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

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Abstract

The structure of production in the natural gas transmission industry is estimated using the dual restricted cost function based on panel data for twenty four firms. A standard translog variable cost function with firm fixed effects is augmented with controls for capacity utilization, technical change, and shifting regulatory regimes. During the implementation of the Natural Gas Policy Act (NGPA), 1978-1985, the industry exhibited no significant increase in productivity, largely attributable to the decline in output for the industry. Regulatory efforts to promote voluntary non-contract transmission appear to have enabled some firms to mitigate the overall industry productivity stagnation. The NGPA instituted a complex schedule of partial and gradual decontrol of natural gas prices at the well head. This form of deregulation costs natural gas producers over $100 billion in lost revenues, relative to immediate and full price deregulation. However, the transmission firms benefitted by paying $1.5 billion less for natural gas than they would have under total deregulation. The benefits to consumers, totaling $98.7 billion, were unevenly distributed. On average, for the 1978-1985 period, utilities, commercial, and industrial users paid less for their gas than they would have under total decontrol and residential users paid $8.6 billion more. The NGPA and Federal Regulatory Commission oversight practices allow the transmission industry to price discriminate among customers.

Keywords: productivity, cost structure, natural gas transmission industry

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I. Introduction

The 1978 Natural Gas Policy Act (NGPA)[1] instituted partial and gradual decontrol of natural gas well head prices. The impact of the NGPA was not limited to the field market. Significant effects were felt downstream in the transmission and distribution industries as the pressures of rising average price and falling demand in the early 1980s placed considerable stress on the institutions and traditional transactional arrangements of the natural gas transmission industry.

Deregulation of other transportation industries (airline and trucking) 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 in the transmission industry remains to be determined. Consumer groups and Congressional opponents of the NGPA argued that it would result in higher inflation, higher unemployment, increase the political power and profits of the major oil and gas firms, and worsen the balance of trade.[3] In addition, concern that the pattern of mergers would diminish competition and hurt consumers prompted the Justice Department's Antitrust Division and the Federal Trade Commission officials to initiate several investigations to determine if transmission firms were shipping the lowest cost gas possible.[4] Those in the industry, however, contend that mergers and takeovers have occurred because acquired firms were poorly managed and inefficient. Increased suppliers, customers, operating flexibility, and efficiency have been cited as the motivation behind the mergers and takeovers.[5]

The purpose of this paper is to provide the first comprehensive firm level analysis of cost structures and production in the interstate pipeline industry during the transition period from price regulation to partial deregulation, 1977-1985. Our study is based on a newly constructed panel of twenty-four interstate pipeline firms. Particular attention is focused on the rigidities in the production process due to the presence of quasi-fixed capital inputs. We examine the impact of output change, technical change, scale economies, and non-optimal input allocation on total factor productivity (TFP) during the years 1977-1985 and the implications of NGPA partial price decontrol relative to total well head price decontrol for residential, commercial, utility, and industrial consumers of natural gas as well as the transport industry itself.

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 versus total price decontrol scenarios based on our estimates are contained in Sections V and VI respectively. Concluding remarks are in Section VII. A more detailed description 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 transmission industry traditionally served as both merchant and shipper. It is linked upstream to producers with long term contracts to purchase natural gas and linked downstream to local distribution companies with similar long term supply contracts. The transmission industry's structure has been greatly influenced by the requirements of the technology. 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 developed. The U.S. Constitution prohibits State and local authorities from regulating or interfering with interstate trade, thus Federal regulation was sought to curb monopoly behavior in interstate transmission. Congress passed the Natural Gas Act of 1938 (NGA) and simultaneously created the Federal Power Commission (FPC). The Federal Energy Regulatory Commission (FERC), which succeeded the FPC, is empowered to certify the construction, modification, and abandonment of interstate pipeline facilities, and to review interstate pipelines' operating and maintenance costs in order to establish rate schedules for all services 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 remains with State authorities. Federal price regulation was later extended to the well head in order to insure equitable prices in all regions of the country.[6] 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 six years, 1971-1976. The 1973 oil price shock had a direct impact on the demand for natural gas and its transport. To the extent possible, energy consumers switched 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 quickly 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.[7] 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 subsequent increase in natural gas prices--a 218% increase by 1985--dealt the natural gas transmission industry a dual blow. First, the demand for natural gas transport services declined, mirroring the decline in demand for natural gas itself. Second, the cost of transporting a unit of natural gas increased as natural gas is the primary fuel for pipeline compressors.

The NGPA instituted gradual and partial price decontrol of natural gas sold by producers to interstate markets. The 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. 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% of flowing gas was free of well head price regulation.

The interstate pipelines remain under rate of return regulation. There have been 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 early effects of the partial decontrol on the structure of production and productivity of the transmission industry. We can then compare what happened under the NGPA with the scenario in which well head prices were totally decontrolled.

III. The Model

We estimate the structure of production in the natural gas transmission industry using the dual restricted (variable) cost function. The motivation for estimating the variable rather than the total cost function is that we wish to allow for the existence of temporary disequilibrium 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 contractual arrangements within the industry, particularly the long term contracts between producers and pipelines, 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. Berndt and Fuss (1986), Morrison (1986), and Slade (1986) explored the implication of temporary equilibrium for productivity growth analysis. 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 suggest that there has been a marked decline in productivity during the 1980s (Sickles and Streitwieser, 1988). This decline may be over-estimated as their production function based analysis assumed that producers are in short run and long run equilibrium. In fact, the transmission industry may have been in temporary disequilibrium due to the short run fixity of capital inputs.[8] Our analysis assumes that the industry minimizes variable costs due to market forces, and not necessarily FERC regulation.[9] All factor markets are assumed to be competitively determined. Output is assumed to meet demand since FERC establishes the transport rate schedules on a firm-by-firm basis and requires each firm to satisfy the corresponding demand.

A translog restricted cost function is used to model the short run equilibrium. Dummy variables (R_d) are used to represent three different regulatory epochs: one for the years before the NGPA went into effect (1977-1978), a second for the years after the NGPA was passed, but before the natural gas spot market and open access programs developed (1979-1983), and a third dummy for the years when the open access programs and the spot market were operating (after 1983).[10] Capacity utilization (CU) is included in the model to capture subequilibrium variations in the utilization of the fixed factors (Cowing, Small, and Stevensen, 1981). The assumption of full utilization of all inputs over time may be appropriate for long run analysis with fully flexible inputs, but such an assumption is unwarranted in the case of quasi-fixed factors. Since the transmission firms are capital intensive, differences in capital utilization rates can have substantial impact on the optimal capital levels.

Given exogeneity of output and input prices the short run cost minimizing problem for the firm operating at full capacity is to solve

$$\min \Sigma W_i X_i \qquad \text{subject to } H(Y,X;T) = 0, \qquad (1)$$

where H is the transformation function of the production technology. The solution to (1) is the short run variable cost function given by:

$$CV = G(Y,W,X;T). \qquad (2)$$

Here Y is the output,[11] 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[12], and X_3 and X_4 represent the quantity of quasi-fixed capital inputs, measured by compressor horsepower and tons of pipelines respectively. G is homogeneous of degree one, non-decreasing, and concave in the factor prices W, nonincreasing and convex in the levels of quasi-fixed factors X, and nonnegative and nondecreasing in output Y.

We approximate G with a standard translog function (Christensen, et al. 1973) that is augmented with controls for capacity utilization, technical change, and shifting regulatory regimes. Capacity utilization is measured by the ratio of actual to maximum possible capital usage. Adjustment for capacity utilization rates is important for three reasons. First, transmission firms are highly capital intensive and relatively minor changes in capacity utilization rates reflect substantial changes in optimal capital inputs. Second, with high capital intensity an adjustment for capacity utilization is necessary to minimize the potential of distortion due to capital measurement error. Finally, to the extent that technical change in embodied in capital the variation in quality or efficiency should be accounted for.

Our treatment of capacity utilization adjustments and of temporal patterns in productivity change is in part driven by empirical concerns. A fully interactive parameterzation imposes too much informational requirements on our firm level data, especially when we control for within variation using the dummy variables fixed effect models. Our empirical compromise allows for a fairly flexible pattern of neutral technical change and controls for capacity utilization in two ways. The first is by allowing for first-order capacity utilization effects in the cost function. The second approach scales the two capital inputs by capital utilization to obtain a measure of utilized capital. Thus, in the second treatment, the disequilibrium effect on TFP growth is by construction zero (Table 4). Our estimating equations are given in (3) and (4) below, where the second treatment of capacity utilization sets $8=0$ and scales the X_is by CU:

$$\ln CV = \alpha_0 + \alpha_y \ln Y + \tfrac{1}{2}\beta_{yy}(\ln Y)^2 + \sum_{i=1}^{2}\alpha_i \ln W_i + \sum_{k=1}^{2}\alpha_k \ln X_k + \tfrac{1}{2}\sum_{i=1}^{2}\sum_{j=1}^{2}\beta_{ij}\ln W_i \ln W_j +$$
$$\tfrac{1}{2}\sum_{k=1}^{2}\sum_{h=1}^{2}\beta_{hk}\ln X_h \ln X_k + \sum_{i=1}^{2}\sum_{k=1}^{2}\beta_{ik}\ln W_i \ln X_k + \sum_{i=1}^{2}\beta_{iy}\ln Y \ln W_i + \sum_{k=1}^{2}\beta_{ky}\ln Y \ln X_k + \tag{3}$$
$$\gamma_t T + \tfrac{1}{2}\gamma_{tt}T^2 + \gamma_{ty}T\ln Y + \lambda \ln CU + \sum_{m=2}^{3}\phi_d R_d .$$

Conditions for linear homogeneity and symmetry are imposed while monotonicity and concavity conditions 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:

$$M_i = \alpha_i + \sum_{i=1}^{2}\beta_{ij}\ln W_j + \beta_{yi}\ln Y + \sum_{k=1}^{2}\beta_{ik}\ln X_k \qquad i = 1, 2 , \tag{4}$$

where M_i is the variable cost share for variable input X_i.

For purposes of estimation, Morrison (1985), among others, suggests adding the "shadow share" equation, $-\partial \ln G/\partial \ln X_k = Z_k X_k/CV$, 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. If the market price, W_k, is less than the shadow price, Z_k, the firm desires more of the fixed factor than is available in the short run. Berndt and Hesse (1986) posit the theoretical basis for their inclusion in the model: Z_k is "...the best firms can do for their shareholders in the short run given exogenous input prices, output demand Y, and the fixed capital stock K. Since this shadow value equation incorporates the effects of economic optimization, it is included in the system of estimating equations."[13] For the restricted translog cost function these take the form:

$$M_k = -[\ \alpha_k + \sum_{i=1}^{2}\beta_{ik}\ln W_i + \beta_{yk}\ln Y + \sum_{h=1}^{2}\beta_{hk}\ln X_{hk}\ ] \qquad k = 1, 2 . \tag{5}$$

Regularity conditions require these shadow share equations to be positive.

Although we are estimating the restricted cost function, our objective is to describe the long run production process. As noted by Caves, Christensen, and Swanson (1981), various characteristics of long run production can be derived from the restricted cost function. Write the short run total cost function 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 $X_k^* = g(W,Y,Z^*)$. The long run cost function is thus

$C = H(w,Y,Z^*)$.

IV. The Data

The technology of the natural gas pipeline industry is very basic: natural gas is compressed and transported from producing to consuming regions via long distance pipelines.[14] 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 interstate natural gas pipeline companies for nine years, 1977-1985.[15] These firms are listed in Table 1. Table 2 provides a brief listing of mergers and acquisitions affecting these companies during the sample period.

Total output is the amount of gas delivered (bcf) to local distribution companies, industrial customers, and gas transported for others measured in billion cubic feet-miles. The quantity of labor is based on head counts. The quantity of energy consumed in production is measured by the thousand cubic feet (mcf) of natural gas used by the firm in transmission. Two measures of capital are used, as suggested by Aivazian, et al. (1987). Total horsepower rating of all compressors in place on the transmission lines represents compressor station services. Pipeline capital services are measured in terms of the tons of steel transmission line pipes.[16]

Labor and energy prices are based on expenditure data. Prices for capital are Christensen-Jorgenson (1969) service prices. The ex post rate of return for capital services is derived on the value added basis. Capacity utilization rates, or load factors, are calculated as the ratio of average daily deliveries to peak day deliveries. A more detailed description of the data sources and the construction of the variables is contained in the Appendix.

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). We append additive errors to the cost and share equations and estimate the system by iterative seemingly unrelated regressions. Table 3 provides three sets of parameter estimates. Model I and II's estimates are based on the first treatment of capacity utilization. In model I we allow for nonsystematic firm specific effects in the cost function by positing a first-order autoregressive structure that varies by firm. Model II augments this with cost function fixed firm effects. Model III utilizes the general treatment for nonsystematic and systematic unobserved heterogeneity in model II but controls for the effect of secular declines in natural gas demand on utilized pipeline and pumping station capacity by replacing observed capital with utilized capital.

All of the 864 estimated variable factor and shadow shares are nonnegative with each model, as required for monotonicity of the restricted cost function. Examination of the concavity conditions on the restricted cost function are met at the sample mean and for all sample observations with each model.[17]

Parameter estimates and standard errors are given in Table 3. Firm Effects in model II are all significantly different from zero at the 99% level except for firms 1 and 16. We are able to reject the hypothesis that all firm effects jointly equal zero at the 99% level. Our discussion of empirical findings thus will be in terms of models II and III which differ only in the treatment of capacity utilization.

Results from Model II indicate a negative and significant effect of capacity utilization on variable costs. On average, utilization rates declined by 1.74% per year. The dummy variables for the two regulatory epochs after the NGPA went into effect are both negative; the post-1983 variable is significant only at the 10% level. This reflects the competitive forces pushing firms to minimize costs, particularly after the spot market developed.

Model II estimates indicate that the technology exhibits increasing long run returns of 1.58 at the sample means with a standard error of 0.31, which is not significantly different from unity at the 5% level.[18] Comparable scale results from model II are point estimates of 0.85 with a standard error 0.12, again not significantly different from unity at the 5% level. For all models firm specific estimates of long run elasticities of scale are inversely correlated with firm output. Other point estimates of returns to scale in the natural gas transmission industry range from 1.17 (Callen, 1978) to 2.07 (Robinson, 1972).

Yearly industry TFP growth rates and its components are reported in Table 4 for all three models. Aivazian, et al. (1987) estimated the industry 1953-1979 change in TFP growth averaged 3.33% per year. Our analysis indicates this trend has reversed itself in the 1980s, averaging -1.86% per year for model II and -0.57% per year for model III.[19] Estimated TFP growth rates evaluated at sample means of the variables are somewhat lower, -1.49 per year for model II and -0.44 per year for model III. Corresponding to these point estimates are standard errors of 0.15 and 0.33, indicating significantly negative productivity growth for model II and productivity growth that is insignificantly different from zero (at conventional levels) for model III. There appears to be no significant progress or regress; therefore, when utilization rates are used to scale capital inputs into effective units, while separable additive treatment in model II results in estimates of significant regress.

Model II indicates technical change accounts for slightly over one-half of the productivity decline and scale economies account for nearly 40%. Disequilibrium due to fixed capital inputs accounts for the remaining 7%. It should be noted that the change in output drives both the technical change and scale economy components of TFP growth (TFP). When we adjust for capacity utilization in model III, technical change accounts for 91% of TFP and scale economies accounts for only 9%.

The decline in TFP (although insignificantly different from zero for model III) during the sample period is the result of the fall in output of 10% in three years: 1981-1982, 1982-1983, and 1984-1985 and reflects the industry's inability to adjust all inputs quickly. Declining 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 decline in TFP in 1984-1985. Productivity would likely have declined in 1983-1984 also, were it not for an increase in throughput due to a colder than normal winter and an upturn in the economy. Had output remained stable during those three years the average weighted annual TFP would have been 2.43% with model II and 3.98% with model III.

Firm specific average annual changes in TFP vary from -8.64% to 5.49% with model I. Models II and III yield very similar ranges. The two firms experiencing the greatest 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. Four firms appear to have been able to maintain positive TFP 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 factor productivity.

Table 5 provides short and long run Morishima substitution demand elasticities for each model. Estimated optimal levels of capital services are used to obtain the long run equilibrium elasticities derived with models I and II.[20] Optimal levels of the fixed capital factors at the mean are 84.7% of the observed levels. Optimal capital levels vary with output, from 91.2% in 1979 to 76.7% of observed levels in 1983. All the long run own price elasticities have the correct negative sign. The demand elasticity for labor and pipelines is near unity (model II), while the demand elasticity for energy is less elastic and for compressors is quite elastic.

Energy and compressor services are complements, reflecting the fact that increasing horsepower capacity requires proportionately more energy to operate. Labor is a complementary input with respect to energy and linepipe services. All other input pairs are substitutes. The cross demand elasticities are relatively high, except for that between labor and energy, indicating a broad range of relative input combinations in production. All input pairs are Morishima substitutes except energy to compressors and pipelines to labor in model I.[21] Elasticities across the models vary somewhat. Those derived from the model III are generally more elastic.

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 Versus 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. Congress 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 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 revealed the extent to which the NGPA distorted the competitive forces it hoped to nurture.[22]

This section examines who benefitted and who was hurt during the first eight years under the partial price decontrol of the NGPA. We do this by comparing the actual revenue/expenses of producers, transporters, and consumers with a scenario of total price decontrol. 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.

We begin with a base case of total well head 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.

Our base case also assumes that the average free market price of gas to endusers was at parity, on a Btu equivalent basis, with its chief competing fuel, low sulphur residual fuel oil. We assume no change in the industry transport rate structure. 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. Table 6 shows that 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 7 illustrates, 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 8. 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 occurred because the price of fuel oil began to fall in 1981 and manufacturing plants and electric 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 those markets. The NGPA allowed price discrimination by consumer type and 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.

Since natural gas is an input in the production process of the transmission industry, a change in natural gas well head prices affects production costs.[23] We recalculate the cost of transmission and factor expense shares based on the free market price of natural gas and our estimated variable cost function. Had total price decontrol been adopted, instead of partial price decontrol, the twenty-four firms in our sample would have paid $1.5 billion more for energy than they actually did. As Table 9 shows, the firms' costs would have increased from 1978-1982, but decreased in the three following years, as they could have avoided the high cost gas purchases they incurred under the NGPA. The net effect of the increase in energy costs for this eight year period would be a further decline in productivity growth, from an annual average of -1.86% per year to -1.96% per year with model II. Model III results in a similar effect, reducing productivity growth from -0.57% per year to -0.76 per year.

Throughout the 1980s 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.[24] For every five 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 decontrolled prices at 95% parity with fuel oil), increase by $8.1 billion. Industry and utility gains decline by $12.7 and $5.8 billion, respectively. With a five percent price reduction, commercial users lose all gains and actually suffer a $4.3 billion overpayment. Firms' losses over the eight year period would decrease by $0.4 billion although declines in productivity growth remain unchanged (relative to the base case).

The calculated free market price of natural gas (at 100% parity with residual fuel oil) is higher than the end user 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 five percent decline in aggregate demand, consumer benefits from full price decontrol would be reduced by $4.9 billion.[25] Producers would gain $101.0 billion in revenue that was lost under the NGPA. Firms' losses would decrease by $0.4 billion and changes in productivity growth are unchanged (relative to the base case).

The above analysis assumed there would be no change in FERC authorized rates of return and transport rate structures 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.

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 partial static equilibrium framework. In general, the parameter estimates and summary statistics are in keeping with previous studies of this industry.

During the first eight years of deregulation, there was no significant increase in productivity, largely attributable to 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 stagnation. 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. Any increase in natural gas consumption (and productivity in the transmission industry) is likely to be accompanied by a corresponding decline in production and productivity in the domestic oil industry, as domestic producers are the marginal suppliers.[26]

The NGPA established a complex schedule of partial and gradual decontrol of natural gas prices at the well head. During the sample period 1977-1985, 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 benefitted by paying less for their natural gas than they otherwise would have, by $1.5 and $98.7 billion, respectively. However, the benefits to consumers were very unevenly distributed. For the 1978-1985 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 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 continue to remain below those of the early 1980s, 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. Under such circumstances we would expect to see a degree of consolidation and structural reorganization in the industry, through mergers, takeovers, and possibly bankruptcies.[27] There were over a dozen mergers and acquisitions involving major interstate transmission firms in the past decade, as listed in Table 2. Although the acquired firm has often been financially stressed, only one firm, Columbia Gas Transmission, has been on the verge of bankruptcy. In 1991, it requested FERC to release it from high cost gas purchase contracts in order to avoid seeking Chapter 7 protection from bankruptcy.

FIGURE 1: DISTRIBUTION OF AVERAGE
ANNUAL GROWTH IN TFP

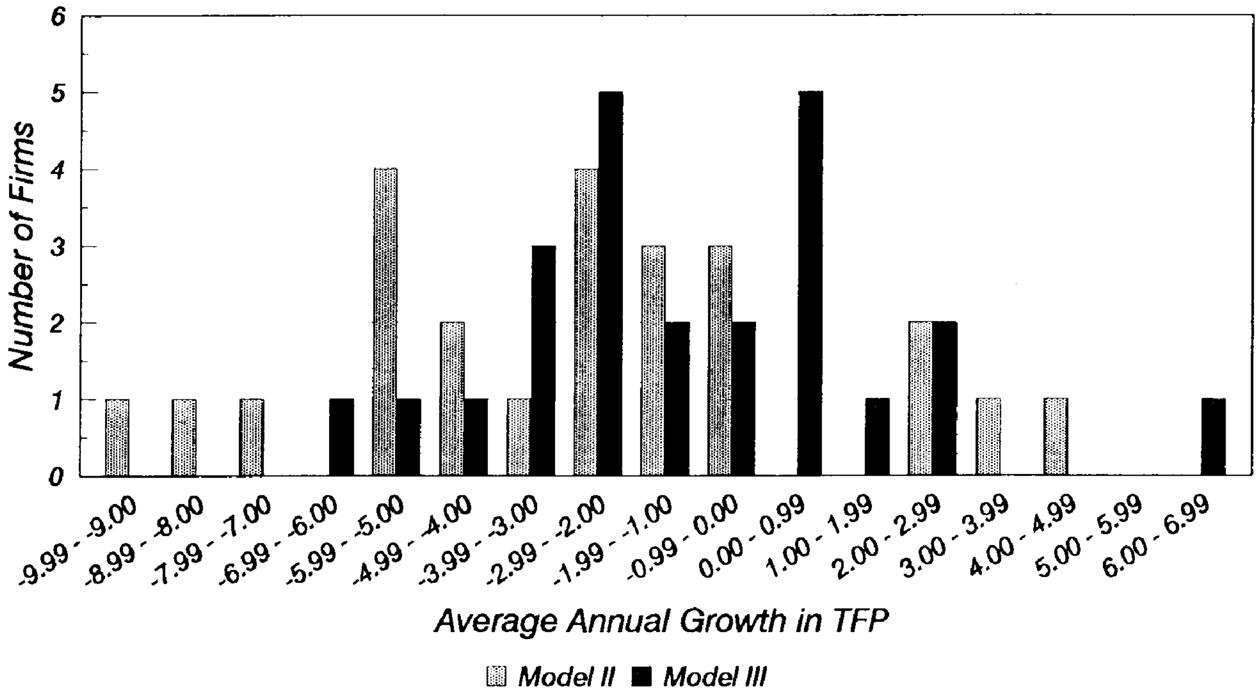

TABLE 1

Firms Included In Analysis

1. Algonquin Gas Transmission Company
2. American Natural Resources Company (formerly Michigan Wisconsin Pipe Line)
3. Arkansas-Louisiana Gas Company
4. Colorado Interstate Gas Company
5. Columbia Gas Transmission Corporation
6. Columbia Gulf Transmission Corporation
7. Consolidated Natural Gas Company
8. El Paso Natural Gas Company
9. Florida Gas Transmission Company
10. Mississippi River Transport
11. Natural Gas Pipeline Company of America
12. Northern Natural Gas Company (now InterNorth, Inc.)
13. Northwest Central Gas Company (formerly City Services Gas Company)
14. Northwest Pipeline Corporation
15. Panhandle Eastern Pipe Line Company
16. Sea Robin
17. Southern Natural Gas Company
18. Tenneco, Inc.
19. Texas Eastern Transmission Corporation
20. Texas Gas Transmission Corporation
21. Transcontinental Gas Pipeline Corporation
22. Transwestern Pipeline Company
23. Trunkline Gas Company
24. United Gas Pipe Line Company

TABLE 2

Mergers and Acquisitions Involving Major Interstate Natural Gas Transmission Companies 1977-1986

1982

Northwest Energy Corp. (parent of Northwest Gas Pipeline Company) purchases controlling interest in Cities Service Gas Company (now Northwest Central Gas Company)

Burlington, Inc. acquires El Paso Natural Gas

1983

Williams Companies acquires Northwest Energy Corp.

CSX Corp. acquires Texas Gas Transmission

MidCon Corp. acquires Mississippi River Transmission

Northern Natural Gas (now InterNorth) acquires Belco Petroleum

1984

Houston Natural Gas (intrastate company) acquires Transwestern Pipeline

Houston Natural Gas acquires Florida Gas Transmission

1985

Northern Natural Gas merges with Houston Natural Gas creating largest interstate network under one parent corporation (now Enron, Corp.) to avoid takeover by Coastal Corp.

Coastal Corporation acquires ANR Pipeline

MidCon Corp. acquires United Energy Resources (parent of United Gas Pipe Line Co.)

1986

Occidental Petroleum acquires MidCon Corp.

Arkansas-Louisiana acquired Mississippi River Transmission

TABLE 3

Parameter Estimates

	Model I		Model II		Model III	
Parameter	Estimate	Std Error	Estimate	Std Error	Estimate	Std Error
α_0	3.482**	(.854)	2.580	(4.227)	12.939**	(2.594)
α_Y	6.568**	(.800)	6.042**	(.867)	5.774**	(.781)
α_L	.447**	(.008)	.452**	(.008)	.453**	(.008)
α_E	.553**	(.008)	.548**	(.008)	.547**	(.008)
α_H	-1.375**	(.072)	-1.467**	(.072)	- .868**	(.050)
α_P	-5.218**	(.184)	-5.489**	(.183)	-3.073**	(.115)
β_{YY}	2.666**	(.918)	3.685**	(.942)	.705	(.724)
β_{LL}	.057**	(.021)	.060**	(.021)	.092**	(.022)
β_{EE}	.057**	(.021)	.060**	(.021)	.092**	(.022)
β_{HH}	- .963**	(.140)	-1.018**	(.140)	- .531**	(.080)
β_{PP}	1.516**	(.445)	1.056**	(.439)	-1.062**	(.153)
β_{LE}	-.057**	(.021)	-.060**	(.021)	- .092**	(.022)
β_{LH}	-.108**	(.023)	-.103**	(.023)	- .147**	(.023)
β_{LP}	.098**	(.028)	.114**	(.028)	.092**	(.024)
β_{EH}	.108**	(.023)	.103**	(.023)	.147**	(.023)
β_{EP}	-.098**	(.028)	-.114**	(.028)	- .092**	(.024)
β_{HP}	1.468**	(.186)	1.309**	(.184)	.065	(.091)
β_{YL}	-.077**	(.021)	-.097**	(.021)	- .041**	(.013)
β_{YE}	.077**	(.021)	.097**	(.021)	.041**	(.013)
β_{YH}	-.259	(.190)	-.041	(.187)	.512**	(.072)
β_{YP}	-1.815**	(.474)	-1.170**	(.464)	1.285**	(.163)
β_{YT}	-.058	(.127)	-.202**	(.083)	.013	(.057)
θ_T	6.508**	(.490)	.422**	(.413)	.039	(.389)
θ_{TT}	-1.107**	(.103)	-.051**	(.079)	.022	(.076)
λ	-1.394*	(.695)	-1.068**	(.462)		
ϕ_{D2}	-4.800**	(1.051)	-1.112**	(.539)	- .898*	(.512)
ϕ_{D3}	-2.474	(1.544)	-1.364*	(.762)	- .983	(.709)
Firm Effects	No		Yes		Yes	
System R^2 (Weighted)	.4360		.9003		.9311	

*Significant at the 10% level.
**Significant at the 5% level.

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

TABLE 4

Average Annual Change in Output, Total Factor Productivity Growth, and Contributing Factors

Year	$\dot{Y}$	TFP	Technical Change $-\dot{T}$	Scale Economies $(1 - \epsilon_{cy})\dot{Y}$	Disequilibrium $-\Sigma\dot{X}_i(S_i - S^*_i)$
			<u>Model I</u>		
1977-78	2.95%	1.34%	1.17%	.07%	.10%
1978-79	8.27	5.84	6.05	- .30	.09
1979-80	1.59	.25	.73	- .51	.03
1980-81	3.21	1.42	1.46	- .13	.09
1981-82	- 7.83	-6.66	-5.87	- .42	- .37
1982-83	-12.81	-8.33	-7.26	- .15	- .92
1983-84	4.26	2.16	2.24	- .64	.36
1984-85	-12.31	-9.25	-9.65	.81	- .41
Average	- 1.58	-1.65	-1.39	- .16	- .13
			<u>Model II</u>		
1977-78	2.95%	1.31%	1.01%	.19%	.10%
1978-79	8.27	5.79	6.42	- .72	.09
1979-80	1.59	.16	1.27	-1.14	.03
1980-81	3.21	1.42	1.50	- .17	.09
1981-82	- 7.83	-6.92	-5.40	-1.15	- .37
1982-83	-12.81	-8.85	-6.41	-1.52	- .92
1983-84	4.26	2.08	2.62	- .90	.36
1984-85	-12.31	-9.87	-9.18	- .28	- .41
Average	- 1.58	-1.86	-1.02	- .71	-.13
			<u>Model III</u>		
1977-78	2.95%	1.11%	2.51%	-1.39%	.00%
1978-79	8.27	2.86	9.04	-6.18	.00
1979-80	1.59	3.07	6.24	-3.17	.00
1980-81	3.21	.95	3.58	-2.63	.00
1981-82	- 7.83	.50	- .59	1.10	.00
1982-83	-12.81	.79	-8.24	7.45	.00
1983-84	4.26	-4.76	- .69	-4.07	.00
1984-85	-12.31	-7.51	-16.03	8.52	.00
Average	- 1.58	- .57	- .52	- .05	.00

TABLE 5

Short and Long Run Elasticity Estimates*

Allen-Uzawa Elasticities

	Short Run			Long Run		
	Model I	Model II	Model III	Model I	Model II	Model III
O_{LL}	-0.4263	-0.4144	-0.3438	- 1.3861	-1.1287	-1.9841
O_{EE}	-0.3442	-0.3417	-0.2848	- .4883	- .7139	-1.2740
O_{HH}				-10.0543	-4.9907	-2.9608
O_{PP}				- 1.9951	-1.0363	- .8204
O_{LE}	0.4263	0.4144	0.3438	- .4116	- .2686	- .5764
O_{LH}				3.4596	1.7856	1.5062
O_{LP}				- 2.1303	- .8932	- .0976
O_{EH}				- 1.9389	- .8723	- .5170
O_{EP}				1.9268	1.1318	1.4291
O_{HP}				7.4898	3.7298	2.0549

Morishima Substitution Elasticities

	Short Run			Long Run		
	Model I	Model II	Model III	Model I	Model II	Model III
F^m_{LE}	.7705	.7561	.6287	.0767	.4453	.6975
F^m_{LH}				13.3139	6.7763	4.4669
F^m_{LP}				- .1353	.1432	.7228
F^m_{EL}	.7705	.7561	.6287	1.0761	.9264	1.5224
F^m_{EH}				8.1154	4.1185	2.4438
F^m_{EP}				3.9218	2.1682	2.2495
F^m_{HL}				3.0155	1.9697	3.0960
F^m_{HE}				- .7243	.1684	.7873
F^m_{HP}				9.4849	4.7662	2.8753
F^m_{PL}				1.0434	.9850	1.9593
F^m_{PE}				.8998	.9556	1.7268
F^m_{PH}				12.6125	6.2647	3.6670

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

TABLE 6

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 7

Consumer Prices and Expenditures

	Quantity Purchased BCF	Actual $/MCF	Estimated Free Market $/MCF	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 8

Prices, Quantities, and Expenditure Savings
By Type of Consumer

Residential

	Quantity Purchased BCF	Actual $/MCF	Estimated Free Market $/MCF	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

Commercial

	Quantity Purchased BCF	Actual $/MCF	Estimated Free Market $/MCF	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	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

Table 8 (continued)

Industry

	Quantity Purchased BCF	Actual $/MCF	Estimated Free Market $/MCF	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

Pipelines*

	Quantity Purchased BCF	Actual $/MCF	Estimated Free Market $/MCF	Savings $ Billion
1978	354	$1.10	$1.09	-$ 34
1979	407	1.40	2.06	- 327
1980	407	1.91	3.29	- 630
1981	420	2.46	4.17	- 791
1982	360	2.92	3.27	- 159
1983	271	3.17	2.54	145
1984	306	3.00	2.76	67
1985	277	3.01	2.21	206
			Total	-$1,522

TABLE 9

Variable Cost and Productivity

	Variable Cost Increase* $ Million	Model I: TFP With Free Market Prices	Model I: Free Market TFP - NGPA TFP	Model II: TFP With Free Market Prices	Model II: Free Market TFP - NGPA TFP	Model III: TFP With Free Market Prices	Model III: Free Market TFP - NGPA TFP
1978	$ 33.9	$ 1.92	$ .84	$ 1.86	$ .84	$ .61	$ .74
1979	327.1	4.26	.62	4.16	.61	1.87	.63
1980	630.1	- .98	.46	- 1.09	.48	2.35	-2.57
1981	790.7	.70	.62	.70	.62	- .40	-2.37
1982	158.7	-8.84	- .60	- 9.15	- .60	-3.53	-6.87
1983	-144.8	-9.69	-3.20	-10.25	-3.20	- .94	-7.80
1984	- 66.7	.15	.94	.05	.93	-5.30	3.73
1985	-205.6	-8.83	-1.47	- 9.27	-1.47	-9.06	-3.50
Total	$1,521.9						

*Value is the total for the 24 firms in our sample, not the entire interstate transmission industry.

APPENDIX

The measurement of the output and input variables are modifications of 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. These reports are not published or distributed, but can be purchased 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.

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. Tons of steel are derived by the following engineering based formula, as reported in Callen (1978):

$$\text{Tons} = .382\ D^2M,$$

where D = weighted average pipeline diameter
M = miles of transmission pipeline.

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 (OGJ) 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. Christensen-Jorgenson (1969) type service prices for capital are used. Capital service prices are derived by:

$$W_t^i = \frac{1 - U_t Z_t - K_t}{1 - U_t} \left[q_{t-1}^i r_t + q_t^i d_t^i - (q_t^i - q_{t-1}^i) \right]$$

where t = time period
U_t = corporate profits tax rate
Z_t = present value of depreciation deductions for tax purposes on a dollar's investment over the life time of the asset
K_t = investment tax credit rate
r_t = (weighted average) rate of return on capital
d = rate of depreciation
q_t = price index for new capital of type k
i = type of capital, compressors or line pipe.

To calculate the present value of depreciation allowances (Z), we assume straight line depreciation. Thus,

$$Z_t^i = \frac{1}{Y^i r} \left[1 - \left(\frac{1}{1 + r} \right)^{Y^i} \right]$$

where Y^i = economic life span of asset i, 12.7 years for compressors (Hulten and Wykoff, 1981) and 40 years for linepipe (BIR Bulletin F).

The investment tax credit (K) varies over time and firm, depending on how rapidly the firm depreciates the assets and whether it has an employee stock option program (ESOP), which allows for an additional 0.5% tax credit. The acquisition cost of new compressors, per horsepower (q^c), is derived from the OGJ-Morgan gas pipeline cost index and cost per horsepower estimates for new compressors. The acquisition cost of new pipeline, per ton of steel (q^p), is derived in the following manner. The OGJ publishes annual costs for construction of new pipeline segments, by diameter of pipe. The log of average cost per mile of pipe is regressed on time and the log of pipe diameter, i.e.:

$$\ln(\$/M) = 8.2465 + 1.2323 \text{ Ln}(D) + .1318 \text{ T}.$$

Data for 1976-1985 are used. All variables are significant at the 5% level or better, $R^2 = .7766$. Next, the cost per mile of new pipe is estimated using the above model and the firm and time specific weighted average diameter of the firm's pipeline network. Finally, the estimated cost per mile is deflated with the OGJ-Morgan gas pipeline cost index for steel line pipe and converted into a cost per ton:

$$\$/\text{ton} = \frac{\text{deflated } \$/M}{.382\ D^2}$$

The rate of return on capital is the weighted average return on the firm's long term debt. The rate of depreciation for compressors is assumed to be 0.0787, corresponding to a 12.7 year life span, and 0.0250 for pipelines, corresponding to a 40 year life span.

The ex post rate of return on capital is calculated on the value added basis. 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. All prices and quantities are scaled such that the geometric mean equals zero.

Capacity utilization is measured by the load factor of the pipeline, that is, the ratio of average daily delivery to peak day delivery. Average daily delivery is the sum of annual sales and gas transported for others, net of gas transported by others, divided by 365. Peak delivery is calculated as the average of the consecutive three day peak deliveries minus storage withdrawals.

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Endnotes

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. Outspoken opponents of NGPA included Kathleen F. O'Reilly, executive director of the Consumer Federation of America (O'Reilly, 1978), Lee C. White, former chairman of the Federal Power Commission (Rowen, 1978), and Senators Don Riegle and Percy, and Congressmen Dingell and Newton Steers, Jr. (95th Congressional Record, 1978).

4. See Pasztor (1986).

5. 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).

6. 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.

7. By February 1977 there were "...more than 4,000 manufacturing plants idle for lack of gas, a million workers laid off, and hundred of schools closed". (Tussing and Barlow, page 114.)

8. Pipeline configuration includes the pipe diameter, length, and location, and the number and location of compressor stations. Once in place, the configuration is difficult to alter.

9. The industry does have the incentive to cost minimize, particularly in the short run. Firm costs are scrutinized during rate hearings. Costs are required to be well documented and reasonable; FERC has been known to disallow some costs. More importantly, 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. 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 were very few formal rate hearing cases during the period we analyze.

10. The spot market created an alternative to pipeline system purchases of natural gas. Spot market prices responded quickly to market signals, unlike the contractual arrangements made for system sales. Coupled with changes in regulation to encouraged the unbundling of services and open access to transport services, the spot market enabled increasing numbers of customers to go off-system to purchase supplies in the now largely deregulated wellhead market and contributed to the restructuring of the natural gas market.

11. 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.

12. The labor required to operate and maintain the compressor stations and linepipe 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, as discussed by Cookenboo, Jr. (1955). Administrative labor requirements are much less rigid. The labor input for our sample increased by 16.1% over the first five years, while wages increased 42.4%. In the next four years wages increased 22.9% and labor inputs declined 14.4%. In contrast, the two capital inputs increased 3.5 and 4.8% during the first five years, and increased by .1 and 1.1% during the next four years. Compressor capital prices fell throughout the sample time period; linepipe prices increase 68.8% the first five years and then declined 32.8% in the next four years. This demonstrated flexibility in labor lends support

for our treatment of labor as a variable input.

13. Berndt and Hesse (1986), page 7.

14. Transmission firms often act as merchants of natural gas, serving as intermediaries between producers and distributor, and also engage in some storage activities. However, our focus here is on their transport services, which are becoming increasing important as a separable activity. One company, Columbia Gulf Pipeline, engages exclusively in transport for others.

15. 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.

16. The quantity of line pipe capital services is calculated via Callen's (1986) methodology, equation A8, page 320: $P = .382d^2L$; where P = pipeline capital services, d = weighted average diameter, and L = miles of transmission pipelines.

17. For the restricted cost function to be concave in factor prices the Hessian matrix, $H=[M^2CV/Mw_iMw_j]$ is negative semidefinite. Alternatively, we can examine the matrix of short run Allen-Uzawa partial elasticities, $A = [F_{ij}]$, which also should be negative semidefinite. In addition, the Hessian matrix of quasi-fixed factors, $B = [M^2CV/MX_hMX_k]$ is positive semidefinite for all observations.

18. The variable cost elasticity is defined as: $g_{cvy} = (MCV/MY)(Y/CV) = MlnCV/MlnY$. The long run cost elasticity is: $g_{cy} = (1 - EMlnCV/MlnX_k)^{-1}g_{cvy}$ where $EMlnCV/MlnX_k$ is the sum of the shadow shares of the fixed factors, evaluated at the observed levels. 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, g_{yc}, is defined as the inverse of the cost elasticity.

19. A discrete approximation to the continuous measure of long run technical change is defined by: $T = ½(g_{cyt} + g_{cyt-1})\dot{Y} - E½(S^*_{it} + S^*_{it-1})\dot{X}_i$, 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 optimal total long run cost. In the case of constant returns to scale and long run equilibrium when the firm is producing at the minimum point of its long run average cost curve, T = TFP. For non-constant returns to scale, the formula must be adjusted to:
$TFP = T + (1 - g_{cy})\dot{Y} - E(S_i - S^*_i)\dot{X}_i$; where S_i = input share in terms of total long run cost, with quasi-fixed inputs at observed levels.

20. If the estimated shadow prices from equation 5, which are the ex post rates of return, differs from the market prices for capital, capital levels are nonoptimal. The optimal levels are estimated by solving $-MCV/MX^*_k = W_k$. However, for the transmission industry, regulation has kept the rate of return consistently above the market price. We cannot use the difference between the shadow and market prices to evaluate the extent of disequilibrium; it would always indicate below optimal levels of capital. Therefore, in estimating the optimal levels of the fixed capital services, we assume the industry was in long run equilibrium at the time of peak deliveries, 1972. The ratio of production to peak year production is applied to the observed level of capital for each year to determine the optimal level of capital services. This method assumes that the optimal mix of compressors and line pipe have not changed in the past 20 years. To the extent that there was excess capacity during peak production, our estimate of overcapitalization is understated. A five percent overestimate of the optimal capital levels translates to a 1.5% overestimate of the variable factors' long run elasticities and a 6.3% over estimate of the capital long run elasticities.

21. The only other elasticity estimates of the industry are from Streitwieser and Sickles (1992) are derived from a translog production function, which assumed long run equilibrium. They found all input pairs to be Allen-Uzawa and Morishima substitutes.

22. U.S. crude oil price control ended in 1981. This, coupled with declining demand and the weakening of OPEC to control output led to a steady drop in crude oil prices.

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

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

25. 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% 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.

26. Domestic oil producers are the marginal suppliers unless the world price of oil rises above the cost of production for U.S. domestic oil producers.

27. There have been no previous bankruptcies in the interstate transmission industry. It is unknown if federal regulators would allow a firm to declare bankruptcy or what actions it would take to prevent such an occurrence.