TIMING OF INVESTMENT IN REGULATED NATURAL GAS PIPELINES

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Abstract
We address the optimal timing of investment in regulated natural gas pipelines when the demand for gas is stochastic. We show that this is a problem that can be solved in theory, but the practical solution depends on functions and parameters that are either subjective or cannot be estimated. We then reformulate the problem in a manner that can Pareto rank investment strategies. These strategies can be implemented with reasonably straightforward policies. The demand for gas is very inelastic and thus the welfare losses associated from small deviations from a first best optimum are minimal. This implies that the gas pipeline system can be regulated with a relatively simple set of transparent rules without any significant loss of welfare.

JEL classification L51

Key words: natural gas, regulation, investment, pipeline, stochastic demand.

1. Introduction[*]

It is important that gas is able to move in a pipeline to equilibrate supply and demand. If a pipeline does become congested, there will be excess demand and it becomes impossible to supply the amount of gas that would clear the market. When the pipeline system became congested in the United States in the summer of 2000 there were disruptive peaks in the price of gas, and rents accrued to agents who had access to the pipeline.

Unfortunately, the market is not a good guide to the allocation of resources in pipeline capacity. It can take as long as three years lead time to increase pipeline capacity, so it is

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necessary to rely on forecasts of future demands for the purpose of planning investment in pipeline capacity. These forecasts are at best uncertain.

In this paper we will address the optimal timing of investment in a regulated pipeline system where the demand for gas is stochastic. We will show that this is a problem that can be solved in theory, but the solution depends on functions and parameters that are either subjective or cannot be estimated. We will then reformulate the problem in a manner that can rank investment strategies. These strategies are not optimal in the strict sense of the word, but they can be implemented with reasonably straightforward policies.

The demand for gas might be very inelastic and thus the welfare losses associated from small deviations from a first best optimum are minimal. In particular, this implies that a gas pipeline system could be regulated with a reasonably simple set of rules that promote transportation expansion, and without any significant loss of welfare.[1] The resulting system can be transparent and a good candidate for some institutional arrangement in which there is substantial incremental private investment in gas pipelines.[2]

2. The Production Function for Gas Pipelines

A simplified formula for computing the rate of flow of gas in a pipeline is given by

$$Q = \frac{871 d^{\frac{8}{3}} \sqrt{P_1^2 - P_2^2}}{\sqrt{L}} \tag{1}$$

where:

d = internal diameter of pipe in inches

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[1] For an analysis of regulated pipeline companies in OECD countries with low price elasticity of demand for natural gas see Dahl (1992), Liu (2004), and Nilsen (2004).

[2] Mexico is an example of a gas industry that is owned by a public firm (Pemex) and that has not been successful enough to develop partly, due to the ownership structure but also due to its regulatory framework (see Brito and Rosellón, 2000, 2002, 2003; Brito, Littlejohn and Rosellón, 2003; and Rosellón and Halpern, 2001).

L = length of line in miles

Q = throughput per day

P_1= absolute pressure at starting point

P_2 = absolute pressure at ending point

The amount of power needed to compress a million cubic feet a day is given by

(2) $$Z = \frac{R}{R + RJ}\left(\frac{5.46 + 124 Log(R)}{0.97 - 0.03P}\right)$$

where:

Z = horsepower

R = the compression ratio, absolute discharge pressure divided by absolute suction pressure

J = supercompressibility factor which we assume to be 0.022 per 100 pounds per square inch absolute suction pressure.

Assuming as given the discharge pressure, equation (1) can be used to solve for the necessary pressure as function of the throughput. Equation (2) can then be used to compute the amount of power necessary. We can use these values to compute the cost of transporting gas. The costs are calculated under the assumptions that the real interest rate is 10 percent, the cost of pipeline is $25,000 per mile inch, maintenance costs are assumed to be 3 percent, and the cost of gas to power the pumps is $2.00 per thousand cubic feet (MCF). The cost of an installed horsepower is assumed to be $600 and the project life to be fifteen years.

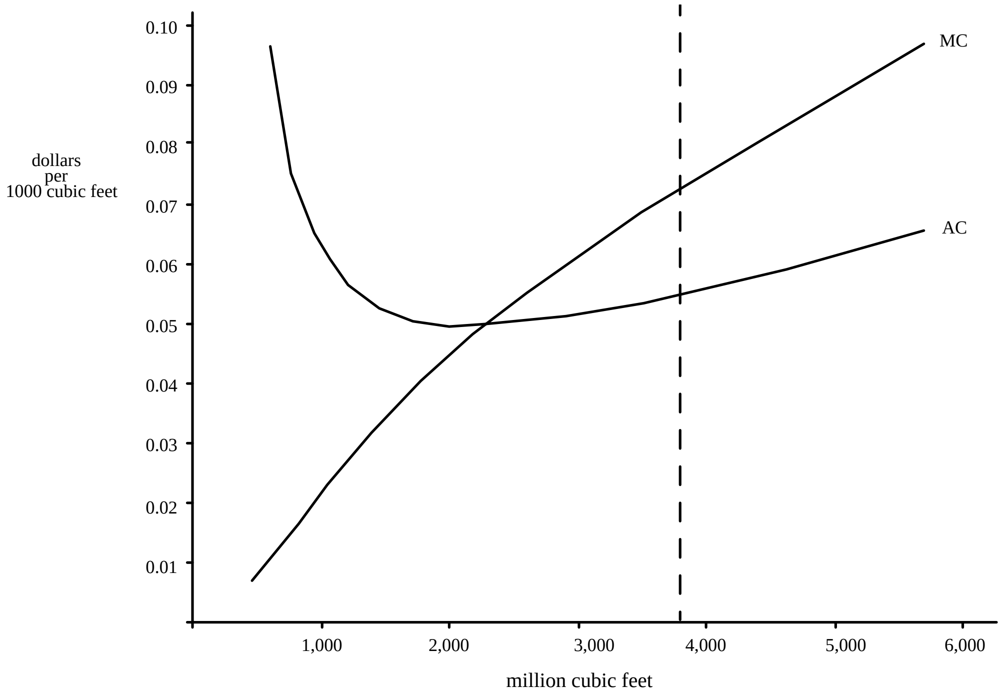

Figure 1

Pipelines have a high fixed cost, and for a substantial portion of their operating region low marginal costs. The capacity of the pipeline is ultimately limited by the pressure limits of pipe. Figure 1 illustrates the cost curves for a 48-inch pipeline 100 miles long. At a pressure limit of 1,500 pounds per square inch, the pipeline reached its limit at approximately 3,800 million cubic feet per day. The dashed line denotes this limit. At this point it becomes impossible to increase throughput by increasing power and it becomes necessary to add compressor stations that increases throughput without exceeding the line limit by increasing the pressure gradient. Note that this formulation leads to a cost of moving 1 MCF of gas 1000 miles to be $.50.

In a regulated regime for a gas network, marginal cost pricing results in a loss. (See Figure 1.) One solution to this problem is to set a fee that yields a regulated rate of return over the life of the project sufficient to cover all costs. An alternative, more sophisticated alternative is a two-part tariff with a price cap. The sophisticated price cap mechanism is efficient in that it sets the marginal cost of transporting gas equal to the variable change for moving gas. The question is whether the more efficient allocation of resources merits the additional difficulties in regulation.

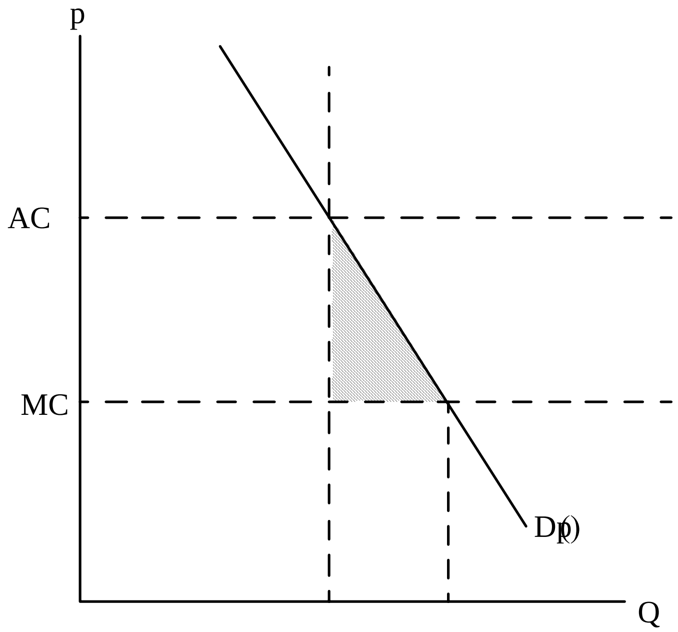

Figure 2

The shaded area in Figure 2 illustrates the welfare loss associated with using average cost rather than marginal cost in transporting gas. The loss, *L*, is given by

(3) $$L = \frac{(AC - MC)^2 Q\eta}{2p}$$

where η is the elasticity of the demand for gas. Simple calculations suggest that for elasticities in the demand for gas in the range of - 0.1 to - 0.2 the welfare loss is of second order and can be ignored. If we calculate the dead weight loss for 4 million MCF the price of gas equal to \$4.00 per MCF, an elasticity for the demand for gas equal to -0.1, and a differential between AC and MC of \$0.02, we get that the deadweight loss is \$20. Since the cost of moving gas is linear with distance, the deadweight loss over a distance of 1000 miles is \$200.

The welfare loss associated with using a rate of return fee structure for transport pipelines is so small that it is hard to see how the additional complexity in regulation can be justified, especially if the elasticity in the demand for gas is low.

3. Timing of Investment in Pipeline Capacity: The General Case

Let us consider the case when gas is being transmitted a distance *L* over a pipeline of diameter *D*. The demand for gas is given by

(4) $$Q(t) = e^{\alpha t} Q_0 D(p)$$

where α is a random variable with mean $\overline{\alpha}$ and *p* is a random variable with mean $\overline{p}$. Some of the stochastic elements are short term such as weather and others are long term that can reflect macroeconomic conditions.

The pressure limit on the pipeline is $\overline{Q}$ and we will define $\overline{T}$ such that $\overline{Q} = e^{\overline{\alpha}\overline{T}} Q_0 D(\overline{p})$ (see figure 3).

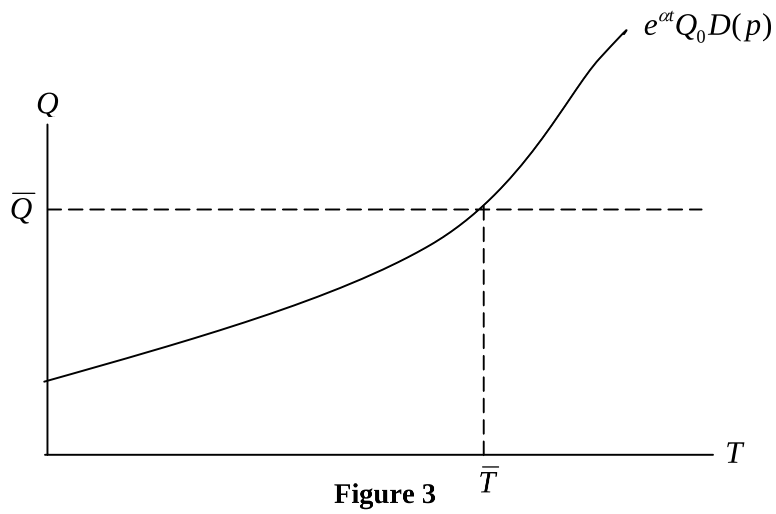

Figure 3

Define $e^{-rT}C(T-t)$ as the cost of building a pipeline at time *t* that will come on line at time *T*.

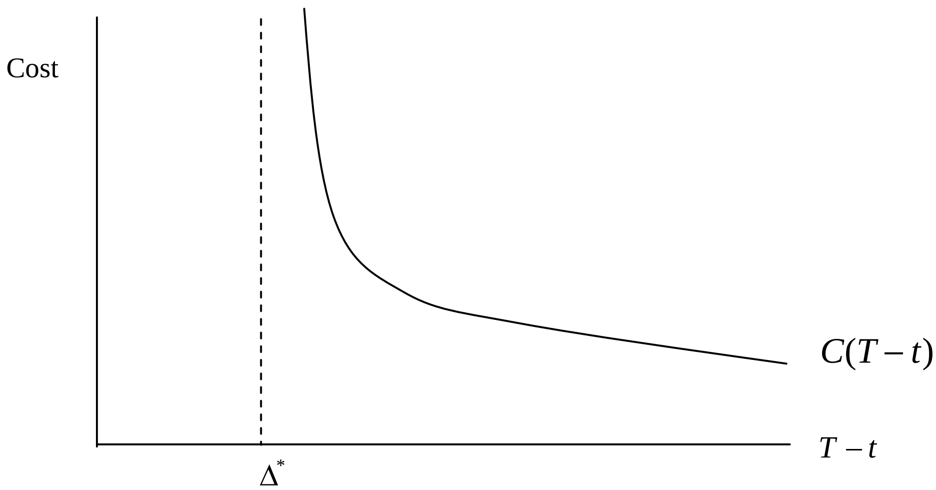

Figure 4

It is assumed that the cost of construction drops as lead time increase, but that there exists some minimum feasible lead time, $T-t=\Delta^*$ (see figure 4).

Define $f[s,Q(t)]$ as the probability at time *t* that $Q(s)=\overline{Q}$ for some $s>t$, given that demand at time *t* is $Q(t)<\overline{Q}$. Define $S(n,s)$ as the consumer surplus lost at time *n* if the constraint becomes binding at time *s*. The welfare loss, $W(s)$, of the constraint binding at time *s* is thus,

(5) $$W(s)=\int_s^T S(n,s)ds$$

and the expected welfare lost at time *t* is:

(6) $$E[W(t)] = \int_t^T f[s, Q(t)] \int_s^T S(n,s)\,dnds$$

If the constraint binds, the price of gas will have to increase as gas cannot move to equilibrate the market (see figure 5).

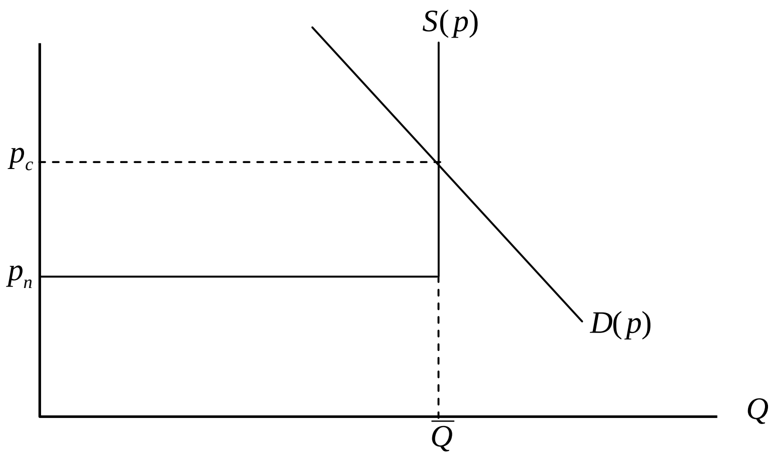

Figure 5

Define $R(s,n)$ as the rents at time n if the constraint becomes binding at time s. Define the total transfer that results from these rents as $Z(s)$. Thus, if the constraint is binding at time s,

(7) $$Z(s) = \int_s^T R(s,n)\,dn$$

and the expected value of transfers at time t is:

(8) $$E[Z(t)] = \int_t^T f[s,Q(t)] \int_s^T R(s,n)dnds$$

These are transfers from the consumers of gas to who ever has access to the existing pipeline capacity. Strictly speaking, these transfers do not represent a loss in welfare. A country could capture such rents by taxation. However, the country could have tax gas and captured such rents in the absence of pipeline congestion. This suggests that in some political or economic calculation (that is more general than the timing of investment in pipelines) it is decided that the benefits from taxing gas were out weighed by other economic or political factors.

Since transfers are such an important component of congestion, the calculation of the optimal timing of pipeline investment should be done in the context of the more general problem. This is not possible, but we can approximate the more general problem by assigning a cost ϕ to the transfers so that the cost of the transfers is given by

(9) $$E[X(t)] = \phi E[Z(t)], \;\; 0 \le \phi \le 1$$

where $\phi = 0$ means that there is no cost to the planner associated with transfers cause by congestion of the pipelines, and $\phi = 1$ means that the interests of the planner and the consumers of gas are identical.

We can then compare the outcome of this maximization with policies that are strictly preferred by consumers of gas to bearing the risk that they will have to pay the transfers caused by congestion. Then, if gas consumers are willing to pay for a level of pipeline capacity that eliminates transfers, then they are better off. Such a policy would not strictly speaking be Pareto superior to a policy that that could result in congestion and transfers as real resources are being devoted to avoiding transfers.

4. Optimal Investment in Pipeline

Let us assume that a regulated pipeline firm is trying to time investment in gas pipelines to minimize a cost function that is the sum of the investment in pipelines, loss of consumer surplus and a weighted sum of the transfers:

(10) $$Y(t) = e^{-rT}C(T-t) + \int_t^T f[s,Q(t)]\int_s^T S(n,s)dnds + \phi \int_t^T f[s,Q(t)]\int_s^T R(s,n)dnds$$

this expression can be written as

(11) $$Y(t) = e^{-rT}C(T-t) + \int_t^T f[s,Q(t)]\int_s^T [S(n,s) + \phi R(s,n)]dnds$$

If we differentiate with respect to *T*, we get

(12) $$\frac{dY(t)}{dT} = e^{-rT}[\frac{\partial C(T-t)}{\partial T} - rC(T-t)] + f[T,Q(t)]\int_T^T [S(n,s) + \phi R(s,n)]dn$$
$$+ \int_t^T f[s,Q(t)][S(t,s) + \phi R(t,n)]ds$$

The term $f[T,Q(t)]\int_T^T [S(n,s) + \phi R(s,n)]dn = 0$ so

(13) $$\frac{dY(t)}{dT} = e^{-rT}[\frac{\partial C(T-t)}{\partial T} - rC(T-t)] + \int_t^T f[s,Q(t)][S(t,s) + \phi R(t,n)]ds$$

and we get the expected result that the target date of completion of the pipeline is when expected marginal benefits are equal to the marginal cost. There are two problems. First, the distribution function on the probability that the constraint will be binding is not well defined and depends on such factors as the performance of the overall economy. Second, the solution depends on the subjective value of the parameter ϕ. The outcome is substantially a function of the choice of ϕ which is subjective.

5. Timing of Investment in Pipeline Capacity: A Heuristic Approach

Let us again consider the case when gas is being transmitted a distance *L* over a pipeline of diameter *D*. The demand for gas is given by

(14) $$Q(t) = e^{\alpha t} Q_0 D(p)$$

where α is a random variable with mean $\overline{\alpha}$ and *p* is a random variable with mean $\overline{p}$. The pressure limit on the pipeline is $\overline{Q}$ and we will define $\overline{T}$ such that $\overline{Q} = e^{\overline{\alpha}\overline{T}} Q_0 D(\overline{p})$. Assume that initial demand is given by $\frac{\overline{Q}}{2}$ so the expected time for the pipeline to reach full capacity is $\bar{t} = \frac{\ln(2)}{\alpha}$. Now let us consider a sequence of investment such that pipeline capacity is doubled every time the pipeline reaches full capacity. Thus there is a sequence of investments at T_i, where $T_i = T_{i-1} + \bar{t}$. Let $c_1(t) = c_{11} + c_{12}(t)$ be the charge for transporting gas. The first term, c_{11} covers fixed costs and the second term $c_{12}(t)$ covers variable costs incurred at time *t*. The present value of the revenues of the pipeline are given by

(15) $$PVR_1 = \sum_{i=0}^{\infty} e^{-ir\bar{t}} \frac{\overline{Q}}{2} \int_0^{\bar{t}} [c_{11} + c_{12}(t)]e^{(\overline{\alpha}-r)s} ds = \frac{\overline{Q}}{2\left(1 - e^{-ir\bar{t}}\right)} \int_0^{\bar{t}} [c_{11} + c_{12}(t)]e^{(\overline{\alpha}-r)s} ds$$

Let $C(\overline{Q})$ be the cost of the investment. The cost of operating the pipeline is the sum of the capital cost plus the cost of operating the pipeline. Present value is given by

(16) $$PVC_1 = \sum_{i=0}^{\infty} e^{-ir\bar{t}} \left[C(\overline{Q}) + \frac{\overline{Q}}{2} \int_0^{\bar{t}} e^{(\overline{\alpha}-r)s} c_{12}(t) ds \right] = \frac{1}{(1 - e^{-r\bar{t}})} \left[C(\overline{Q}) + \frac{\overline{Q}}{2} \int_0^{\bar{t}} e^{(\overline{\alpha}-r)s} c_{12}(t) ds \right]$$

Setting $PVC_1 = PVR_1$ we get,

(17) $$\frac{1}{(1 - e^{-r\bar{t}})} \left[C(\overline{Q}) \right] = \frac{\overline{Q}}{2\left(1 - e^{-ir\bar{t}}\right)} \int_0^{\bar{t}} [c_{11}]e^{(\overline{\alpha}-r)s} ds = \frac{\overline{Q} c_{11}}{2\left(1 - e^{-ir\bar{t}}\right)(\overline{\alpha} - r)} \left(e^{(\overline{\alpha}-r)\bar{t}} - 1 \right)$$

(18) $$c_{11} = \frac{2(\overline{\alpha} - r)}{\left(e^{(\overline{\alpha}-r)\bar{t}} - 1\right)\overline{Q}} \left[C(\overline{Q}) \right]$$

Now consider any other sequence of investment where the capacity of the pipeline is given by $(1+\beta)\overline{Q}$. If we assume that the horsepower/pipe diameter ratio is constant, then from the production function

$$C[(1+\beta)\overline{Q}] = (1+\beta)^{\frac{3}{8}} C(\overline{Q})$$

Let $c_2(t) = c_{21} + c_{22}(t)$ be the charge for transporting gas. Then

(19)
$$\frac{c_{21}}{c_{11}} = (1+\beta)^{\frac{3}{8}}.$$

The difference in the costs can be expressed as a function of c_{11},

(20)
$$c_{21} - c_{11} = \left((1+\beta)^{\frac{3}{8}} - 1\right)c_{11}.$$

The cost per thousand cubic feet of gas transported for maintaining a β percent buffer of excess capacity, ΔC, is given by substituting into equations (19) and (20).

(20')
$$\Delta C = \int_0^{\bar{t}} e^{-rt}\left((1+\beta)^{\frac{3}{8}} - 1\right)c_{11}dt = \frac{1}{r}\left((1+\beta)^{\frac{3}{8}} - 1\right)c_{11}(1 - e^{-r\tilde{t}})$$

Let us calculate a simple example assuming that $r = .12$ and $\overline{\alpha} = .06$, and that the cost without a buffer is \$.25 per 1000 cubic feet. If there is no buffer, then at a growth rate of six percent a year, $\bar{t} = 11.5$. Table 1 below gives the cost per MCF of maintaining excess buffer capacity.

Cost per Year of Pipeline Buffer Capacity		
Years	Change in Tariff dollars	Present Value of Cost dollars
1	.006	12.98
2	.012	26.25
3	.017	39.82
4	.024	53.70
5	.030	67.90

Table 1

Now consider a consumer that purchases an amount of gas Q_1 over the period $(0,\bar{t})$. The consumer faces two alternatives: First, the consumer can pay a transport charge c_1 and not run the risk that the pipeline will be congested; or second the consumer can run the risk that the pipeline will become congested.

Suppose that it is possible to create a market mechanism to allocate gas if the pipeline becomes congested. This is a lower bound of the expected cost. The increase is price is given by

(21) $$\Delta p = \frac{p}{\eta}\frac{\Delta Q}{\overline{Q}},$$

for the period during which the pipeline is congested. Let $g(t)$ be the probability that the pipeline will be congested at time *t*. The present value of the expected rents the consumer will pay over the planning period is:

(22) $$E[Z(t)] = \int_0^T g(t)e^{-rt}\frac{p}{\eta}\frac{\Delta Q}{\overline{Q}}dt.$$

Note that there are three random elements in this expression, the gas price, *p*, at the time of congestion, the percentage of above full capacity, $\frac{\Delta Q}{\overline{Q}}$, and the probability that the pipeline will be congested. Of these random variables, the gas price is the only one for which there exists published forecasts and, as we have seen in the past year, these forecasts are not very accurate.

Since the factors that define the cost of congestion are not well defined and hard to understand as abstract concepts it is useful to define a new variable which is intuitive. We will define a standard expected congestion day as 24 hours during which the price of gas goes up by 1 dollar with a probability of one. Thus, one day where the price of gas goes up by one dollar with probability one and one day where the price of gas goes up by two dollarss with probability one half are both one standard expected congestion day. Understanding this concept intuitively does not require understanding the underlying mathematics, and thus it is reasonable to expect consumers of gas to have preferences between standard expected congestion days and the cost of moving gas. Equation (22) can be written as

$$E[Z(t)] = \int_0^T g(t)e^{-rt}\frac{p}{\eta}\frac{\Delta Q}{\bar{Q}}dt = \int_0^T e^{-rt}\theta(t)dt. \tag{23}$$

And within an investment cycle $[0,\bar{t}]$ the cost of congestion is:

$$\int_0^{\bar{t}} e^{-rt}\theta(t)dt > e^{-r\bar{t}}\int_0^{\bar{t}}\theta(t)dt = e^{-r\bar{t}}\hat{\theta} \tag{24}$$

Since we are evaluating the integral at the end point, $\bar{t}$, the expression $e^{-r\bar{t}}\hat{\theta}$ is a lower bound of the expected cost of congestion to the consumer within an investment cycle $[0,\bar{t}]$. Thus, we can express a lower bound of the tradeoff for consumers between buffer capacity to the pipeline and a standard expected congestion days:

$$e^{-r\bar{t}}\hat{\theta} = \frac{1}{r}\left((1+\beta)^{\frac{3}{8}} - 1\right)c_{11}(1-e^{-r\bar{t}}), \tag{25}$$

which can be solved for $\hat{\theta}$.

$$\hat{\theta} = \frac{e^{r\bar{t}}}{r}\left((1+\beta)^{\frac{3}{8}} - 1\right)c_{11}(1 - e^{-r\bar{t}}) \tag{26}$$

It is possible to examine the relationship between standard expected congestion days and the desired amount of buffer for the parameters of the problem.

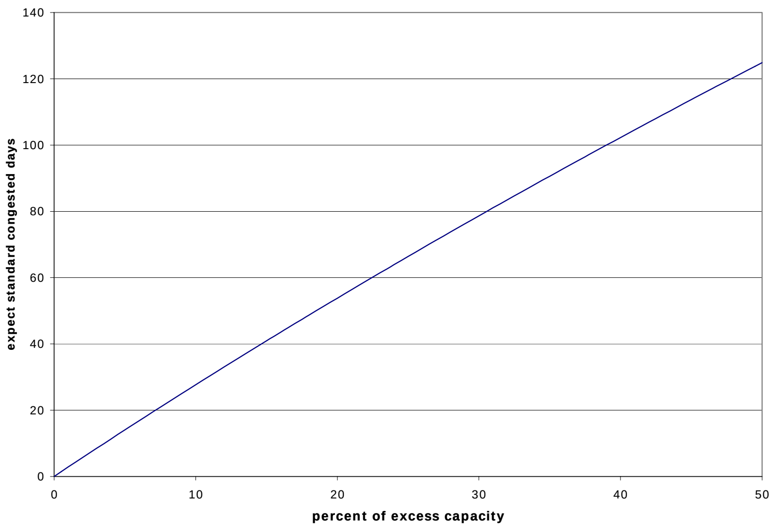

Figure 6

From Figure 6 it is clear that the consumer is willing to pay the cost of 20 percent excess capacity to avoid approximately 50 days of congestion. At 6 percent growth rate for the demand for gas, this translates into more that three years of excess capacity. The congestion can result form many causes including weather, economic factors and failure to invest in sufficient capacity. To get an intuitive sense for this variable let us consider the case where the congestion is caused by the failure to complete the pipeline on schedule.

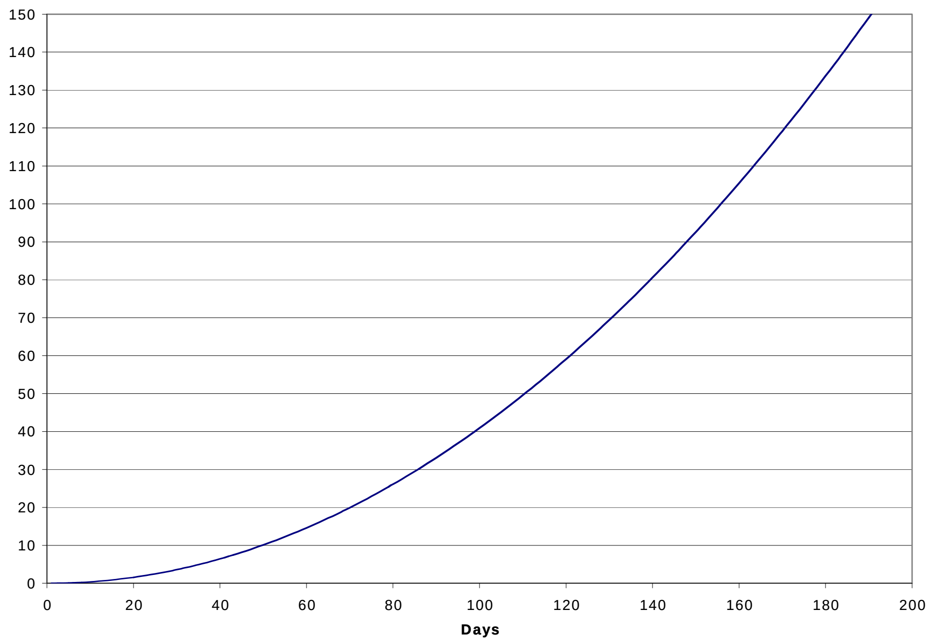

Figure 7

If we examine Figure 7, we see that the consumer would experience 50 expected congestion days in less than 120 days. This is equivalent to just over 2 percent excess capacity, so the consumer would be willing to pay for 20 percent excess capacity to avoid the cost of the loss that could be avoided by just over 2 percent excess capacity. The` reason for this is that congestion results in transfers. Although it may not be efficient in the technical sense of the word, consumers of gas would rather pay for excess capacity than run the risk of paying the transfers

6. Conclusions

When demand for gas is very inelastic it becomes a two edged sword with respect to ppipeline capacity in a regulated regime. An increase in demand would result in huge increase in the price that would clear the market if gas is not free to flow. However, when demand is so inelastic it permits the implementation of a very simple rate structure and appears to justify investment in substantial buffer capacity. Calculations suggest that users would prefer to pay for excess capacity in the pipeline system than to risk the consequences of congestion. This appears to be contrary to the usual result in network economics that it is optimal to have some congestion. Consumers of gas are willing to pay to avoid transfers. In as much as the regulatory authorities view their charge as serving the users of the pipeline, than a simple rate structure that insures adequate capacity will serve the needs of the consumers of gas.

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