 1972, the FPC ruled that liquefied gas came within the meaning of the NGA and approved the first major LNG import project.[18] The commission also assumed jurisdiction over all LNG-related facilities—unloading terminals, storage areas, and regasification plants.[19]

Two major LNG cases in the 1970s attracted controversy because the FPC approved contract prices that were approximately double regulated domestic prices. One case concerned a 1970 application by Columbia LNG Corporation, Consolidated System LNG Company, and Southern Natural Gas Company for El Paso Natural Gas to purchase gas (liquefied in a $250-million plant owned by the Algerian government), ship it in special tankers to the United States, and regasify it for sale to Columbia, Southern, and Consolidated for interstate transportation and consumption.[20]

FPC approval was given in June 1972 at $1.00 per Mcf, a rate two to three times the weighted average cost of gas of the three pipelines.[21] The irony of cost-based regulation, which created domestic-supply problems that created the demand for high-cost LNG, was explained by Commissioner Rush Moody.

> This inequity results from ... cost-based pricing as the foundation for producer regulation. It is this system of regulation which produces discrimination against the lower cost energy source.... Cost-based regulation will encourage the capital intensive source, and will always favor that source which is most difficult to bring to the market; the more the importers spend on transport and processing facilities, the greater the dollar return.[22]

The uncomfortable implications of the entire LNG project, despite his approval, led Moody to add:

> We place LNG customers, and the shareholders of three major pipelines, in dependence on a foreign power. Unilateral price escalation or interruption in service may be expected when foreign national interest so dictates. Only one force can effectively operate to hold down the costs of foreign supplies. We must have vigorous and effective competition from domestic producers.[23]

On rehearing, a new issue threatened the project—use of incremental over rolled-in pricing, which targeted the record high prices charged certain consumers.[24] This requirement threatened the project, and the sponsors filed suit and persuaded the court that the FPC went beyond their authority by requiring marginal-cost pricing.[25] The commission on remand

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[18] Opinion 613, Distrigas Corp., 47 FPC 752 (1972); and Opinion 613-A, 47 FPC 1465 (1972).

[19] Distrigas Corp., 49 FPC 1145 (1973).

[20] The Algerian plant was 90 percent financed by the Export-Import Bank. Total U.S. Export-Import Bank involvement exceeded $400 million. *Energy Crisis,* ed. Lester Sobel, 4 vols. (New York: Facts on File, 1974), vol. 1, pp. 182–83.

[21] Opinion 622, 47 FPC 1624 (1972).

[22] Opinion 622, 47 FPC 1624 at, p. 1654.

[23] Opinion 622, 47 FPC 1624 at p. 1653.

[24] Opinion 622-A, 48 FPC 723 (1972).

[25] *Columbia LNG Corporation* v. *FPC,* 491 F.2d 651 (5th Cir. 1974).

approved rolled-in pricing in early 1977, and the project began after a six-year delay.[26]

A similar pricing dispute arose from a November 1973 request by Trunkline LNG Corporation to approve an import price that was double the price of domestic supply. The commission first required incremental pricing and suggested that the same rate design apply to all LNG projects.[27] After a storm of dissent—indeed, incremental pricing would either price LNG out of the market or seriously discriminate against certain users—an amendatory opinion was issued on June 30, 1977, to allow rolled-in pricing with regular curtailment contingencies.[28]

Licensing delays interfered with much-needed imports at the height of domestic-gas-supply emergencies.[29] Federal regulators were faced with a self-imposed regulatory dilemma—domestic shortage or program-defeating imports. The attorneys of one of the importers involved described the government's attitude as '"wavering,' 'uncertain' in many cases, and 'largely negative' toward LNG."[30]

With an almost revengeful attitude, Department of Energy officials would turn against LNG imports when the gas emergency lightened.[31] In late 1978 and early 1979, energy czar James Schlesinger announced that LNG as a supply source was "at the end of the priority line," and two Algerian LNG applications were denied by officials because of an alleged lack of "overriding national or regional need for this gas."[32]

With increased volumes blocked by U.S. regulators, the Algerian government sought to increase revenue by again re-negotiating higher prices with El Paso. A December 1979 renegotiation set the price at $1.95 per Mcf, with scheduled increases to $2.54 per Mcf in late 1980, but now the National Liberation Front government desired $6.11 per Mcf. El Paso brought in energy regulators to handle negotiations, and when they reached an impasse, shipments stopped on March 31, 1980. El Paso was losing $7 million a day, and after the seventh negotiating session failed, the company announced a $365.4-million writeoff covering seven LNG tankers and associated regasification facilities.[33] Commissioner Moody's 1972 warning about the perils of LNG imports came true with a vengeance.

Despite the El Paso debacle, LNG imports continued from Sonatrach to Everett, Massachusetts (Distrigas Corp.), and in September 1982, Panhandle Eastern began to receive LNG from Algeria, pursuant to a 1975 contract, priced at $3.92 per Mcf ($6.65 per Mcf landed). Given falling prices and surplus domestic gas, pressure from customers and

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[26] Opinion 786, 57 FPC 354 (1977).

[27] Opinion 796, 58 FPC 726 (1977).

[28] Opinion 796-A, 58 FPC 2935 (1977).

[29] For regulatory delay problems of two California utilities desiring to purchase Indonesian LNG, see "A Funny Thing Happened on the Way to LNG," *Forbes,* September 18, 1981, pp. 52–56.

[30] "Pipeline Gas Supplies," p. 12-87.

[31] By analogy, LNG imports (and Canadian and Mexican gas imports) can be likened to the messenger with bad tidings who bears the brunt of the audience's (the regulators') anger.

[32] See David Muchow, "The Gas Industry—1982–2000," vol. 1, p. 6-25.

[33] "A Squeeze on LNG to Force up Prices," *Business Week,* July 7, 1980, p. 33; and Alexander Stuart, "El Paso Comes in from the Cold," *Fortune,* March 23, 1981, pp. 55–56.

legislators to amend the contract kept the pricing issue alive. Shipments continued at Panhandle's $580-million facility at Lake Charles, Louisiana.

With new gas-market conditions, pricing and other issues became vital to companies trying to remain competitive with substitute fuels in industrial markets. A policy announcement in early 1984 by the Department of Energy noted highly competitive gas markets and abolished federally set border prices to allow private contracting so long as "competitive" and in the "public interest."[34]

The guidelines applied to new contracts, including fourteen pending applications for Canadian gas and two pending Algerian LNG applications. Import contracts remained regulated, but the burden of proof was shifted from applicants to intervenors. Combined with partial export deregulation on the Canadian side, growing gas imports into the United States from the north were evident as of 1984 with promise for greater volumes in the future.

Although less known, the United States was also an exporter of LNG. In 1967, Marathon Oil and Phillips Petroleum entered into a fifteen-year contract to supply several companies in Tokyo, Japan, with LNG from the North Cook Inlet and Kenai fields in Alaska. The first shipment arrived in Tokyo on November 4, 1969.[35] While Alaskan exports had remained steady since the early 1970s, energy analysts lamented the fact that North Slope gas, estimated at 10 percent of total reserves, had not been made available for export.[36]

With restricted gas exports in the absence of a presidential finding, and the uneconomical prospects of the proposed Alaska Natural Gas Transportation System, recycling and flaring were the only alternatives. Without legislative impediment, a gas pipeline to Valdez (next to the Trans-Alaskan Pipeline System) or to the Kenai Peninsula (recommended by the Governor's Economic Committee on North Slope Natural Gas) was the most logical choice with Japan, which already had LNG facilities, and other Pacific Rim outlets as destinations.[37]

The rise and decline of LNG imports compared to LNG exports can be seen in table 15.A2-2.

Table 15.A2-2
LNG FOREIGN TRADE 1969–84 (MMcf)

Year	Imports[a]	Exports[b]	Net Imports
1969	0	2,982	(2,982)
1970	757	44,257	(43,500)
1971	2,933	50,231	(47,298)

[34] 49 *Fed. Reg.* 6684 (February 22, 1984).

[35] Robert L. Hartig and John K. Norman, "Production, Conservation, and Utilization of Natural Gas in Alaska," *Natural Resources Lawyer* 3, no. 4 (November 1970): 699.

[36] A Heritage Foundation study identified a North Slope LNG industry as a potential "catalyst for establishing a stable industrial base in the 49th state." Milton Copulos, S. Fred Singer, and David Watkins, "Exporting Alaska's Oil and Gas," Heritage Foundation Backgrounder no. 248, February 22, 1983, p. 17.

[37] See the discussion in Stephen Eule and S. Fred Singer, "Export of Alaskan Oil and Gas," in *Free-Market Energy: The Way to Benefit Consumers,* ed. S. Fred Singer (New York: Universe Books, 1984), pp. 118–43.

1972	2,262	47,882	(45,620)
1973	4,055	48,346	(44,291)
1974	0	50,258	(50,258)
1975	4,893	53,002	(48,109)
1976	10,155	49,779	(39,624)
1977	11,896	51,655	(39,759)
1978	84,422	48,434	35,988
1979	252,608	51,289	201,319
1980	85,850	44,732	41,118
1981	36,830	55,929	(19,099)
1982	55,136	49,861	5,275
1983	131,124	52,857	78,267
1984	36,191	52,840	(16,649)

SOURCE: U.S. Department of Energy, Energy Information Administration, *Natural Gas Monthly,* August 1992, pp. 10–11.

[a]From Algeria and, to a small extent, Canada.

[b]To Japan from Alaska.