McMASTER UNIVERSITY
FACULTY OF BUSINESS

Production, Efficiency, and Welfare in the U.S. Natural Gas Transmission Industry

By

JEFFREY L. CALLEN
Assistant Professor of
Finance & Business Economics

FACULTY OF BUSINESS
McMASTER UNIVERSITY
HAMILTON, ONTARIO, CANADA

Research and Working Paper Series: No. 137
July, 1977

Production, Efficiency, and Welfare
in the U.S. Natural Gas Transmission Industry

by

Jeffrey L. Callen

McMaster University

Revised July, 1977

In a recent conference, Leland Johnson criticized the asymmetry between the voluminous theoretical literature and the absence of empiricial work on the Averch-Johnson-Wellisz (A-J-W) hypothesis. The research engendered by Johnson's criticism has led to other imbalances. With one notable exception,[1] the empirical A-J-W literature concentrates on the electrical generating industry disregarding the potential benefits from intellectual diversification.[2] Also, much effort is expended testing for the overcapitalization phenomenon but the attendant welfare implications are virtually ignored. This paper tries to redress some of these imbalances by (i) investigating the A-J-W hypothesis in the U.S. interstate natural gas transmission industry and (ii) analysing the social welfare impact of rate of return regulation on this industry.

In what follows, Section I formulates the optimization models which are used to simulate the input-output decision of a natural gas transmission company. Of the four models which are developed in this section, two are independent of the regulatory environment while the other two are constrained by it. A brief description of the constraint employed by the Federal Power Commission (FPC) to regulate interstate transmission companies precedes the formulation of the constrained models. Also, in this section, the input distortions which are potential consequents of rate of return regulation are discussed. Section II compares the simulated solutions with data from a comprehensive sample of natural gas transmission companies. The model which predicts the best is presumed to reflect the underlying behaviour of the industry. Section III analyses the social welfare implications of regulating the industry by comparing the benefits of rate of return regulation to those obtainable from marginal cost pricing.

I. The Models

A. Some Preliminary Assumptions

Transmission revenues are derived from three sources: the transmission and sale of natural gas to other transmission companies and retail distributors, commonly known as sales for resale Q_1; the transmission and direct sale of gas to large industrial corporations, commonly known as main line industrial sales Q_2; and the non-sale transmission of gas for other pipelines Q_3 net of own gas transmitted by other pipelines Q_4. It is assumed that Q_2, Q_3 and Q_4 are proportional to Q_1. This assumption is necessary for computational simplicity and reasonable because transmission activities other than sales for resale are minor or negligible for most large transmission companies.[3] Other assumptions concerning the models follow. The demands for Q_1 and Q_2 are governed by constant elasticity demand function $P_1(Q_1)$ and $P_2(Q_2)$. P_3 and P_4, the prices of Q_3 and Q_4, are constant. Transmission costs, both fixed and variable but excluding the cost of the gas, are proportional to either horsepower capacity H or line-pipe capacity K. The wholesale purchase price of a unit of gas $\emptyset$ is constant.

B. The Unconstrained Models

In the absence of a regulatory constraint, either cost minimization or profit maximization are assumed to determine a transmission company's behaviour. The firm's behaviour is further limited by the technology relationship developed in Appendix A (constraint 2). Specifically, the profit maximizing (PM) model can be represented by:

Maximize

Q_1, H, K

(1) $$V = (1-\tau)[P_1(Q_1)Q_1+P_2(Q_2)Q_2+P_3Q_3-P_4Q_4-\phi(Q_1+Q_2)]$$
$$-\ [(1-\tau)W_v+(r-\tau d_H)W_F]H\ -\ [(1-\tau)P_v+(r-\tau d_K)P_F]K$$

subject to

(2) $$Q_1 = AH^{.27}K^{.9}$$

where

P_F = fixed costs per unit of line-pipe capacity

W_F = fixed costs per unit of horsepower capacity

P_v = variable costs per unit of line-pipe capacity

W_v = variable costs per unit of horsepower capacity

τ = corporate tax rate

r = firm's (weighted average) cost of capital

d_H = depreciation rate for horsepower related equipment

d_K = depreciation rate for line-pipe

A = scale constant

The cost minimizing (CM) model solves for the same input ratio as the PM solution and an indeterminate output level.

C. The Regulatory Constraint

The revenues earned by an interstate natural gas transmission company on its sales for resale, also called jurisdictional sales, are regulated by the FPC through the Atlantic Seaboard cost allocation formula. The initial step in applying this formula necessitates estimating the cost of service - operating expenses, taxes, depreciation and a "fair" return to shareholders - on the basis of test-year data. The components of the cost of service are then allocated to either a demand or commodity cost classification. Theoretically, the demand classification is comprised of those costs incurred providing fixed pipeline capacity. The commodity classification, on the other hand, should include both the cost of the gas and the variable costs of transmitting it to the customer. In practice, the Atlantic Seaboard formula splits most costs evenly between the two classifications with some important exceptions. The cost of the gas and pipeline produced gas expenses are allocated entirely to the commodity classification. Most, but not all, compressor and production expenses are allocated to the commodity classification. Demand charges levied by one transmission company on another in interstate sales are included in the buyer's demand classification.

Revenues derived from other than transmission-sales activities are netted against the cost of service. Non-sales transmission and storage revenues are credited wholly to the commodity classification. Other revenues, which are usually derived from the sale of natural gas by-products, are credited equally to each classification.

The next step in applying the Atlantic Seaboard formula involves allocating costs between jurisdictional and non-jurisdictional markets. The commodity classification is weighted by the ratio of jurisdictional to total annual sales. Demand is weighted by the ratio of jurisdictional to total "firm" sales during a three day sustained peak period. The sum of the two is the cost of service attributable to the jurisdictional market which serves as an upper bound on the revenues the company is allowed to earn in the jurisdictional market.

D. The Constrained Models

Two possible objectives are postulated for the constrained models, profit maximization and revenue maximization. In addition to the technology relationship from Appendix A, the firm's input-output decisions are mediated by a regulatory constraint patterned after the Atlantic Seaboard formula.[4] Formally, the constrained revenue maximizing (CRV) model can be represented by:[5]

Maximize

Q_1, H, K

$$V^1 = P_1(Q_1)Q_1+P_2(Q_2)Q_2+P_3Q_3-P_4Q_4 \tag{3}$$

subject to

$$Q_1 = AH^{.27}K^{.9} \tag{4}$$

$$\begin{aligned} P_1(Q_1)Q_1 \leq \frac{Q_{1B}}{Q_{1B}+Q_{2B}} [&1/2\ (P_vK+W_{1v}H+T) + 1/2(P_FK+W_FH+T^1)(1-\delta)s \\ &+ 1/2\ (d_KP_FK+d_HW_FH+d^1T^1) + 1/2\tau^* + 1/2\ P_4Q_4 + M\phi(Q_1+Q_2) \\ &- 1/2\ (\text{miscellaneous revenues})] + \frac{Q_1}{Q_1+Q_2} [1/2\ (P_vK+W_{1v}H+T) \\ &+ 1/2(P_FK+W_FH+T^1)(1-\delta)s + 1/2(d_KP_FK+d_HW_FH+d^1T^1) + 1/2\tau^* \\ &+ 1/2\ P_4Q_4+(1-M)\phi(Q_1+Q_2) + W_{2v}H - P_3Q_3 \\ &- 1/2\ (\text{miscellaneous revenues}) + (\text{gas production and gathering} \\ &\quad \text{expenses})]^6 \end{aligned} \tag{5}$$

where

Q_{1B} = sales for resale peak-load demand

Q_{2B} = main line industrial sales peak-load demand

W_{1v} = variable costs per unit of horsepower capacity allocated to both demand and commodity classifications

W_{2v} = variable costs per unit of horsepower capacity allocated entirely to the commodity classification

M = proportion of production expenses allocated to the demand classification

T = variable costs unrelated to K or H

T^1 = fixed costs unrelated to K or H

τ^* = income and property taxes[7]

s = fair rate of return

δ = accumulated depreciation rate

d^1 = average depreciation rate for assets unrelated to K or H

The constrained profit maximizing (CPM) model is identical to the CRV model except that V^1 (equation (3)) is replaced by V (equation (1)).

E. Regulatory Input Biases

Since the principal variable input into the transmission process, compressor fuel, cannot be forecast accurately,[8] the models simulate, in addition to output, only the two fixed inputs H and K. Nevertheless, the input biases appear in the tradeoff between horsepower capacity and line-pipe capacity since variable costs are assumed to be proportional to the capacity variables. Intuition and the A-J-W literature suggest that, since H has a large variable cost component and line-pipe expenses are trivial, the CPM model's simulated K/H input ratio is always larger than the cost minimizing ratio. This is not the case, however. The CPM input ratio may be less than the corresponding cost minimizing solution. To see this, consider the simple case of a firm which deals only in sales for resale for which the CPM model can be represented by:

$$\underset{K,\,H}{\text{Maximize}}$$

(6) $$V^{111} = (1-\tau)x[Q_1(K,H)] - wH - pK$$

subject to

(7) $$(1-\tau)x[Q_1(K,H)] - \bar{w}H - \bar{p}K - G \leq 0$$

where x is the excess of revenues over the cost of the gas, $Q_1(K,H)$ the production function, and w, p, $\bar{w}$, $\bar{p}$ and G are constants.[9] Forming the appropriate Lagrangian, the first order conditions, excluding the constraint, are:

(8) $$(1-\tau)(1-\lambda)\; x'\; Q_{1K} = p - \lambda\bar{p}$$

(9) $$(1-\tau)(1-\lambda)\; x'\; Q_{1H} = w - \lambda\bar{w}$$

where λ is the multiplier.[10] Therefore, the marginal rate of technical substitution is

(10) $$\frac{Q_{1K}}{Q_{1H}} = \frac{p}{w} + \frac{\lambda p\left(\frac{\bar{w}}{w} - \frac{\bar{p}}{p}\right)}{(w - \lambda\bar{w})}$$

so that the relationship between the CPM and cost minimizing input ratio depends on the a priori indeterminate signs of both $\left(\frac{\bar{w}}{w} - \frac{\bar{p}}{p}\right)$ and $(w - \lambda\bar{w})$. The sign of the former is a function of the relative magnitudes of cost and regulatory parameters which differ from one company to another. The sign of the latter, as seen in equation (9), is determined by whether marginal revenue is greater than or less than the marginal cost of the gas at the optimum. The bias in the CRV model's input ratio is also a function of the sign of $\left(\frac{\overline{w}}{w} - \frac{\overline{p}}{p}\right)$ but in the majority of cases the CRV model's K/H input ratio is less than that of the cost minimizing alternative.

II. Comparing the Data with the Simulated Solutions

A. The Data and the Simulated Solutions

The 1965 output Q, horsepower capacities, and line-pipe capacities of twenty-eight "major" interstate natural gas transmission companies are listed in the first three columns of Table 1.[11] The corresponding simulated PM solutions for each of these firms are presented in the last three columns of Table 1 and the CPM and CRV solutions in Table 2. Detailed descriptions of the data base, and some of the variable and parameter estimates utilized in the simulations are found in Appendix B.

B. Comparing the Input Ratios

On the input side, the predictive abilities of the models are evaluated by comparing the simulated and actual K/H ratios using the absolute prediction error criterion

$$(11) \qquad \left| \frac{(K/H)_S - (K/H)_A}{(K/H)_A} \right|$$

where A and S stand for the actual and simulated solution, respectively. These prediction errors are found in the first three columns of Table 3. Since the CM and PM ratios are identical, their prediction errors are listed in the same column. The fourth column of Table 3 gives the best input model for each firm in the sample where the best input model is the one with the smallest absolute error. Of the twenty-eight cases, the CRV model predicts the best in ten, the CPM model in ten and the CM-PM models in eight. The average absolute-prediction errors are 8.81, .73 and .69 for the CPM, CM-PM and CRV models, respectively.

Table 1 - 1965 Actual and Simulated Profit Maximizing Input-Output Solutions

	Company	Actual (1) Q	(2) H	(3) K	PM (4) Q	(5) H	(6) K
1	Algonquin Gas Transmission	101	31	141	22	15	32
2	American Louisiana Pipeline	200	142	569	52	28	206
3	Atlantic Seaboard	223	48	239	48	11	66
4	Cities Service Gas	420	197	568	92	39	172
5	Colorado Intersate Gas	332	82	235	53	11	57
6	Consolidated Gas Supply	345	104	370	93	19	142
7	El Paso Natural Gas	1,413	746	2,199	524	154	1,172
8	Kentucky Gas Transmission	97	6	65	18	2	15
9	Manufacturers Light and Heat	209	25	227	48	18	60
10	Michigan Gas Storage	90	16	102	22	4	32
11	Michigan Wisconsin Pipe Line	339	200	632	105	39	281
12	Midwestern Gas Transmission	218	27	265	52	9	75
13	Mississippi River Transmission	206	111	248	55	19	96
14	Natural Gas Pipeline Co. of America	659	525	2,080	151	104	660
15	Northern Natural Gas	507	593	1,650	194	132	889
16	The Ohio Fuel Gas	399	33	305	99	13	86
17	Pacific Gas Transmission	194	26	307	51	11	88
18	Panhandle Eastern Pipe Line	600	445	1,256	128	63	406
19	South Texas Natural Gas Gathering	115	5	33	26	2	9
20	Southern Natural Gas	427	277	642	84	60	168
21	Tennessee Gas Transmission	1,055	999	3,233	214	173	931
22	Texas Eastern Transmission	792	902	2,068	203	164	757
23	Texas Gas Transmission	559	276	847	144	62	293
24	Transcontinental Gas Pipe Line	636	647	1,978	198	166	789
25	Transwestern Pipeline	179	64	385	59	23	152
26	Trunkline Gas	314	193	670	91	41	270
27	United Fuel Gas	337	98	187	72	9	68
28	United Gas Pipe Line	1,306	169	1,109	343	85	309

Note: Q is measured in billions of cubic feet of natural gas per year, H in thousands of horsepower, and K in thousands of tons of line-pipe. Details concerning the data sources are found in Appendix B.

Table 2 - Simulated Constrained Profit Maximizing and Constrained Revenue Maximizing Input-Output Solutions

Company	CPM (1) Q	CPM (2) H	CPM (3) K	CRV (4) Q	CRV (5) H	CRV (6) K
1	100	47	123	100	51	120
2	171	189	437	181	101	562
3	221	31	270	221	40	250
4	316	158	443	328	89	548
5	235	46	190	235	37	204
6	93	6	202	129	30	180
7	1,024	44	3,603	1,319	397	2,462
8	95	3	75	97	10	55
9	129	25	135	129	22	139
10	80	38	69	85	14	99
11	350	266	601	365	142	761
12	222	52	222	223	37	248
13	209	68	293	210	53	317
14	613	661	1,793	647	373	2,260
15	272	162	1,220	274	191	1,168
16	394	15	384	408	49	278
17	200	61	245	201	48	265
18	498	237	1,233	500	195	1,311
19	106	8	26	107	6	29
20	421	299	617	424	221	683
21	624	69	4,015	885	601	3,097
22	389	10	3,660	844	652	2,446
23	582	221	947	582	207	966
24	442	61	2,680	626	520	2,073
25	165	156	270	186	72	388
26	296	163	660	299	121	730
27	227	25	181	227	25	182
28	1,402	308	1,002	1,403	271	1,043

Table 3 - Absolute Input Prediction Errors and the Best Input Model Designations

Company	(1) CM-PM	(2) CPM	(3) CRV	(4) Best Input Model
1	.51	.42	.49	CPM
2	.83	.42	.39	CRV
3	.19	.75	.24	CM
4	.54	.03	1.14	CPM
5	.81	.44	.94	CPM
6	1.05	8.35	.67	CRV
7	1.58	27.01	1.10	CRV
8	.25	1.07	.49	CM
9	.31	.38	.30	CRV
10	.35	.72	.10	CRV
11	1.29	.29	.69	CPM
12	.12	.56	.31	CM
13	1.28	.93	1.70	CPM
14	.60	.32	.53	CPM
15	1.41	1.71	1.19	CRV
16	.30	1.84	.38	CM
17	.34	.66	.54	CM
18	1.28	.85	1.38	CM
19	.13	.52	.24	CM
20	.21	.11	.34	CPM
21	.67	16.93	.59	CRV
22	1.01	164.50	.63	CRV
23	.53	.39	.52	CPM
24	.56	13.41	.30	CRV
25	.08	.71	.11	CM
26	.90	.16	.74	CPM
27	2.86	2.80	2.86	CPM
28	.45	.50	.41	CRV

Additional evidence on the predictive superiority of the CRV model can be obtained from the ordinary least squares estimate of b in the equation

(12) $\quad (K/H)_A = b(K/H)_S + \varepsilon$

where ε is assumed to be distributed $N(0,\sigma^2)$. Presumably, if the simulated solution is a good predictor of the actual, the parameter b should equal one. The regression estimate of b for the CRV model is .866. The null hypothesis that b=1 cannot be rejected at the 20% significance level. In the case of the CM-PM model, the estimate is .799 and the null hypothesis is rejected at the 5% level. The hypothesis that b=1 is rejected at the 1% level in the case of the CPM model.

It is worth noting that the extremely poor showing of the CPM model is a function of five "rate base maximizing" solutions which are singular to this model.[12] For example, if these five solutions are deleted, the average prediction error for the remaining firms is only .72. Interestingly, none of the firms in the sample implemented these rate base maximizing solutions even though the technologies are feasible.

C. Comparing Output

The predictive abilities of the models on the output side are evaluated in an identical fashion. The first three columns of Table 4 tabulate the absolute output prediction errors for each of the models while the fourth column designates the best output model. The CRV model predicts the best in eighteen cases with an average prediction error of .12. The CPM model predicts the best in six cases with an average prediction error of .18. In the remaining five cases, both the CPM and CRV models predict equally well. The PM model is an inferior predictor

Table 4 - Absolute Output Prediction Errors, the Best Output Model, and the Best Overall Model Designations

Company	(1) PM	(2) CPM	(3) CRV	(4) Best Output Model	(5) Best Overall Model
1	.782	.007	.007	CPM-CRV	CPM
2	.741	.147	.098	CRV	CRV
3	.787	.010	.008	CRV	CRV
4	.780	.247	.219	CRV	CPM
5	.839	.294	.292	CRV	CPM
6	.731	.731	.624	CRV	CRV
7	.629	.276	.067	CRV	CRV
8	.809	.016	.003	CRV	CRV
9	.769	.382	.382	CPM-CRV	CRV
10	.760	.103	.055	CRV	CRV
11	.691	.033	.077	CPM	CPM
12	.764	.016	.022	CPM	CRV
13	.736	.014	.017	CPM	CPM
14	.770	.069	.018	CRV	CPM
15	.618	.463	.460	CRV	CRV
16	.751	.013	.021	CPM	CRV
17	.739	.031	.036	CPM	CRV
18	.786	.170	.167	CRV	CPM
19	.774	.079	.075	CRV	CRV
20	.802	.014	.006	CRV	CPM
21	.797	.409	.161	CRV	CRV
22	.744	.509	.066	CRV	CRV
23	.743	.041	.041	CPM-CRV	CPM
24	.689	.306	.016	CRV	CRV
25	.670	.078	.042	CRV	CRV
26	.710	.057	.047	CRV	CPM
27	.785	.325	.325	CPM-CRV	CPM
28	.737	.074	.074	CPM-CRV	CRV

with an average prediction error of .75.

Further proof of the superiority of the CRV model in predicting outputs is obtained by regressing for b' in the equation

(13) $$Q_A = b'Q_S + \varepsilon$$

where Q_A is the actual and Q_S the simulated output. Again, only the CRV model's estimate is close to one, specifically, 1.041. The hypothesis that $b'=1$ cannot be rejected at the 10% significance level. The identical hypotheses for the PM and CPM models are rejected at the 1% significance level.

D. Comparing Inputs and Output

The constrained revenue maximizing model is the best overall input-output predictor. The CPM model predicts output reasonably well, but not inputs, while the PM model predicts input proportions, but not output. The model which predicts inputs and output the best on a company by company basis can be determined by comparing both input and output prediction errors simultaneously. In fifteen cases the best overall model is unambiguous since the same model has the smallest input and output prediction errors. In the other thirteen cases the best model is resolved by comparing relative prediction errors assuming input and output prediction errors are weighted equally. For example, Colorado Interstate's CPM output prediction error is only .2% larger than the CRV output prediction error while the input prediction error of the former is 50% less than that of the latter. Consequently, the CPM model is the best overall predictive model for Colorado Interstate. Column (5) in Table 4 lists the best overall predictive model in the sense just defined. The CRV model is seen to predict the best in seventeen cases, the CPM model in eleven cases and the PM model comes in a poor third.

E. The Stability of the Results

It should be noted that, with perhaps one exception, the simulated solutions and the conclusions in this section are quite robust with respect to a wide range of alternative parameter specifications.[13] The exception is the demand elasticity of sales for resale which is estimated to be 1.5. If demand is assumed to be less elastic than 1.5 the superiority of the CRV model over the CPM model is less pronounced, especially on the input side. This occurs because the number of rate base maximizing solutions in the CPM model appears to be a direct function of the size of the elasticity estimate. On the other hand, the CRV model's superiority is even more evident for elasticity specifications greater than 1.5.

III: Efficiency and Welfare Considerations

Showing that regulation has modified the behavior of the natural gas transmission industry addresses only one problem. To the policy-maker, the critically important issue is whether or not regulation is beneficial to society at large. If rate of return regulation leads to input distortions, it also induces the firm to produce at a greater than profit maximizing output level.[14] This tradeoff confronts the policy-maker with the problem: do the benefits of regulation in the U.S. natural gas transmission industry outweigh the costs?[15] This issue can be resolved provided (i) the industry is valued by the social welfare function--the sum of producers' and consumers' surpluses--with its well-known deficiencies and (ii) interpipeline rivalry is neglected.

The marginal cost pricing option (MC), which maximizes the social welfare function, is the benchmark against which the actual data and the simulated solutions are evaluated. The first column of Table 5 lists the maximum yearly benefits obtainable from a marginal cost pricing policy for each of the firms in our sample. The actual benefits and those obtainable from unconstrained profit, constrained profit, and constrained revenue maximization are presented in columns (2) to (5), respectively. These social benefits are gross of regulatory admini-stative costs. Net benefits can be estimated, albeit somewhat crudely, by subtracting $200,000 of average yearly administrative costs per company from the gross figures.[16]

The public policy ramifications of Table 5 are straightforward. The effect of rate of return regulation on increasing output offsets the increased costs of input inefficiencies. Total actual net benefits

Table 5 - Gross Social Welfare Benefits of Marginal Cost Pricing, the 1965 Actual, and the Simulated Solutions

Company	(1) MC	(2) Actual	(3) PM	(4) CPM	(5) CRV
1	123	122	92	122	122
2	159	154	118	149	152
3	221	220	166	220	220
4	182	173	124	166	168
5	112	112	82	110	110
6	413	400	309	308	335
7	999	919	744	859	915
8	95	95	72	95	95
9	247	243	184	229	229
10	78	77	59	75	77
11	333	317	250	316	321
12	161	160	123	159	160
13	111	106	81	108	108
14	436	420	312	413	421
15	512	454	367	401	401
16	403	396	303	394	396
17	114	111	86	111	112
18	371	359	268	356	357
19	33	32	25	32	32
20	270	264	188	263	264
21	829	792	567	711	777
22	745	712	542	595	722
23	345	332	252	335	335
24	610	565	440	519	565
25	150	140	110	135	141
26	253	241	187	239	240
27	471	467	359	453	453
28	453	443	336	446	447

Note: Social welfare benefits are measured in millions of dollars per year.

for the industry are within 5.2% of the marginal cost pricing option, assuming the latter is effected costlessly. In all cases, net benefits are within 15% of the maximum. It is unlikely that other forms of politically acceptable regulatory procedures could do better.

Appendix A

An Engineering Production Function

This Appendix develops a Cobb-Douglas engineering production function for natural gas transmission. T. Robinson derives the following engineering production function for a compressor station and line pipe of length L miles:

$$\text{(A1)} \qquad Q = \frac{(.33)HPs^{.27}d^{1.8}}{L^{.36}}$$

where Q is output in cubic feet, HPs is station horsepower, d is the inside diameter of the line in inches, and the station has a discharge pressure of 1000 psi. If the line is looped, L in (A1) is replaced by Le, the equivalent line length.[17] Assuming all loops are identical

$$\text{(A2)} \qquad Le=L/g^{2}$$

where L is now the length of one loop and g the number of loops. Therefore, (A1) becomes

$$\text{(A3)} \qquad Q = \frac{(.33)g^{.72}HPs^{.27}d^{1.8}}{L^{.36}}$$

Assuming the pipeline is comprised of identically looped line sections, and noting that the number of compressor stations is (L*/gL), (A3) can be manipulated to yield

$$\text{(A4)} \qquad Q = \frac{(.33)gHP^{.27}d^{1.8}}{L^{.09}L^{*.27}}$$

where HP is total system horsepower and L* is total system mileage.

The remainder of this Appendix transforms (A4) into an engineering production function in the variables Q_1, H and K. K is substituted for d in (A4) using the equations:[18]

(A5) $(D-d)/D = .0271$

and

(A6) $K = (7.05)(D^2-d^2)L^*$

where D is the outside line diameter in inches.

Multiplying (A5) by (D+d) gives

(A7) $(D^2-d^2) = (.0271)D(D+d)$

Substituting (A7) into (A6) and approximating D by d yields

(A8) $K = (.382)d^2L^*$

Multiplying (A4) by $L^{*1.17}$, substituting (A8) into the result, and noting that $L^{-.09} = .7$, approximately,[19] yields

(A9) $QL^{*1.17} = (.55)gHP^{.27}K^{.9}$

If the line operates at full capacity and g is treated as a parameter, (A9) becomes

(A10) $Q = AH^{.27}K^{.9}$

where A denotes the scale constant.

The models are developed in terms of variable, not capacity output. Therefore, the constant in (A10) is (theoretically) adjusted by a capacity utilization rate and Q replaced by variable output which is approximated by:

(A11) $(Q_1+Q_2+Q_3-Q_4+F+\Delta Qs)$

where F is compressor fuel consumption and ΔQs is the net change in natural gas storage inventories. If, in addition to the output variables, F and ΔQs are assumed to be proportional to Q_1, substituting (A11) into (A10) yields the Cobb-Douglas engineering technology function:

(A12) $Q_1 = AH^{.27}K^{.9}$

Appendix B

The Data Base, and Some Variable and Parameter Estimates

The 1965 data base was chosen for three reasons. First, 1965 represents a long-run steady-state planning phase, the end of an extensive pipeline construction period characterized by new market penetration.[20] Pipeline construction from 1965 onwards is characterized by growth in existing markets and, therefore, a new planning phase. Second, peak-load demand problems were absent in 1965. It is estimated that in that year 45% of all natural gas transmission lines operated at between 70% and 85% of capacity while the remainder were in the 85% plus range.[21] Third, disaggregated line-pipe capacity data are published for 1965.[22]

Most of the data are found in the FPC annual pipeline statistics, the FPC annual reports, Moody's Public Utilities, the National Petroleum Council (NPC) report on transportation capacities and the J.P. O'Donnel annual cost studies. These sources are sufficiently comprehensive to provide cross-sectional estimates for all but a few parameters. For the rest, industry wide estimates sufficed. Explanations are in order for some of the variable and parameter estimates.

The line-pipe capacity variable is measured in tons of main line steel. The NPC report provides a cross-sectional breakdown of pipeline mileage by outside diameters. Wall thicknesses are estimated by specifying an average industry steel technology, API Standard 5LX-52 with an operating pressure of 1000 p.s.i.

Although peak-load demand data are unavailable, the U.S. Bureau of Mines publishes a cross-sectional breakdown of main line industrial sales into interruptible and firm categories. Therefore, the proportion of peak load jurisdictional sales to total peak load sales can be estimated by $(Q_{1A}/Q_{1A} + \rho Q_{2A})$ where the A subscript denotes the 1965 actual outputs of Q_1 and Q_2 and ρ is the proportion of firm to total main line industrial sales.

The unit line-pipe capital cost is derived by summing the company's line-pipe related capital expenditures in the 1965 FPC accounts and dividing the result by K.[23] This book value figure is employed in the regulatory constraint and in the depreciation expense component of the objective function. In the remainder of the objective function, a 1965 constant dollar unit capital cost is used. This figure is obtained by adjusting all line-pipe related capital expenditures over the lifetime of the firm by a pipeline construction price index. The unit horsepower capacity capital cost is estimated in exactly the same fashion although the assumption of a constant unit cost is apparently contradicted by the potential economies of scale in horsepower generation. Average cost per horsepower generated declines with the capacity of a compressor-prime mover unit up to some technological limit. In practice, there are severe limitations placed on the size of the compressor unit by the characteristics of the gas flow, the need for operational flexibility and the dynamics of horsepower capacity utilization so that in 1965 average capacity was only from one to two thousand horsepower per unit.[24] Therefore, the assumption of a constant unit cost is not unreasonable. The wholesale price of the gas is estimated by average purchased gas expenditure. This figure is also the implicit price of pipeline produced gas.

The scale constants in the production function and the demand functions are estimated from the data and the appropriate functional forms. For example, the scale constant in the production function is determined by $(Q_{1A}/H_A^{.27}K_A^{.9})$ where the A subscript again denotes the 1965 actual values.

Accumulated depreciation in the regulatory constraint is expressed as a percentage of the undepreciated cost of the company's assets. This rate is calculated by dividing the FPC account "Accumulated provisions for depreciation, amortization and depletion" by "Total gas plant".[25]

A weighted average cost of capital is calculated for each company using the book value capitalization rates of debt, preferred and equity capital as of December 31, 1965. The pre-tax cost of debt is determined from Moody's rating of the most recent (pre-1966) bonds issued by each pipeline company. The cost of preferred capital is taken to be the most recent (pre-1966) imbedded preferred share dividend yield. The after-tax cost of equity capital is derived from the familiar dividend yield equation where the growth rate is measured by the multiplicand of the retention rate and the return on (book value) equity capital, averaged over the period 1965 to 1970. In those cases where the shares of the subsidiary pipeline company did not trade on the open market, the cost of capital of the parent is used.

The following parameter values are assumed to hold on an industry-wide basis. The fair rate of return is 6.5% which is the least upper bound on the return allowed pipeline companies under FPC jurisdiction from 1962 to 1967.[26] The straight line depreciation rates for K, H and other assets are 3.2%, 3.9% and 4.5%, respectively. These depreciation rates are commonly employed in FPC rate case proceedings.[27] The long-run demand elasticity estimates are 1.5 for sales for resale and 4.0 for main line industrial sales. These elasticity estimates are borrowed from the McAvoy and Noll study. It is assumed that 15% of interpipeline gas sales revenues are demand charges and the rest commodity charges. This figure is based on the original Atlantic Seaboard case[28] and appears to be the only estimate available. Fortunately, the simulations are insensitive to this particular parameter.

FOOTNOTES

*Assistant Professor of Finance and Business Economics, McMaster University This paper is adapted from my Ph.D. thesis submitted to the Faculty of Management Studies, University of Toronto and written under the guidance of G. David Quirin, Basil Kalymon, Frank Mathewson, and Jack Sawyer. I am also indebted to Varouj Aivazian, George Borts, Danny Frances, Stan Laiken and Herbert Mohring for their comments on earlier drafts.

[1]Paul McAvoy and Roger Noll also study the natural gas transmission industry but their methodology differs fundamentally from ours. They are concerned with the impact of regulation on prices rather than inputs and output. They also disregard the social welfare ramifications of pipeline regulation.

[2]Foremost among this expanding literature are the studies by Leon Courville, Thomas Cowing, Paul Hayashi and John Trapani, H. Craig Peterson, and Robert Spann.

[3]Especially those companies which comprise our sample. See footnote 11 below and FPC Statistics 1965.

[4]Constraint (5) is a proxy for the Atlantic Seaboard formula. The first set of square brackets on the right-hand side of the inequality contains the demand costs. These are weighted by the ratio of jurisdictional to total firm sales during the peak period of the test-year. The second set of square brackets contains the commodity costs which are weighted by jurisdictional to total sales during the entire test-year. Therefore, those revenues which the firm may earn in the jurisdictional market are restricted by constraint (5) not to exceed *ex ante* the

4 cont'd

sum of demand and commodity costs attributable to the jurisdictional market in the test-year. Although uncertainty about sales and regulatory lag may cause the constraint to be violated *ex post*, it is assumed that these effects are not endogenized by the firm during the pipeline planning stage and any excess profits earned thereby are treated as windfall gains.

[5]The constrained models are solved by a dual iteration-linearization technqiue described by Callen, pp. 102-07.

[6]Miscellaneous revenues, and gas production and gathering expenses are treated as constants. The allowance for working capital and interest during construction are not part of the constraint formulation since they are trivial amounts and the relevant data are not available.

[7]τ^* is treated as a function of the other parameters and variables, i.e.,

$$\tau^* = \tau[P_1(Q_1)Q_1 + P_2(Q_2)Q_2 + P_3Q_3 - P_4Q_4 - \phi(Q_1+Q_2) - W_VH - P_VK$$
$$- (d_KP_FK + d_HW_FH) - T - \text{other deductions on corporate income taxes}]$$
$$+ \text{other state and local (property) taxes.}$$

[8]Natural gas compressor-prime mover units are either reciprocating-gas engine or centrifugal-gas turbine. The latter consume a significantly greater amount of fuel per horsepower generated than the former, for a given horsepower capacity. Therefore, without an inventory of compressor types (for each firm) fuel consumption cannot be estimated. Nor is it reasonable to assume a representative inventory since the proportion of compressor-prime mover types differs dramatically among firms for which the data are available. See J.T. Jensen and T.R. Stauffer, pp. 93-95.

[9] Using the previous notation

$$w = (1-\tau)W_V + (r-\tau d_H)W_F$$

$$p = (1-\tau)P_V + (r-\tau d_K)P_F$$

$$\overline{w} = (1-\tau)W_V + ((1-\delta)s + (1-\tau)d_H)W_F$$

$$\overline{p} = (1-\tau)P_V + ((1-\delta)s + (1-\tau)d_K)P_F$$

$$G = (1-\tau)T + ((1-\delta)s + d^1)T^1 + \text{gas production and gathering expenses}$$

$$+ \tau \text{ (other deductions on corporate income taxes)}$$

$$- \text{ other state and local (property) taxes}$$

[10] E.E. Zajac shows that $0<\lambda<1$ if the constraint is binding.

[11] Our sample is restricted to major pipeline companies as defined by the FPC Statistics 1965, p. VIII. The remaining interstate pipeline companies are either distribution companies or have small pipeline systems which cannot be described by a Cobb-Douglas production technology. In addition, four of the thirty-two majors were excluded because they primarily transport gas owned by their affiliates. The excluded majors are: Chicago District Pipeline, Columbia Gulf Transmission, Florida Gas Transmission and Humble Gas Transmission.

[12] The rate base maximizing solutions require large K/H ratio technologies. These solutions have CPM prediction errors greater than three in Table 3.

[13] See Callen, pp. 108-22. Included in the sensitivity analysis is the specification that ϕ is a constant elasticity supply function with a supply elasticity of five.

[14] Except for the pathological case described by William Baumol and Alvin Klevorick.

[15] The policymaker could theoretically utilize this tradeoff to set socially optimal rates of return. See Jeffrey Callen, G. Franklin Mathewson, and Herbert Mohring.

[16] Paul McAvoy estimates that the FPC and the pipeline industry spent $3.5 million and $2.5 million, respectively, in 1968 or abour $200,000 per company.

[17] See American Gas Association, pp. 8/10-8/11.

[18] (A5) assumes a discharge pressure of 1000 psi. and a 5LX-52 high test line pipe technology. See D.L. Katz, et al., pp. 628-30. (A6) is derived by multiplying the volume of steel in an open cylinder by the weight of steel per unit of volume.

[19] Station spacing is usually (and optimally) constant for a given pipeline, although it differs from one pipeline to another. Typically L varies from 30 to 100 miles so that $L^{-.09}$ varies from .74 to .66.

[20] See FPC Statistics 1965, p. VIII.

[21] See FPC National Gas Survey, pp. 129-30.

[22] See the NPC report.

[23] The assumption that line-pipe unit costs are constant is not unreasonable. The following 1960-62 data and cost estimates give some indication of unit costs (on a per ton basis) for 24, 30 and 36" pipelines constrained to a working pressure of approximately 950 psi:

23 cont'd

Outside Diameter (in)	Wall Thickness (in)	Actual Data ($)	Nordberg Estimates ($)	Columbia Gas Estimates ($)
24	.312	355	360	378
30	.375	339	367	361
36	.438	...	330	352

The Nordberg estimates are found in American Gas Association, p. 8/95. The actual cost data as well as the Columbia Gas estimates are from Laurence Rosenberg, p. 215.

[24] See the NPC report. There are modest economies of scale in the size of the compressor stations. However, the cost of a reasonably sized station is proportional to the number and size of the compressor units and, therefore, horsepower capacity.

[25] See FPC Statistics.

[26] See Stephen Breyer and Paul McAvoy, P. 31.

[27] See, for example, 13 FPC 53 (1954).

[28] See 11 FPC 521 (1952) and 11 FPC 57 (1952).

REFERENCES

American Gas Association, Gas Engineers Handbook, New York 1965.

H. Averch and L.L. Johnson, "Behaviour of the Firm Under Regulatory Constraint," Amer. Econ. Rev., Dec. 1962, 52, 1053-69.

W.J. Baumol and A.K. Klevorick, "Input Choices and Rate-of-Return Regulation: An Overview of the Discussion," Bell J. Econ., Fall 1970, 1, 162-90.

S.G. Breyer and P.W. McAvoy, Energy Regulation by the Federal Power Commission, Washington 1974.

J.L. Callen, "Production, Efficiency, and Welfare in the U.S. Natural Gas Transmission Industry," unpublished doctoral dissertation, University of Toronto, 1976.

__________, G.F. Mathewson, and H. Mohring, "The Benefits and Costs of Rate of Return Regulation," Amer. Econ. Rev., June 1976, 66, 290-97.

L. Courville, "Regulation and Efficiency in the Electric Utility Industry," Bell J. Econ., Spring 1974, 5, 53-74.

T.G. Cowing, "The Effectiveness of Rate-of-Return Regulation: An Empirical Test Using Profit Functions," in Melvyn Fuss and Daniel McFadden, eds., Production Economics: A Dual Approach to Theory and Applications, Amsterdam forthcoming.

P.M. Hayashi and J.M. Trapani, "Rate of Return Regulation and the Regulated Firm's Choice of Capital-Labor Ratio: Further Empirical Evidence on the Averch-Johnson Model," Southern Econ. J., Jan. 1976, 42, 384-98.

J.T. Jensen and T.R. Stauffer, "Implications of Natural Gas Consumption Patterns for the Implementation of End-Use Priority Programs," Report to the Office of the General Counsel, General Motors Co., Arthur D. Little, Inc., 1972.

L.L. Johnson, "Behaviour of the Firm Under Regulatory Constraint: A Reassessment," Amer. Econ. Rev. Proc., May 1973, 63, 90-97.

D.L. Katz, et al., Handbook of Natural Gas Engineering, New York 1967.

P.W. MacAvoy, "The Effectiveness of the Federal Power Commission," Bell J. Econ., Autumn 1970, 1, 271-303.

____________ and R. Noll, "Relative Prices on Regulated Transactions of the Natural Gas Pipelines," Bell J. Econ., Spring 1973, 4, 213-34.

Moody's Investors Service, Moody's Public Utilities, various issues.

National Petroleium Council, U.S. Petroleum and Gas Transportation Capacities, Washington 1967.

J.P. O'Donnel, "Annual Study of Pipeline Installation and Equipment Costs," Oil and Gas J., various issues.

H.C. Peterson, "An Empirical Test of Regulatory Effects," Bell J. Econ., Spring 1975, 6, 111-26.

T. Robinson, "Powering of Natural Gas Pipelines," J. Eng. Power, A.S.M.E. Trans., July 1972, 94, 181-86.

L. Rosenberg, "Natural Gas Pipeline Rate-Making Problems," unpublished doctoral dissertation, Cornell University, 1963.

R.M. Spann, "Rate of Return Regulation and Efficiency in Production: An Empirical Test of the Averch-Johnson Thesis," Bell J. Econ., Spring 1974, 5, 38-52.

U.S. Department of Interior, Bureau of Mines, Main Line Natural Gas Sales to Industrial Users, Washington 1974.

U.S. Federal Power Commission, "Transmission Task Force Reports," National Gas Survey, 3 vols., Washington 1973.

________, Reports, various issues.

________, Statistics of Interstate Natural Gas Pipeline Companies, various issues.

S.H. Wellisz, "Regulation of Natural Gas Pipeline Companies: An Economic Analysis," J. Polit. Econ., Feb. 1963, 71, 30-43.

E.E. Zajac, "Lagrange Multiplier Values at Constrained Optima," J. Econ. Theory, Apr. 1972, 4, 125-31.

Faculty of Business
McMaster University

WORKING PAPER SERIES

101. Torrance, George W., "A Generalized Cost-effectiveness Model for the Evaluation of Health Programs," November, 1970.

102. Isbester, A. Fraser and Sandra C. Castle, "Teachers and Collective Bargaining in Ontario: A Means to What End?" November, 1971.

103. Thomas, Arthur L., "Transfer Prices of the Multinational Firm: When Will They be Arbitrary?" (Reprinted from: Abacus, Vol. 7, No. 1, June, 1971).

104. Szendrovits, Andrew Z., "An Economic Production Quantity Model with Holding Time and Costs of Work-in-process Inventory," March, 1974.

111. Basu, S., "Investment Performance of Common Stocks in Relation to their Price-earnings Ratios: A Text of the Efficient Market Hypothesis," March, 1975.

112. Truscott, William G., "Some Dynamic Extensions of a Discrete Location-Allocation Problem," March, 1976.

113. Basu, S. and J.R. Hanna, "Accounting for Changes in the General Purchasing Power of Money: The Impact on Financial Statements of Canadian Corporations for the Period 1967-74," April, 1976. (Reprinted from Cost and Management, January-February, 1976).

114. Deal, K.R., "Verification of the Theoretical Consistency of a Differential Game in Advertising," March, 1976.

114a. Deal, K.R. "Optimizing Advertising Expenditures in a Dynamic Duopoly," March, 1976.

115. Adams, Roy J., "The Canada-United States Labour Link Under Stress," [1976].

116. Thomas, Arthur L., "The Extended Approach to Joint-Cost Allocation: Relaxation of Simplifying Assumptions," June, 1976.

117. Adams, Roy J. and C.H. Rummel, "Worker's Participation in Management in West Germany: Impact on the Work, the Enterprise and the Trade Unions," September, 1976.

118. Szendrovits, Andrew Z., "A Comment on 'Optimal and System Myopic Policies for Multi-echelon Production/Inventory Assembly Systems'," [1976].

119. Meadows, Ian S.G., "Organic Structure and Innovation in Small Work Groups," October, 1976.

120. Basu, S., "The Effect of Earnings Yield on Assessments of the Association Between Annual Accounting Income Numbers and Security Prices," October, 1976.

121. Agarwal, Naresh C., "Labour Supply Behaviour of Married Women - A Model with Permanent and Transitory Variables," October, 1976.

122. Meadows, Ian S.G., "Organic Structure, Satisfaction and Personality," October, 1976.

123. Banting, Peter M., "Customer Service in Industrial Marketing: A Comparative Study," October, 1976. (Reprinted from: European Journal of Marketing, Vol. 10, No. 3, Summer, 1976).

124. Aivazian, V., "On the Comparative-Statics of Asset Demand," August, 1976.

125. Aivazian, V., "Contamination by Risk Reconsidered," October, 1976.

126. Szendrovits, Andrew Z. and George O. Wesolowsky, "Variation in Optimizing Serial Multi-Stage Production/Inventory Systems, March 1977.

127. Agarwal, Naresh C., "Size-Structure Relationship: A Further Elaboration," March 1977.

128. Jain, Harish C., "Minority Workers, the Structure of Labour Markets and Anti-Discrimination Legislation," March, 1977.

129. Adams, Roy J., "Employer Solidarity," March, 1977.

130. Gould, Lawrence I. and Stanley N. Laiken, "The Effect of Income Taxation and Investment Priorities: The RRSP," March 1977.

131. Callen, Jeffrey L., "Financial Cost Allocations: A Game-Theoretic Approach," March 1977.

132. Jain, Harish C., "Race and Sex Discrimination Legislation in North America and Britain: Some Lessons for Canada," May, 1977.

133. Hayashi, Kichiro. "Corporate Planning Practices in Japanese Multinationals. Accepted for publication in the Academy of Management Journal in 1978.

134. Jain, Harish C., Neil Hood and Steve Young, "Cross-Cultural Aspects of Personnel Policies in Multi-Nationals: A Case Study of Chrysler UK", June, 1977.

135. Aivazian, V. and J. L. Callen, "Investment, Market Structure and the Cost of Capital", July, 1977.

136. Adams, R. J., "Canadian Industrial Relations and the German Example", October, 1977.