ECONOMIC RESEARCH REPORTS

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R.R. #89-17 July 1989

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Revised
March 1989

The authors gratefully acknowledge support from the C.V. Starr Center for Applied Economics.

ABSTRACT

THE STRUCTURE OF TECHNOLOGY, SUBSTITUTION, AND PRODUCTIVITY IN THE INTERSTATE NATURAL GAS TRANSMISSION INDUSTRY UNDER THE NATURAL GAS POLICY ACT OF 1978

The purpose of this paper is to examine the production technology and cost structure of the interstate natural gas pipeline industry under partial price deregulation. We have constructed a new panel of 24 interstate pipeline companies over the period 1977-1985. We employ a variable cost function to estimate scale elasticities, substitution possibilities, and technical and productive change. Empirical results indicate substantial long-run economies of scale in the natural gas pipeline industry, considerable long-run substitution among most inputs, and a marked decline in total factor productivity while the industry was regulated by the Natural Gas Policy Act of 1978.

I. Introduction

The 1978 Natural Gas Policy Act (NGPA)[1] instituted partial and gradual decontrol of natural gas well-head prices. However, ramifications of the NGPA were not limited to the field market; significant effects have been felt downstream in the transmission and distribution industries also. The pressures of rising average price and falling demand have placed considerable stress on the institutions and traditional transactional arrangements of the natural gas transmission industry.

Deregulation of the airline and trucking industries has been heralded as a success in terms of increased competition, efficiency, and lower costs.[2] Whether or not partial deregulation of natural gas well-head prices has or will result in greater competition and efficiency remains to be determined. Since the transmission industry is characterized by significant economies of scale, it has been argued that the industry will revert to its pre-1938 highly concentrated and monopolistic structure in the absence of regulatory constraints. Proponents of regulation have pointed to the large number of mergers that have occured in the airline, trucking, and now transmission industry since deregulation.[3] On the other hand, those in the industry contend that

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[1]Natural Gas Policy Act of 1978, U.S. code, Supp. 5, Title 15.

[2]See, for example, Johnson (1985), Sickles, Good, and Johnson (1986), Friedlaender, Chaing, and Spady (1981), and Wang Chaing and Friedlaender (1985).

[3]Federal antitrust officials have intiated several investigations as to whether "...consolidation in the gas industry will end up hurting customers." by limiting competition and preventing the shipment of the least cost gas to customers; see Pasztor (1986).

mergers and takeovers have occurred because firms were poorly managed and inefficient. Increased suppliers, customers, operating flexibility, and efficiency have been cited as the motivation behind the mergers and takeovers.[4]

The purpose of this paper is threefold. The first is to analyze the cost structure of the interstate pipeline industry since the passage of the NGPA, using a newly constructed panel of twenty-four firms. We are aware of no empirical studies on the impact of the NGPA on the natural gas interstate transmission industry at the firm level. Particular attention is focused on the elasticity of scale, the substitution possibilities among inputs, and the rigidities in the production process due to the presence of quasi-fixed inputs. Second, the rates of technical change and total factor productivity during the years 1978-85 are examined. Finally, we examine the effects of the NGPA partial price decontrol relative to total well-head price decontrol.

The plan of the paper is as follows. A brief overview of conditions in the industry leading up to and through the sample period is provided in Section II. The restricted cost model used to analyze the transmission industry is described in Section III. Section IV describes the data base which we constructed for this study. Estimation results and the comparison of partial vs. total price decontrol are contained in Sections V and VI respectively. Concluding remarks are in Section VII. A more detailed descrip-

[4]The economic benefits resulting from consolidation of the transmission industry have been put forth by numerous industry executives and outside analysts. For examples, see Burrough (1985), Moffett (1985), Norman (1986), and Shook (1989).

tion of the data sources is contained in the Appendix.

II. Transmission Industry Structure and Its Regulation

The U.S. natural gas industry can be viewed as three vertically linked industries: production, transmission, and distribution. The industry's structure has been greatly influenced by the requirements of the technology, e.g. the need for eminent domain authority to cross private and municipal property to lay pipes and heavy capital investment in long- lived assets promoted the development of vertically integrated local monopolies. By the early 1880s State and municipal authorities established rate of return regulation over local transmission firms. As technology advanced, pipeline systems expanded beyond state borders and the modern day interstate system develped. Since the U.S. Constitution prohibits State and local authorities from regulating or interfering with interstate trade, the public demanded Federal regulation of interstate transmission to curb monopoly behavior. In 1938 Congress passed the Natural Gas Act (NGA) and the Federal Power Commission was created. The FPC, and its successor the Federal Energy Regulatory Commission (FERC), was enpowered to certify the construction, modification, and abandonment of interstate pipeline facilities, and to review interstate pipelines' operating and maintenance costs in order to establish transport rate schedules and city-gate prices which would allow pipelines to earn a "fair" rate of return on investment but eliminate the capture of monopoly rents. Regulation of natural gas producers, distributors and intrastate pipelines was given to State authorities. However, in 1954 Federal price regulation was extended to the well-head.[5] The 1938 NGA was highly successful in promoting the development and consumption of low cost natural gas throughout the U.S. for 35 years, due largely to the abundant quantities of easily accessible natural gas.

The entire picture changed in four years, 1973-76. The 1973 oil price shock had a direct impact on the demand for natural gas and its transport. Energy consumers began switching from oil based fuels to natural gas. The NGA prevented the well-head price of gas sold to interstate markets from rising with demand, while the well-head price of gas sold in intrastate markets was unregulated and free to respond to market conditions. A dual market soon developed. By the late 1970s the flow of gas into the interstate market was so restricted that substantial curtailments in deliveries to industry and residential customers resulted. Congress passed the Natural Gas Policy Act of 1978 in an effort to renew the flow of gas by partially decontrolling the well-head price of natural gas. The price of natural gas shot up dramatically, increasing by 218 percent by 1985.[6] Natural gas consumption declined in reaction to the rapid price increase, as did the transport of natural gas. Thus the natural gas transmission industry suffered both a drop in demand for its product and a

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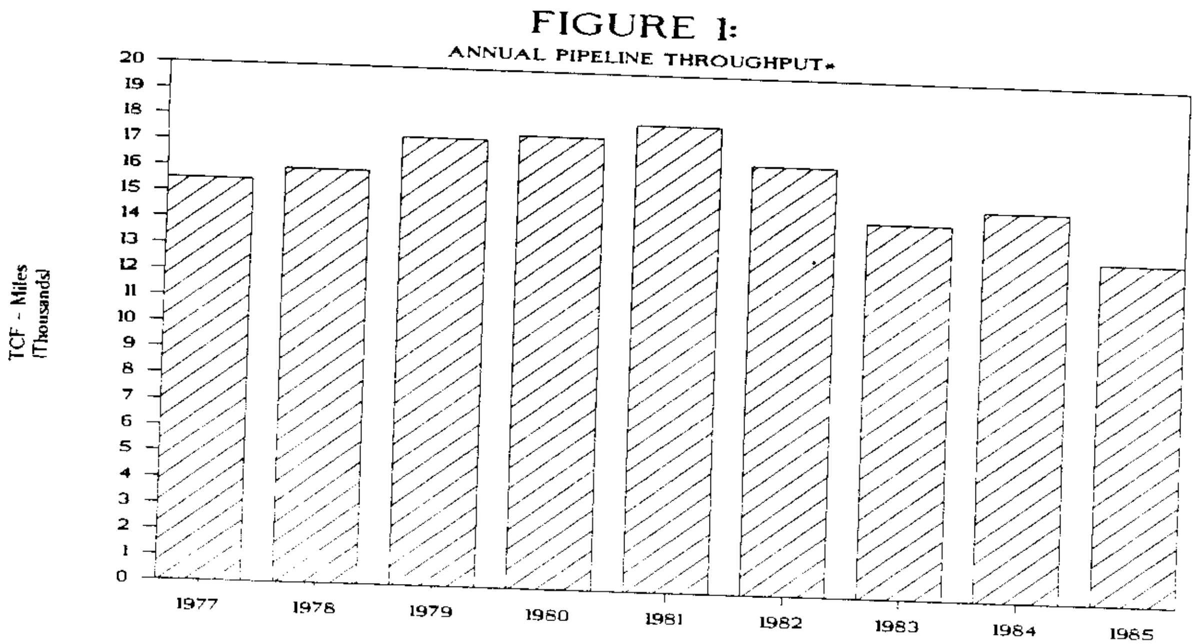
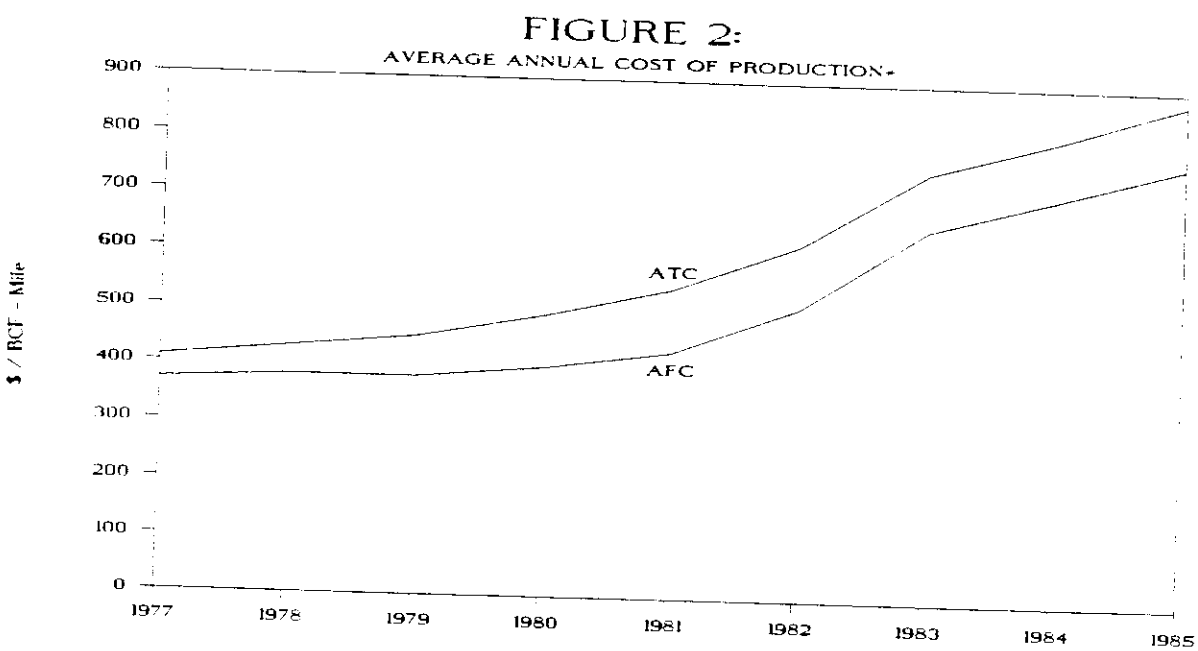
[5]Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 1954. The U.S. Supreme Court ruled that the NGA required federal oversight of all field sales of natural gas destined for interstate commerce.

[6]The 1977 pre-NGPA price for marketed natural gas was $.79 per thousand cubic feet and $2.51 in 1985. For the firms in the sample the price of natural gas used for transmission increased by 215 percent.

sharp increase in the price of energy used in production.

Figure 1 shows the level of production (throughput) by year. Figure 2 illustrates how average total cost (ATC) and





*Based on sample data.

averaged fixed cost (AFC) increased steadily each year.

The NGPA instituted gradual and partial price decontrol of natural gas sold by producers to interstate markets. This compromise legislation was designed to diminish the price inequality between intra- and interstate markets by allowing a portion of the interstate market to reflect market conditions and to increase competition and efficiency in the interstate transmission industry. However, deregulation was to be gradual to avoid excessive price shocks and partial to maintain the original regulatory objective of preventing monopoly rents from accruing to producers and transporters of low cost gas. Ceiling prices and escalation schedules for various categories of gas were based upon well vintage, commitment to intra- or interstate market, type of geological formation, rate of production, and provisions of existing gas contracts. The objective was for gas prices to reflect production costs and to insure an ample supply of gas. By 1985 approximately 60 percent of flowing gas was free of well-head price regulation. Although the interstate pipelines remain under rate-of-return regulation, there have been continuing calls for further deregulation, including total well-head price decontrol, unbundling of services, and open, nondiscriminatory arrangements to replace the traditional merchant and contract carrier roles of pipeline companies. With our model we can determine the effects of the current partial decontrol on the structure of production and productivity of the transmission industry and compare this to the case of total well-head price decontrol.

III. The Model

There are a number of reasons for estimating a restricted (variable) cost function rather than an unrestricted (total) cost function for the natural gas transmission industry. The primary reason involves identifying the existence of temporary equilibrium, in contrast to long-run equilibrium, due to the presence of quasi-fixed inputs in the production process. Temporary disequilibrium may occur when unexpected demand shocks lead to under- or overutilization of capacity and/or when factor price(s) change suddenly. There has been substantial change in relative prices of some inputs used by the transmission industry, due largely to the partial deregulation of natural gas well-head prices. These changes have placed considerable stress on the institutional and contractural arrangements within the industry and have altered the behavior of individual firms.

A number of other studies, based on the restricted cost function, have demonstrated the importance of correctly distinguishing between temporary and long-run equilibrium. Morrison (1986) and Slade (1986) explored the implication of temporary equilibrium for productivity growth analysis, focusing on the impact of non-constant returns to scale, the degree of substitution between variable and fixed factors, and the cost share of the fixed input. Temporary equilibrium analysis has been applied to a number of industries with one or more quasi-fixed inputs, including U.S. manufacturing (Morrison, 1986 and Hazilla and Kopp, 1986), telecommunications (Shankerman and Nadiri, 1986), and agriculture (Brown and Christensen, 1981).

Previous analysis of the natural gas transmission industry's production function (Sickles and Streitwieser, 1988) suggest there has been a marked decline in productivity during the 1980s. This decline in productivity may be overestimated as our production function based analysis assumed that producers were in long-run equilibrium when, in fact, they may have been in temporary, or short-run equilibrium due to the short-run fixity of some factor inputs (Berndt and Fuss, 1986). For the natural gas transmission industry the pipeline configuration, once in place, is difficult to alter.[7]

The industry's adjustment to the change in regulation has been more disruptive than anticipated and is not yet complete. We believe an analysis based upon temporary equilibrium is more appropriate than one based on long-run equilibrium and will yield more insightful conclusions regarding the true impact of the NGPA.

We assume that the industry is cost-minimizing due to market forces and not FERC regulation. All input prices are assumed to be exogenously determined and not influenced by firm behavior.[8]

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[7]Pipeline configuration includes the pipe diameter, length, and location, and the number and location of compressor stations.

[8]We argue that the industry does have the incentive to cost minimize, particularly in the short-run. FERC regulators do scrutinize the costs of the firm during the rate hearing. Costs are required to be well-documented and reasonable; FERC has been known to disallow some costs. More importantly though, the rate regulation does not guarantee the firm will earn the allowed rate of return; it merely makes it possible. Any shortfall or excess is considered a windfall loss or gain. Thus, once the rate structure is set, the firm has every reason to minimize costs in order to maximize its return. Furthermore, regulatory lag can impose some discipline on the pipelines as they are often unable to obtain approval of new costs and are unable to adjust their rates upward without a new ruling. There have been very few formal rate hearing cases during the period of this analysis.

Use of a cost function requires that output also be exogenously determined, as opposed to being endogenous for the production function. In most regulated industries the regulator sets the output price(s) and requires the firms to satisfy the corresponding demand. This is true for the natural gas transmission industry where FERC established the transport rate schedules on a firm-by-firm basis. The assumptions necessary for estimation of a cost function that represents the industry's production technology appear to be well-suited for this industry.

A translog restricted cost function is used to model the short-run equilibrium. Dummy variables are used to represent three different regulatory epochs: one for the years before the NGPA went into effect (1977-78), a second for the years after the NGPA was passed, but before FERC Order 436 (1979-84), and a third for 1985 when FERC Order 436 was effective and the natural gas spot market was formed.[9]

Given the assumed exogeneity of output and input prices the short-run cost-minimizing problem for the firm is to solve

$$\min \Sigma w_i X_i \qquad \text{subject to } H(Y,X;t) = 0. \tag{1}$$

The solution is the short-run variable cost function given by:

$$CV = G(Y, w_1, w_2, X_3, X_4; t) \tag{2}$$

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[9]FERC Order 436 allows for <u>voluntary</u>, non-discriminatory open transport by pipelines, rather than as merchants and carriers. Few pipelines have received and accepted an Order 436 ruling; most still operate under Section 311 of the NGA.

where Y is the output,[10] measured in billion cubic feet-miles of gas transported, w_1 and w_2 are the factor prices of the variable inputs labor and energy respectively, X_3 and X_4 represent the quantity of quasi-fixed capital inputs, compressor horsepower and pipelines respectively.[11] G is homogeneous of degree one, non-decreasing, and concave in the factor prices w_i, nonincreasing and convex in the levels of quasi-fixed factors X_h, and nonnegative and nondecreasing in output Y.

Although labor is not a fixed input per se, neither is it totally variable. The labor required to operate and maintain the compressor stations and pipeline itself are directly proportional to the length of the line and the number and size of compressor stations. These personnel are necessary regardless of the level of throughput in the pipeline.[12] Administrative labor require-

[10] We model the natural gas transmission industry as a single output industry. Cost data is net of purchased gas expenses. This format allows us to focus on transport services as the product, net of the firms' merchant activities. Although FERC distinguishes three major categories of transport (sales for resale, mainline sales, and transport for others), these are distinctions for regulatory purposes only. Customer classification has no impact on the technology and cost of transmission.

[11] Our measure of compressor services is the total compressor horsepower available to the firm, i.e. the manufacturer's horsepower rating for every compressor unit installed along the pipeline, regardless of the level (hours) of operation. The level of compressor operation varies directly with throughput. Throughput can be increased by adding additional compressors at existing stations, though with decreasing returns to horsepower.

[12] Cookenboo, Jr. (1955) discusses the variable and fixed costs of operating oil pipelines. The arguments apply equally well to natural gas pipelines.

ments are much less rigid.[13]

The translog approximation to G, which can be viewed as a second-order logarithmic approximation to an arbitrary twice differentiable transformation surface (Christensen, et al. 1973), is:

$$\begin{aligned} \ln CV = {} & \beta_0 + \alpha_y \ln Y + \tfrac{1}{2}\gamma_{yy}(\ln Y)^2 + \Sigma\alpha_i \ln w_i + \\ & \tfrac{1}{2}\Sigma\Sigma\gamma_{ij}\ln w_i \ln w_j + \Sigma\alpha_k \ln X_k + \tfrac{1}{2}\Sigma\Sigma\gamma_{hk}\ln X_h \ln X_k + \\ & \Sigma\gamma_{yi}\ln Y \ln w_i + \Sigma\gamma_{yk}\ln Y \ln X_k + \Sigma\Sigma\gamma_{ik}\ln w_i \ln X_k + \\ & \delta_t T + \tfrac{1}{2}\delta_{tt}T^2 + \gamma_{ty}T\ln Y + \Sigma\emptyset_m DE_m \end{aligned} \qquad (3)$$

where DE_m = 1 for regulatory epoch m,
0 otherwise
m = 2, 3.

Linear homogeneity in prices requires that:

$\Sigma\alpha_i = 1$

$\Sigma\gamma_{ij} = 0$ for j = 1,2

$\Sigma\gamma_{ik} = 0$ for i = 1,2;

symmetry requires that:

$\gamma_{ij} = \gamma_{ji}$ for all i,j

$\gamma_{kh} = \gamma_{hk}$ for all k,h.

Monotonicity and concavity conditions are not imposed locally in estimation, but are tested for after estimation. Given exogenous input prices, w_i, and utilizing Shephard's Lemma, first order conditions describing the cost minimizing production of Y are:

$$M_i = w_i X_i / \Sigma w_i X_i = \partial \ln CV / \partial \ln w_i \qquad (4)$$

[13] The labor input for our sample increased by 16.1 percent over the first five years, and then declined by 14.4 percent in the next four years. In contrast, two capital inputs increased by 3.5 percent and 4.8 percent over the first five years, and increased by only .1 percent and 1.1 percent during the next four years. This demonstrated flexibility in labor supports our treatment of labor as a variable input.

where M_i is the variable cost share for variable input X_i. For the translog restricted cost function the share equations take the form:

$$M_i = \alpha_i + \Sigma\gamma_{ij}\ln w_j + \gamma_{yi}\ln Y + \Sigma\gamma_{ik}\ln X_k \qquad i = 1,2. \quad (5)$$

Lau (1978) defines the shadow value for a quasi-fixed input as $-\partial G/\partial X_k = Z_k$, which is the cost savings associated with a one-unit relaxation of the fixed factor constraint. If w_k is less than Z_k the firm desires more of the fixed factor than is available in the short-run. For purposes of estimation, Morrison (1985) suggests adding the "shadow share" equations, $-\partial \ln G/\partial \ln X_k = Z_k X_k/CV$, to the model. The shadow price, Z_k, is the real rate of return or ex-post value of the fixed input X_k and is generally derived as the residual between revenues and variable costs. In the case of more than one fixed input the sum of the shadow shares can be estimated if there is no clear method for allocating the residual between fixed inputs, i.e. $\Sigma Z_k X_k/CV = (PY - CV)/CV$. Rather than use the sum of the shadow shares, we allocate the residual between compressor and pipeline capital services based on the ratio of book value cost and operating costs of compressors to pipelines. The shadow share equations for the restricted translog cost function take the form:

$$M_k = -[\alpha_k + \Sigma\gamma_{ik}\ln w_i + \Sigma\gamma_{hk}\ln X_h + \gamma_{yk}\ln Y]. \quad (6)$$

Regularity conditions imply the shadow price and shadow share equations be positive.

Although we are estimating the restricted cost function, our objective is to describe the long run production process. As shown by Caves, Christensen, and Swanson (1981), we are able to derive various characteristics of production from the restricted cost function. The short-run total cost function is written as $CS = CV + \Sigma w_k X_k$, where w_k is the market price of quasi-fixed factor X_k. The optimal use of the fixed factor is defined by the envelope condition $-\partial G/\partial X_k = Z_k^*$ and the optimal level of the fixed input is implied by $X_k^* = g(w,Y,Z^*)$. Thus, the long run cost function is represented by $C = H(w,Y,Z^*)$.

For the present analysis, we assume that firms exhibit both short-run and long-run static equilibrium; that the level of output in the short run is the optimal long run output also. This means the firm does not desire to alter its quantities of fixed factors ($X_k = X_k^*$), the shadow prices equal the market prices for each fixed factor ($Z_k^* = w_k$), and the short-run cost function, CS, equals the long-run cost function, C.[14]

IV. The Data

The technology of the natural gas pipeline industry is fairly simple: natural gas is compressed and transported from producing to consuming regions via long distance pipelines.[15] The firms also acts as a merchant in the majority of transactions

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[14]The characteristics of technology degenerated to meaningless results when we did not assume long-run static equilibrium and include the shadow share equations in the model; the shadow price for compressor capital services was negative and the long-run returns to scale indicated decreasing returns to scale (.056).

[15]Transport for others is becoming an important activity for the transmission industry, increasing from 17.3 percent (1977) to 36.7 percent (1985) of the volume of gas transported by the firms in our sample. One company, Columbia Gulf Pipeline, engages exclusively in transport for others.

(sales for resale and mainline sales). The major factor inputs are the pipeline itself, compressor stations to regulate the flow of gas, energy to fuel the compressors (primarily natural gas), and labor.

Data were collected on twenty-four major[16] interstate natural gas pipeline companies for nine years, 1977-1985. Nearly all data are extracted from the firm specific FERC Form-2:Annual Report of Major Natural Gas Pipeline Company or the Annual Statistics of Interstate Natural Gas Pipeline Companies, both available from the Federal Energy Regulatory Commission.

Output and input quantites and prices are derived following the basic format of Aivazian, et al. (1987). Total output is measured in billion cubic feet-miles. The total amount of gas delivered (bcf) to local distribution companies, industrial customers, and gas transported for others multiplied by the distance (miles) transported.[17] The quantity of labor is calculated by multiplying the total number of firm employees by the ratio of transmission labor expenses to total labor expenses. The quantity of energy consumed in production is measured by the thousand cubic feet (mcf) of natural gas used by the firm.

Two measures of capital are used. Total horsepower rating of all compressors in place on the transmission lines represents

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[16]Major interstate natural gas pipeline companies are those which have combined gas sales for resale, transport, or storage (for a fee) that exceed 50 billion cubic feet/year. Thirty-three companies met this criteria in 1980.

[17]Aivazian, et al. did not include transport for other in their measurement of output. We have included it here because of its increasing importance to the industry.

compressor station services. Pipeline capital services are measured in terms of the tons of steel of transmission pipelines. The quantity of pipeline capital is determined by the miles of transmission lines multiplied by the square of the (weighted) average diameter, multiplied by the proportionality constant developed by Callen (1978).[18]

The price of labor and energy are derived by dividing total labor and energy expenses by their respective quantities. A value added method is used to derive the user cost for capital services. First, labor and energy expenses were netted out of total revenues from sales for resale, industrial sales, and transport of gas of others. Second, the cost of gas is subtracted out. The residual is allocated between compressor and pipeline services based on the ratio of book value and operating costs of compressors to pipelines. The resulting residual attributed to compressors is divided by the quantity of horsepower to obtain the compressor user price. Similarly, the resulting residual attributed to pipelines is divided by the quantity of pipeline services to obtain the pipeline user price. All prices and quantities are scaled such that the geometric mean equals zero. A more detailed description of the data sources and the construction of the variables is contained in the Appendix.

The natural gas price and quantity data used in Section V are from various issues of Natural Gas Monthly. The price information for low sulphur residual fuel oil and btu content of

[18]See equation A8, page 320: $P = .382d^2L$ where P = pipeline capital services, d = weighted average diameter, and L = miles of transmission pipelines.

natural gas and fuel oil are from various issues of Monthly Energy Review. To estimate free-market natural gas prices, we assume they would reach parity, on a btu equivalent basis, with low sulphur residual fuel oil. We assume a constant btu content for natural gas of 1.028 million btu/mcf. Residual fuel oil contains 6.287 million btu/barrel. Thus, 6.1 mcf of gas contains the same btus as one barrel of residual fuel oil.

V. Estimation Results

The four equation system consists of the restricted cost function (3), one of the two variable share equations (5), and the two shadow share equations (6). The statistical model allows for some firm heterogeneity in production.[19] We append additive errors to the cost and share equations. We allow for nonsystematic firm-specific effects by positing a first-order vector autoregressive structure that varies by firm for the cost function. We allow for error correlation among the share equations and the cost equation for the same firm and time period. The system is estimated using iterative three-stage least squares.

[19] With firm specific effects included in the restricted cost equation the estimated long-run elasticity of scale was 22.83, an obviously implausible magnitude. Other analysis from the production side (Sickles and Streitwieser, 1989) yielded quite plausible results with the firm specific effects included. Our sample covers a period of substantial price inflation. The substantial trending in factor input prices means that there is often very little variation, for selected inputs and firms, in the logarithm of prices. This is turn means that the within, or dummy variables, estimator prevents important curvature properties of the cost function from being identified because the within transformation does not allow the coefficients of time invariant regressors to be identified. Our firm-specific AR(1) specification can thus be viewed as an empirical compromise between standard treatments for heterogeneity and no treatment at all.

Parameter estimates are reported in Table 1.

All but 47 (5.4 percent) of the 864 estimated variable factor and shadow shares are nonnegative for the sample, as required for monotonicity of the restricted cost function. Concavity conditions on the cost function are meet at the sample means and for 85.7 percent of the sample observations.[20]

The estimated variable cost elasticity is 5.4178 at the sample mean, indicating decreasing returns to scale.[21] The estimate of long run cost elasticity at the sample mean is .7691. This indicates the technology exhibits increasing returns of 1.3002.[22] Another way to view the scale economies is in terms of percentage, SE = $(1 - \partial \ln c/\partial \ln Y)100$. At the sample mean SE = 23.09 percent, indicating that a ten percent increase in output would result in a 7.69 percent increase in total costs, or a 23 percent cost savings. Our estimated returns to scale is

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[20]For the restricted cost function to be concave in factor prices the Hessian matrix, $H = [\partial^2 CV/\partial w_i \partial w_j]$ is negative semi-definite. Alternatively, we can examine the matrix of Allen-Uzawa partial elasticities, $A = [\sigma_{ij}]$, which also should be negative semi-definite. In addition, the Hessian matrix of quasi-fixed factors, $B = [\partial^2 CV/\partial X_h \partial X_k]$ is positive semi-definite.

[21]The variable cost elasticity is defined as: $\varepsilon_{cvy} = (\partial CV/\partial Y)(Y/CV) = \partial \ln CV/\partial \ln Y$. The long run cost elasticity is: $\varepsilon_{cy} = (1 - \Sigma \partial \ln CV/\partial \ln X_k)^{-1} \varepsilon_{cvy}$ where $\Sigma \partial \ln CV/\partial \ln X_k$ is the sum of the shadow shares of the fixed factors given by equation (6), or the ratio of fixed to variable costs. This result does not require that the envelope condition hold, but if it does, the long-run and short-run elasticities coincide (Nadiri, 1982). The elasticity of scale, ε_{yc}, is defined as the inverse of the cost elasticity.

[22]For long run increasing returns to scale, the restricted cost function may exhibit decreasing, constant, or increasing returns to scale (though still less than the long run returns to scale), depending on the relationship between the short-run marginal cost and average variable cost at the given level of output.

TABLE 1: Parameter Estimates

β_0	1.3934*	γ_{EH}	.3469
	(.6562)		(.1191)
α_Y	5.8422**	γ_{EP}	-.0896**
	(.6717)		(.0305)
α_L	.4365**	γ_{HP}	-.0379
	(.0089)		(.0237)
α_E	.5635**	γ_{YL}	-.1347**
	(.0089)		(.0219)
α_H	-1.2759**	γ_{YE}	.1347**
	(.05759)		(.0219)
α_P	-4.7682**	γ_{YH}	.7580**
	(.1935)		(.1082)
γ_{YY}	-2.1846**	γ_{YP}	1.0456**
	(.6782)		(.3947)
γ_{LL}	.0463*	γ_{YT}	-.0849
	(.0249)		(.0945)
γ_{EE}	.0463*	δ_T	6.7304**
	(.0249)		(.3407)
γ_{HH}	-.7375**	δ_{TT}	-1.1100**
	(.1045)		(.0693)
γ_{PP}	-.3832	$\emptyset DE_2$	-2.9753**
	(.4261)		(.7057)
γ_{LE}	-.0463	$\emptyset DE_3$	.9107
	(.0249)		(.9575)
γ_{LH}	-.3469		
	(.1191)		
γ_{LP}	.0896		
	(.0305)		

*Significant at the 5 percent level.
**Significant at the 1 percent level.

Standard errors are in parentheses. The subscripts Y, L, E, H, P, and T are assigned to the coefficients associated with output, labor, energy, compressors, pipelines, and time respectively.

below the engineering derived upper bound on returns to scale of 2.07 (Robinson, 1972) and the estimate of 1.9223 reported by Aivazian, et al. (1987). The estimates of long-run elasticities of scale for the individual firms range from 1.1409 to 1.5670, depending on firm output levels. We found no evidence that scale economies have changed appreciably over the nine sample years.

The rate of technical change, or change in productivity, is generally measured from the production function as $\partial \ln Y / \partial T$, which is equivalent to $-\partial \ln C / \partial T$ from the dual cost side.[23] Aivazian, et al. (1987) estimated the 1953-79 change in total factor productivity for the industry averaged 3.33 percent per year. Our analysis indicates this trend has reversed itself in the 1980s, averaging -2.23 percent per year at the sample mean. The change in total factor productivity by year is given in Table 2. Scale economies clearly are shown to be as important in explaining productive growth (decline) as techical change. The relative contribution of scale economies varies with changes in the growth in output and changes in the elasticity of cost (ε_{cy}).

The 1981-83 and 1984-85 declines in productivity reflect the sharp decline in demand for natural gas and the industry's

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[23] A discrete approximation to the continous measure is defined by: $T_c = \frac{1}{2}(\varepsilon_{cyt} + \varepsilon_{cyt-1})\dot{Y} - \Sigma\frac{1}{2}(S^*_{it} + S^*_{it-1})\dot{X}_i$ where $\dot{Y} = \ln(Y_t/Y_{t-1})$, $\dot{X}_i = \ln(X_{it}/X_{it-1})$ and S^*_i = input share in terms of total long run cost, with quasi-fixed input prices as shadow prices. In the case of constant returns to scale the formulas for long run technical change coincides with that from the variable cost function under the assumption of cost minimization. For non-constant returns to scale, the formula must be adjusted to: $TFP = T_c + (1 - \varepsilon_{cy})\dot{Y} - \Sigma(S_i - S^*_i)\dot{X}_i$; where S_i = input share in terms of total short run cost, with quasi-fixed input prices as market prices. If $Z = Z^*$ then $S = S^*$ and the last term in the equation drops out (Slade, 1986).

inability to adjust all inputs quickly. The decline in demand was precipitated by the rising price of natural gas under deregulation, fuel switching of traditional natural gas users to alternative, comparably priced fuels, and general conservation efforts. The cost burden of pipeline "take-or-pay" obligations also contributed to the dramatic productivity decline in 1984-85. Productivity would likely have declined in 1983-84 also, except for an increase in production associated with a colder than normal winter and an upturn in the economy.

TABLE 2: Average Annual Change in Output, Total Factor Productivity and Contibuting Factors

Period	$\dot{Y}$	$\dot{TFP}$	-T*	Scale Economies*
1977-78	2.789%	2.512%	64.542%	35.458%
1978-79	.410	4.422	60.945	39.055
1979-80	1.292	- .714	107.563	- 7.563
1980-81	3.202	.754	25.330	74.668
1981-82	- 7.904	- 8.932	75.140	24.860
1982-83	-12.634	-10.416	68.563	31.437
1983-84	3.985	1.178	48.718	51.282
1984-85	-12.339	- 9.567	73.137	26.863

*Percent of $\dot{TFP}$.

Firm specific changes in total factor productivity vary considerably, from -8.75 to 4.21. The two firms which experienced the greatest productivity declines are those that usually transport and sell large quantities of natural gas for other pipeline companies. In times of declining demand, purchases from other pipeline companies are usually the first to be cut. Five of the twenty-four firms appear to have been able to maintain positive productivity growth. In general, the more productive firms were those with a (relatively) large, and growing, portion of their throughput being transport for others. This lends support to the argument that changes in regulation to free up transport services without involving the pipeline as a gas merchant have been beneficial. However, increasing transport for others services alone has not been a guarantee of increased productivity.

Table 3 shows the short-run and long-run price elasticities of demand.[24] All the own price elasticities have the correct sign. Pipeline capital services exhibit the lowest elasticity with respect to a price change.

Energy and compressor servies are complements, reflecting the fact that increasing horsepower capacity requires proportionately more energy to operate. Labor and pipeline services are also complements, though to a much lessor degree. All other input pairs are substitutes. All the substitution elasticities are high, indicating a broad range of relative input combinations in production.

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[24]The variable price elasticities are derived by $n_i = M_i \sigma_{ii}$ and $n_{ij} = S_j \sigma_{ij}$, where S_j = expense share of input j, and σ_{ij} = Allen-Uzawa partial elasticities of substitution. The AES along the variable cost function are calculated by $\sigma_{ij} = (\gamma_{ij} + M_i M_j)/M_i M_j$ and $\sigma_{ii} = (\gamma_{ii} + M_i^2 - M_i)/M_i^2$; where M_i = restricted expense share of input i, γ_{ij} = parameter associated with the $\ln w_i \ln w_j$ term. The variable AES for the quasi-fixed inputs are zero. The long run AES are retrieved by $\sigma_{ij} = CC_{ij}/C_i C_j$; where C is the static equilibrium total cost, $C_i = \partial C/\partial w_i$, and $C_{ij} = \partial^2 C/\partial C_i \partial C_j$. Our calculation of the long run AES is based upon the methodology found in Brown and Christensen (1981).

TABLE 3: Estimates of Short-Run and Long-Run Price Elasticities*

Price Elasticities	Short Run Variable	Long Run
n_{LL}	-.4575	-1.3662
n_{EE}	-.3544	-1.0608
n_{HH}		-1.6060
n_{PP}		- .4521
n_{LE}	.4575	.3298
n_{LH}		1.6919
n_{LP}		- .5496
n_{EH}		- .7035
n_{EP}		1.3944
n_{HP}		1.2616

*Based on estimated share values and evalutated at sample mean.

We now turn our attention to the costs and benefits of the NGPA partial price decontrol relative to total field price decontrol. We also examine the impact on various categories of natural gas end-users.

VI. Effects of the NGPA Vs. Total Price Decontrol

The primary objective of the NGPA was to increase the exploration, production, and flow of natural gas through the interstate pipeline system to gas starved regions of the U.S. not served by intrastate pipelines. The legislature elected not to totally decontrol natural gas prices at the well-head in order to prevent producers of low cost gas from reaping windfall profits. The NGPA encouraged exploration and production of new, high cost natural gas through a complex system of immediate and gradual well-head price decontrol. It prevented average cost pricing through permanent price controls on all old, cheap natural gas.

The incremental price schedule was intended to steer the high cost gas to industrial users in order to protect residential users, who were supposed to receive the low cost gas. By allowing the pipeline companies to "roll-in" high gas costs, the transmission industry was encouraged to purchase high cost gas. Many firms rushed to sign long term contracts promising to "take-or-pay" $7 and $8/mcf gas in order to insure steady supplies for its customers. Despite all good intentions, the NGPA was greatly flawed in that it assumed the price of oil, the chief competitor to natural gas, would continually increase. The unexpected decline in oil prices which began in 1982[25] revealed the extent to which the NGPA distorted the competitive forces it hoped to nurture.

The NGPA clearly hurt the interstate natural gas pipeline industry in terms of increased production costs, decreased throughput and productivity declines. The dramatic increases in natural gas prices following enactment of the NGPA precipitated an increase in natural gas supplies from producers, but a decline in demand by consumers. This section examines who benefited and who was hurt during the first eight years under the partial price decontrol of the NGPA. We compare this to what might have happened under the alternative policy of total price decontrol.

It is not our intent to develop a full supply-demand model for natural gas in the U.S., or to estimate the price elasticity for natural gas by various categories of producers and consumers. Rather, we start with a base case of total well-head

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[25]U.S. crude oil price control was ended in 1981. This, coupled with the weaking of OPEC to control output and declining demand led to a steady drop in crude oil prices.

price decontrol in 1978 (when the NGPA became effective) with no change in the quantity of gas supplied by producers, purchased and transported by the pipelines, or consumed by various end users. We then examine the sensitivity of our results to different natural gas price levels (relative to oil), and to changes in the aggregate demand for natural gas.

For our base case, we assume natural gas well-head prices were totally decontroled in 1978 and that the average free market price of gas to end-users was at parity, on a btu equivalent basis, with its chief competing fuel, low sulphur residual fuel oil. We assume no change in the transport rate structure of the transmission industry. Initially, we assume also that there is no change in the quantity of natural gas supplied by producers, consumed and transported by the transmission industry, or demanded by end users.

Under the NGPA natural gas producers were encouraged to develop high cost gas while leaving known reserves of low cost gas in the ground. As a result the average well-head price of gas rose from $.79/mcf in 1977 to $2.51 in 1985. However, the price individual producers received varied greatly, depending on the NGPA classification of the well. As Table 4 shows, the estimated free market well-head price for natural gas would have exceeded the actual average well-head price for every year except 1983 and 1985. Assuming no change in the quantity sold, producers lost nearly $106.3 billion in revenues due to the implementation of partial price decontrol.

In contrast, consumers, as a whole, enjoyed a $98.7 billion subsidy for the natural gas they consumed. As Table 5 illustates, the free market price to consumers would have been higher than the actual price paid in every year except 1983 and 1985. However, the gains to consumers were not distributed evenly among types of consumers. The actual average prices and quantities of natural gas consumed, by type of consumer, are given in Table 6. Contrary to the intent of the NGPA, higher cost gas was largely directed to the inelastic residential market and away from the industrial and utility users. This occured because the price of fuel oil began to fall in 1981 and large industry and utilities had the potential to switch fuels (between natural gas and fuel oil) fairly easily. Pipeline companies steered lower cost gas to these customers in an effort to preserve these markets. The NGPA allowed price discrimination by consumer type, resulted in residential users paying nearly $8.6 billion more for gas than they would have under total price decontrol, while utilities, commercial, industrial users paid less, by $41.3, $3.0, and $69.9 billion respectively.

As natural gas is an input in the production process of the transmission industry,[26] an increase (decrease) in natural gas well-head prices would be reflected by an increase (decrease) in variable costs. Had total price decontrol been adopted, instead of partial price decontrol, the twenty-four firms in our sample would have paid $1.4 billion more for energy than they actually did. As Table 7 shows, the firms' costs would have increased from

[26] Here we consider only the natural gas used as energy in the production process and exclude gas purchased for transport and resale to customers.

1978-82, but decreased in the three following years, as they could have avoided the high cost gas purchases they incurred under the NGPA. The increase in costs for this eight year period would have resulted in a further decline in productivity, from an annual average of -2.23 to -2.55.

Throughout the 1980's the supply of natural gas exceeded demand. Much of the reserve supply was of low cost gas which would have been marketed in the absence of the NGPA. The free market price for natural gas might not have reached parity with residual fuel oil during this time.[27] For every 5 percent below full price parity with fuel oil (assuming no change in demand), natural gas producers' lost revenues decline by $31.5 billion and consumers' gain, as a whole, is reduced by $23.9 billion. However, residential consumers' overpayments (i.e what they paid under the NGPA and what they would have paid with decontroled prices at 95 percent parity with fuel oil), increase by $8.1 billion. Industry and utility gains decline by $12.7 and $5.8 billion respectively. With a 5 percent price reduction, commercial users lose all gains and actualy suffer a $4.3 billion overpayment. Productivity in the interstate transmission industry would have declined on average by 2.57 per year; the firm losses would decrease by $.4 billion.

The calculated free-market price of natural gas (at 100 percent parity with residual fuel oil) is higher than the end user

[27]Unregulated natural gas prices would achieve parity with (on a btu basis) with its greatest competitor, residual fuel oil once the gas bubble dissipated. This probably would have occurred sometime after 1985.

average price of natural gas under the NGPA for all years except 1984. It is likely that natural gas demand would have been lower during the period of this analysis had prices been totally decontrolled. For every 5 percent decline in aggregate demand, consumer benefits from full price decontrol would be reduced by \$4.9 billion.[28] Producers would gain \$101.0 billion in revenue that was lost under the NGPA. The interstate transmission industry would have suffered a 3.21 average annual decline in productivity, and firm benefits would fall by \$.4 billion.

The above analysis assumed there would be no change in the FERC authorized rate of return and transport rate structure for the interstate transmission industry. Any increase (decrease) in the rate of return would be reflected in the transport rate structure, and would be reflected in higher (lower) average prices to consumers. However, an analysis of how the rate structure would change, for a given change in the rate of return, and a determinization of the relative losses (benefits) by class of end user is beyond the scope of this paper.

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[28]Given full price decontrol, and free market prices at (BTU) parity with residual fuel oil, consumers paid \$98.7 billion less for their natural gas than under the NGPA. If free market prices only reached 95 percent parity with fuel oil, consumer expenditures would have been \$93.8 billion less than under the NGPA, a difference of \$4.9 billion from full parity benefits.

TABLE 4: Producer Prices and Revenues

	Quantity Sold BCF	Actual Well-Head $/MCF	Estimated Free-Market $/MCF	Lost Revenue $ Billion
1978	18,969	$ .91	$ 1.09	$ 3,391
1979	19,553	1.18	2.06	17,160
1980	19,407	1.56	3.29	33,502
1981	19,181	1.98	4.17	41,913
1982	17,758	2.46	3.27	14,379
1983	16,033	2.59	2.54	- 803
1984	17,392	2.66	2.76	1,647
1985	16,382	2.51	2.21	- 4,908
			Total	$106,280

TABLE 5: Consumer Prices and Expenditures

	Quantity Purchased BCF	Actual $/MCF	Estimated Free-Market $/MCF	Expenditure Savings $ Billion
1978	17,449	$1.98	$2.16	$ 3,120
1979	18,141	2.34	3.22	15,921
1980	18,216	2.91	4.64	31,446
1981	17,834	3.51	5.70	38,969
1982	16,295	4.32	5.13	13,194
1983	15,367	4.82	4.77	- 770
1984	16,345	4.85	4.95	1,548
1985	15,811	4.72	4.42	- 4,737
			Total	$ 98,692

TABLE 6: Prices, Quantities, and Expenditure Savings By Type of Consumer

Residential Consumers

	Quantity Purchased BCF	Actual $/MCF	Estimated Free-Market $/MCF	Expenditure Savings $ Billion
1978	4,903	$2.56	$ 2.16	-$ 1,967
1979	4,965	2.98	3.22	1,180
1980	4,752	3.68	4.67	4,544
1981	4,546	4.29	5.70	6,388
1982	4,633	5.17	5.13	- 186
1983	4,381	6.06	4.77	- 5,652
1984	4,555	6.12	4.95	- 5,354
1985	4,433	6.12	4.42	- 7,534
			Total	-$ 8,582

TABLE 6 (continued)

Commercial

	Quantity Purchased BCF	Actual $/MCF	Estimated Free-Market $/MCF	Expenditure Savings $ Billion
1978	2,310	$2.23	$2.16	-$ 164
1979	2,485	2.73	3.22	1,211
1980	2,441	3.39	4.64	3,042
1981	2,502	4.00	5.70	4,241
1982	2,606	4.82	5.13	807
1983	2,433	5.59	4.77	- 1,995
1984	2,524	5.55	4.95	- 1,527
1985	2,432	5.50	4.42	- 2,626
			Total	$ 2,989

Utilities

	Quantity Purchased BCF	Actual $/MCF	Estimated Free-Market $/MCF	Expenditure Savings $ Billion
1978	3,188	$1.48	$ 2.16	$ 2,164
1979	3,491	1.80	3.22	4,914
1980	3,682	2.27	4.67	8,713
1981	3,640	2.89	5.70	10,211
1982	3,226	3.48	5.13	5,322
1983	2,911	3.58	4.77	3,464
1984	3,111	3.70	4.95	3,872
1985	3,044	3.55	4.42	2,650
			Total	$ 41,309

Industry

	Quantity Purchased BCF	Actual $/MCF	Estimated Free-Market $/MCF	Expenditure Savings $ Billion
1978	6,757	$1.70	$2.16	$ 3,100
1979	6,899	1.99	3.22	8,469
1980	7,172	2.56	4.64	14,891
1981	7,128	3.14	5.70	18,213
1982	5,831	3.87	5.13	7,345
1983	5,643	4.18	4.77	3,329
1984	6,154	4.22	4.95	4,460
1985	5,901	3.95	4.42	2,776
			Total	$ 69,929

TABLE 7: Variable Cost and Productivity

	Var. Cost Increase** $ Million	TFP* With Free-Market Prices	Decline in TFP*
1978	$ 33.5	2.43	- .24
1979	326.3	4.15	- .27
1980	628.5	- .59	.12
1981	788.6	.75	0
1982	1.5	- 8.28	- .65
1983	-144.8	-10.45	- .03
1984	- 68.2	1.24	.06
1985	-205.6	- 9.65	- .08
Total	$1,359.8		

*For the average interstate pipeline company in our sample.
**Variable cost includes natural gas used as energy in production, but excluded gas purchased, transported and delivered to customers. Value is the total for the 24 firms in our sample, not the entire interstate transmission industry.

VII. Conclusions

The purpose of this paper has been to examine the production technology and cost structure of the interstate natural gas pipeline industry under NGPA partial price deregulation. We have employed a restricted (variable) cost function to estimate scale elasticities, substitution possibilities, and technical and productive change within a static equilibrium framework. In general, the parameter estimates and summary statistics are as expected. Empirical results indicate substantial long-run economies of scale in the natural gas pipeline industry as well as considerable long-run substitution among most inputs.

During the first eight years of deregulation, there has been a significant decline in productivity, paralleling the decline in output for the industry. If the goal of public policy were to improve productivity in the industry, such policy should be designed to promote the demand for natural gas and the free flow of gas between markets. Current regulatory efforts to promote voluntary non-contract transmission appears to have enabled some firms to mitigate the overall industry productivity decline. It should be noted that, in general, any increase in natural gas consumption is likely to occur at the expense of other energy sources, primarily oil-based products. However, a short-term increase in natural gas consumption (and productivity in the transmission industry) is not likely to be accompanied by a corresponding decline in production and productivity in the domestic oil industry, as foreign oil producers are the marginal suppliers.[29]

The NGPA established a complex schedule of partial and gradual decontrol of natural gas prices at the well-head. The legislation cost natural gas producers $106 billion in lost revenues by holding the average well-head price below the unregulated, free market level. The interstate transmission industry and their customers benefited by paying less for their natural gas than they otherwise would have, by $1.4 and $98.7 billion respectively. However, the benefits to consumers were very unevenly distributed. For the 1978-85 period, utilities, commercial, and industrial users paid (on average) less for their gas than they would have under total decontrol, while residential users paid $8.6 billion more. The NGPA, and FERC oversight practices, have allowed the transmission industry to price discriminate among

[29]Foriegn oil producers are the marginal suppliers unless the world price of oil falls below the cost of production for U.S. domestic oil producers.

customers, according to their demand elasticity. In the future, as more high cost gas is placed on the market, consumer prices will likely rise also. Should oil prices remain below that of the early 1980's, it will become increasingly difficult for the transmission industry to supply industry and utilities with natural gas as prices below (BTU) parity with residual fuel oil. Natural gas demand and pipeline throughput and productivity are likely to continue to decline.

APPENDIX

The measurement of the output and input variables are similar to those employed by Aivazian, et al. (1987) in order to allow for comparisons between their study of the natural gas transmission industry during its years of expansion prior to the NGPA and our study of a mature industry coping with shrinking markets and a different regulatory environment. All data are from the 1977-85 FERC Form-2: Annual Report of Major Natural Gas Pipeline Company or the Annual Statistics of Interstate Natural Gas Pipeline Companies (ASI) unless otherwise indicated. The Form-2 is filed annually with FERC by each major interstate natural gas pipeline company. A Form-2 (from which data are extracted to make up the ASI publication) contains detailed information on the financial and operating expenses of the firm and a breakdown of types of output and revenues earned. A firm's Form-2 can run anywhere from 200 pages to over 1000. These reports are not generally published and distributed, but can be ordered through FERC.

Total cubic feet-miles of output is the total volume of gas delivered under "sales for resale", "mainline sales", and "transport of gas of others". These quantities, in bcf, are multiplied by the miles transported. Gas quantities are extracted from the "Gas Accounts-Deliveries" schedule. Miles transported are not reported for resale and mainline sales. The average length of the major transmission trunklines from the main production area(s) to the major delivery point(s) is used as the miles transported for these two categories. The mileage figures are calculated with the use of firm specific pipeline system maps. The weighted average miles transported for gas transported for others is calculated from the "Revenue from Transportation of Gas of Others" schedule.

The quantity of labor is calculated by multiplying the proportion of transmission labor expenses relative to total labor expenses, from the "Distribution of Wages and Salaries" schedule, by total number of firm employees. The expense for energy used in transmission is from the Transmission Expense section of the "Operations and Maintenance Expense" schedule. The quantity of energy consumed in production is measured in thousand cubic feet (mcf) of natural gas used by the firm, as reported in the "Gas Used by Utility" schedule.

Two measures of capital input are used: total horsepower ratings of transmission compressor stations as a proxy for compressor capital services and tons of steel as a proxy for pipeline services. In measuring the quantity of compressor and pipeline capital services used in production, we had to draw on an additional data source as neither the horsepower rating nor pipeline diameters are reported directly in the Form-2 "Compressor Station" and "Transmission Lines" schedules after 1979. To determine total horsepower and pipeline diameter after 1979 we relied on the "Pipeline Economics Report" published in the Oil and Gas Journal and supplemental information in the FORM-2. The OGJ "Pipeline Economics Report" is published once a year (usually in November) and contains data on the configuration and cost of current pipeline and compressor station construction. Data are given by state and for specific projects. By comparing the location of the individual projects in the OGJ with the areas of operation for each firm and the information from Section 5 of the Form-2 "Important Changes During the Year" statement, we are usually able to determine which company is undertaking the project and to update the 1979 figures year by year. Since the firms have not significantly expanded their pipeline systems during the period of study, the method of calculating horsepower and pipeline diameter is not as cumbersome as might be expected.

As mentioned in the text, the price of labor and energy are derived by dividing total labor and energy expenses by their respective quantities. Unfortunately, such is not possible regarding capital services; instead, a value added basis is used. First, total revenues from sales for resale, mainline sales, and transport of gas of others are obtained from the "Gas Operating Revenues" schedule. The cost of labor, energy, and gas purchased are netted out. This net revenue was allocated between compressor and pipeline services based on the ratio of book value cost and operating costs of compressors to pipelines (referred to as "mains"). The end of year book value costs are from the Transmission Plant section of the "Gas Plant in Service" schedule. The operating costs are from the Transmission Expenses section of the "Gas Operation and Maintenance Expenses" schedule. The resulting two residuals are divided by the appropriate quantity, horsepower or pipeline steel tons, to obtain user prices for the two capital categories.

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