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MASTER

**FUNDAMENTAL ECONOMIC ISSUES IN THE
DEVELOPMENT OF SMALL SCALE HYDRO**

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INTRODUCTION

This paper will raise and, in part, address some basic economic issues involved in the development of Small Scale Hydroelectric power (SSH). The analysis that follows is based on literature reviews, reviews of some case studies of SSH projects, on-site visits and continual discussion with the members of the Franklin Pierce - Thayer project and others working in the area. Broadly stated, economic analysis to date strongly suggests that the answers to the problems of the present slow rate of development of SSH projects are found in law books and regulatory codes and not in engineering manuals. Further analysis must be performed and additional data collected before the suggestion that legal and regulatory constraints are the major obstacle to SSH development becomes a conclusion.

One of the guidelines that any academic economist must learn to live by if he or she wishes to take himself or herself seriously is that when studying the profitability of various investments, if the investment appears profitable, the study has some error. It is most improbable for anyone to discover a profitable, yet untapped, area from the resources of an academic economist. (One exception to this might be the area of bond purchases where economists, as a group, seem to do quite well.) By the time an economist has determined an area of investment should reap substantial rewards, someone has so reaped. However, if the economist's inquiry is not particularly useful in helping the person on the street make his/her first million (or should we say ten million), it can be quite useful in providing an understanding of areas which have "normal profit" or areas which appear to be unprofitable. In this line, the following discussion of small scale hydroelectric projects represents an economist's view of the investment

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process in this resource.

After a cursory study of the field it is apparent that many people and institutions are interested in developing small scale hydro. Yet, with all this interest there is not a great deal of money spent on the actual construction. In fact, in the northeast quadrant of the country there have been less than a handful of sites under 5 MW capacity put into operation in the last ten (10) years. Small hydro is clearly not the hottest investment project since semi-conductors, or at least it may be claimed that small hydro is not an investment on which many people are willing to gamble large portions of their own net worth. What this discussion will attempt to show is that the reason for this may not be that the expected present worth of the returns of the project do not exceed the construction cost by a sufficient amount. Rather, a set of factors in combination impose costs on the project not normally incurred in small businesses.

The discussion is broken down into four (4) parts: costs, supply, demand and profitability. The analysis is addressed toward presenting the economic picture of a hydro site as if it were a typical small business from which conclusions may be drawn as to causes.

I. Costs

It is the obvious goal of a discussion of cost to explain what the costs of the output of a process are. For instance, what does it cost to carry a passenger, by highway, from town A to town B? In this example the answer depends on the number of passengers per trip and the number of trips during the life of the vehicle, along with the apparent questions of the cost of the vehicle and the cost of making a trip. The question of cost of electricity from small hydroelectric generation has similar if not identical problems. In determining the cost of highway transportation, we need not know how an internal combustion engine operates, but it is vital to know the size of the vehicle. The discussion of costs will thus start with the size characteristics of hydroelectric generation.

Water flows from one level (the headwater) to a lower level (the tailwater), through the power equipment and is converted from water pressure into mechanical energy (through the turbine), then into electrical energy (through the generator). The amount of water (the flow in cubic feet per second) over the year and the difference between the headwater and the tailwater (the gross head or head in this discussion) determine the total energy of the site. The total energy has two characteristics. The First is the capacity at an instant given in kilowatts (KW). The second is the total energy over the year given in kilowatt hours (KWH). Clearly changes in the dam can change the head and

instantaneous flow which will affect the power potential of a site. The benefits from the amount of power and the ability to offer a larger proportion at particular times, are part of the decision economists label as plant size determination. Since the area of study is largely that of the existing dam, the size of the hydro facility will be considered as given.* Similarly, the cost of repairing the dam and its associated structures will be taken as given. What this amounts to is a cost which can be less than \$100/KW to well over \$500/KW of capacity. This difference obviously affects the profitability of a site. The problem is that without site surveys there is no good method of estimating their value. Therefore, cost data for sites must have a range of, say \$500/KW for differences in site conditions. This assumes that sites in gross disrepair are not under consideration. The site is now characterized by a flow, a head, the resultant capacity, and a dollar figure for improvement in the dam, penstock and other structures. That dollar figure will heroically be called \$400/KW. This data dictates the power equipment.

The question of costs of the power equipment is considerably easier, but is still subject to the site characteristics. Consider the following two sites each with a 1000 KW capacity. One has a

* Even for existing dams this is not quite true. Changes in the penstock (the passageway for water to the turbine) and design of the draft tube (the passage from the turbine) can change the head. These procedures are well known and will be utilized when the costs versus the additional revenues require such procedures.

12 foot head and a 1350 cubic ft. per second flow. The other has a 32 foot head and a 500 cubic ft. per second flow. The equipment for the first costs approximately 1,000,000; the equipment for the second costs approximately \$500,000. This is a cost of \$1,000/KW versus \$500/KW or a \$500/KW difference in equipment cost. What this example illustrates is that within a class of equipment the total cost is basically a direct function of the water flow. There are relatively small changes in total cost from changes in the head for a given flow. The above example might be considered a typical difference due to the site characteristics. The potential magnitude of site differences in the cost of generation can be seen by taking the extremes for standardized units. (Units over 5000 KW are usually site designed since the efficiency gains from the larger sites more than pay for the added cost of manufacture.) A 5000 KW site with a 50 foot head will cost slightly less than \$300/KW for the power equipment. A 50 KW site with a 10 foot head will cost about \$5000/KW for the smallest standardized package. (This is approximately the cost of electric power from solar cells.) This is over a factor of 15 in cost per KW of installed capacity. However, this is due to both head and flow variation. As a rough rule, the cost per KW of capacity is inversely proportional to the head height, all other things being equal. Equally rough, cost per KW of capacity per KW of capacity is inversely proportional to the square root of the flow. These considerations are just a cost approximation of power conversion rules applied to power equipment cost estimates. They are explicitly mentioned here to emphasize the site differences in cost, and these differences will not be summarized as being in the \$500 to \$1500 range per KW of installed capacity for the sites under consideration.

After noting the problems of assessing the cost per KW of capacity from the describable site characteristics, it should be pointed out that there still remains variation in the cost of generation equipment installed. Aside from such obvious costs as transportation and installation, the private developer in theory at least, may be able to repair, cannibalize, and adapt used equipment to the site. Peter Burno, a small developer in Wisconsin, who is a member of this study's advisory committee, has demonstrated that he can halve the costs of purchased equipment in the retrofitting of two (2) low head dams. It should be noted that he is accomplishing this while building the plant for a fifty (50) year or longer lifecycle. For various pieces of equipment the cost differences could run as high as a factor of 10. The extent that this would be done if there were a large number of starts of hydro projects is unknown, but the on-site fabrication would imply serious cost over-estimates for those sites where it occurred.

It may be more convenient to view the costs in terms of average long run costs per KWH. Annualizing the fixed costs and then converting them into dollars per KWH necessitates assumptions about the number of hours of generation over the year for the site, the life of the site, and the discount rate. The life of the site will be considered to be twenty-five (25) years exclusive of the three (3) year building period. Costs will be given for sites with a 25% capacity factor (2190 hours) and a 50% capacity factor (4380 hours). The discount rate, which is the appropriate interest rate used for converting present to future values or vice versa, will be within 5% or 10% in real terms (all figures will have inflation netted out). And finally, the range of cost per KW will be \$1000 to \$2000.

<u>COST PER KW OF CAPACITY</u>	<u>CAPACITY FACTOR</u>	<u>DISCOUNT RATE</u>	<u>BREAKEVEN PRICE</u>
		10%	12.2 cents
	25%		
		5%	7.1 cents
\$2000/KW		10%	6.1 cents
	50%		
		5%	3.6 cents
		10%	6.1 cents
	25%		
		5%	3.6 cents
\$1000/KW		10%	3.0 cents
	50%		
		5%	1.3 cents *

* Derivation for last line is: $\$1000/\text{KW} = \sum_{t=3}^{28} \frac{4380 \times \$.018}{(1 + .05)^t}$

The site differences given here produce cost differences per KWH of a factor of 3. The financial consideration increases the factor to almost 7. There is good reason to believe that many of the potential sites' parameters are encompassed by these data. Accordingly, looking at only physical repair, construction costs and returns to the developer (discount factors), many SSH sites can now produce electricity which is economically feasible.

The last section on cost deals with those costs which might be considered as partially overhead or administrative plus financial. These are the costs associated with consultants, lawyers, engineers and lenders. Surveys of the engineering and economic feasibility of a 15 MW site can run \$50,000. An environmental impact statement, if needed, would cost in the hundreds of thousands

of dollars. Legal costs can similarly become quite noticeable for particular projects. Much of the total legal cost is associated with the federal licensing process, and a few private developers have escaped these costs by ignoring the Federal Energy Regulatory Commission (FERC). These costs are not particularly well correlated with size, and they may be viewed as a fixed sum, dependent on site characteristics other than size. This implies the obvious average overhead cost reduction as size increases. To better understand the importance of the initial overhead costs, a sketch of the financial picture of the project must be examined.

For simplicity, the following analysis will be based on one (1) KW of capacity which will be assumed to cost \$1500 to build, the cost per KW of dam repair, structures, and power equipment. If the \$1500 is borrowed at 10% three (3) years before operation, the site will have to return about \$200/year over the life of the project, which is taken as twenty (20) years, for the project to break even. (What determines the revenues is discussed in the next section.) If the interest rate were 11%, the project would have to return about \$20/year more, which is equivalent to a \$140 increase in cost at 10%. Thus, the changes in the interest rate paid on the project can be converted by standard present value calculation into dollars per KW. However, this does not capture one of the important traits of a hydro project as developed by a private owner. This trait is that the hydro investment is a highly leveraged financial asset. If the site being considered were 500 KW in capacity, the total building cost would be \$750,000. This sum will be borrowed. If the overhead costs of the project including the imputed value of the developer's time is \$100,000, this will be assumed to come out of the developer's net worth. It is this sum which the developer could invest elsewhere. If the return from the project is \$130,000/year or (\$260/KW/year) with an interest rate of 10%, the return on the developer's

investment is \$70,000, or 70%. However, if there is a \$50,000 increase in overhead costs, the return is 20%. While the overall return on the project may not have changed much from a \$50,000 increase in expenses, the return to the investor has, and another financial asset may be preferred. (A 20% return would probably be considered insufficient given the sensitivity of this return to small changes in total costs or revenues.) The problem of high debt/equity ratio (the investor's contribution may be considered as equity) of a hydro project applies to small private developers and municipalities who are considering development. These considerations do not apply to the investor-owned utility (I.O.U.) since they are apparently hesitant to change radically historical debt/equity ratios on new investments because of anticipated subsequent reduction in stock prices. This difference potentially implies that small private developers are more likely to undertake projects with lower over-all returns given a low overhead cost/total cost ratio than I.O.U.'s who would look at the overall return on investment.

II. Supply Analysis

While the cost figures given above have use in assessing the position of SSH today relative to other generation techniques, even in a more refined form it is not the tool that is needed for policy analysis. Rather, the required tool is the supply curve of electricity from SSH. A supply curve is a relationship between the price of the output and the quantity of that output that would be forthcoming if that price were in fact offered. The underlying relationship is between the cost of producing an additional unit and the quantity produced when that cost is incurred. The cost includes a normal return on all capital, including the developer's time, used in production. What the supply curve can show is how much additional output is expected for a given increase in price. The relevant supply relationship for the study of the

development of SSH is the long run supply curve. Long run refers to the fact that the time period is sufficiently long to include the development of new sites.

Consider the example previously cited of a 500 KW site with a \$750,000 construction cost and a \$150,000 overhead (the operating and maintenance costs are assumed to be zero, but could easily be netted from the revenues). The developer will be assumed to require a 50% total return on his investment which will be accounted in present value. The debt holders will require a 10% return and further discounting will be ignored. Suppose this site produced 3500 KWH/year per KW of capacity and the output was sold at a uniform price. This project would then be initiated if the price of electricity to the site were 7.5 cents/KWH. That is, as the price of electricity crossed the 7.5 cent mark, there would be an increase in output from SSH due to just this plant to 1750 MWH, the yearly output of the plant.

Ideally, the supply curve would be derived from the aggregation of the data from each site, but this is presently impractical. One method of overcoming this problem is to construct a cost function for a hydro site utilizing the well understood physical properties of hydroelectric generation. It is exactly those properties which produced the cost to head and cost to flow relationship that were noted earlier. The site capacity is proportional to the product of the head times the flow. The total energy available is proportional to the yearly flow. A theoretical supply curve can then be constructed from the physical properties and cost of manufacture* for the power conversion segment of costs. The procedure may then be extended to the remaining electrical costs, dam and structural costs, and the general overhead costs. The result of this process is the supply curve for a hypothetical site dependent on the head

and flow duration at that site. While the estimated breakeven value for the price of electricity at any site may diverge considerably from the actual value, the supply curve formula is meant for a large number of sites. Since the head and flow information from potential sites may be obtained relatively easily, the supply function can be applied to a list of sites, to derive the aggregate supply curve for that list. Over that list the site differences which cannot be explained by head or flow will be averaged, and thus minimize the supply prediction errors. The potential magnitude of these errors can be estimated by applying the supply function to a small list whose site costs are known. Robert Taylor, a physicist at Johns Hopkins Applied Physics Laboratories, is presently doing exactly this. The form of the supply curve has been derived and he is currently working on the problem of its fit for a large list.

With the same objective in mind, Franklin Pierce Law Center is acquiring a data base to undertake what could be called a statistical supply curve of hydroelectric power. The properties of the sale of electricity greatly simplify the statistical problem of identifying a supply curve in the hydroelectric case. The reason for this approach is that several questions may be addressed for which the preceding approach is not suited. Particularly, the question is how fast can cost be expected to rise as a larger percent of the total potential is developed. An investment schedule for hydroelectric projects (small or large) would list the most profitable first and continue

*These costs can be reasonably well estimated. In the turbine-generator construction the price is approximately proportional to the weight, which is a function of the site variables head and flow.

by order of decreasing profitability. The breakeven price per KWH should be rising as one proceeds down the list, and naturally development would be basically at the bottom of the list. One of the advantages of a statistical supply curve is that it may identify the trend of cost increases per KWH which trend was not a function of head or flow. The question to be answered by identification of this trend is, are there reasons to expect increases in cost at the remaining sites from variables other than head, flow, etc.? The statistical supply function is much more useful in answering certain questions than it is as a tool for projection. (Examples would be: are there cost differences associated with type of developer, time of construction other than what can be explained through price changes, etc.?)

The importance of having some workable idea of a supply curve bears re-emphasis. Surveys such as the New England River Basins Commissions can give some limits to the hydro potential of New England. The survey, per se, cannot (nor was it intended) to provide an energy scenario through SSH. However, in combination with a supply function, a tool exists to make meaningful estimates of the development of this resource under alternative policy options.

III. Demand

Ultimately, the demand for hydroelectric power from any hydro facility is derived from the demand for electricity by final consumer. However, electricity consumers do not demand hydroelectric power, per se, which is the issue here. Hydro power is an input in the final product of electricity, and the demand for hydro is considered as a derived demand. Factors which determine this demand include the final demand for electricity, the costs of alternative methods of generation, and the degree of substitutability of hydro power for other forms. Since the substitutability of one form of electricity generation for another (with respect to the output) is basically perfect, the problem of determining the demand curve is greatly simplified. The institutional factors affecting the final demand for electricity also greatly simplify the task. The price for electricity is fixed for the relevant market period, and for all practical considerations there is a sufficient quantity (derived from the generating and carrying capacities of the system) available for all quantities demanded at the set price. (This value of capacity is dealt with as a separate issue.) Therefore, the electricity produced by a hydro site coming on line does not go to some new customer (or old customer demanding more), but is used to replace electricity that could have been generated elsewhere within the supply system. This implies that the value of that electricity is just the cost of the electricity it replaces. This is independent of the final price of electricity so long as the cost conditions of the remaining supply system do not change. The way the final demand affects the price paid to hydro is through the responding (to demand changes) changes in the cost of generation of the supply system. If a seller of electricity is generating electricity at 3 cents per KWH, it is certainly profitable for

him to purchase electricity from a hydro unit at any price below 3 cents. This is so whether the electricity is sold at 7 cents per KWH or 2 cents per KWH. Since he must supply the electricity, the cost differential either increases the profit of the unit or decreases the loss. The demand for hydroelectricity would be extremely simple if all electricity were generated at the same cost. It would be that value for all units up to the last unit sold, at which point the value would fall to zero. However, electricity is generated under different running costs, depending primarily at what time of day it is produced. The reason for this is that the demand for electricity over daily and annual cycles varies in quantity. By utilizing the different generating techniques, which have varying ratios of running to capacity costs per unit of output, the total cost of generation for a given demand load curve may be minimized. Basically, this minimization process entails utility peak units with low capacity cost relative to their fuel costs for satisfying the short period of large quantity demand, and base units with low fuel cost/capacity cost ratio for the long period of essentially constant demand. (There are, of course, gradations in the process which will be lumped under the heading of intermediate.) Since the value of energy generated from hydroelectric projects is dependent on the cost of energy it replaces, essentially the fuel costs, it will be dependent on the time of day (and year) it is delivered. A unit producing 24 hours a day would have blocks of energy each with different values. Given the load curve for the buyer, the demand load schedule for the 24 hour a day unit is a simple transformation. Suppose the annual load curve consisted of 1000 peak generation hours, 3000 intermediate generation hours, and 8760 base generation hours, where the costs are 4 cents, 2 cents, and 1 cent per KWH respectively. The value of the continuous 1 KW generation

would be $1000 \times \$0.04 + 2000 \times \$0.02 + 5760 \times \$0.01$ or \$137.60. What has been described above is the basic principle of the allocation of hydro within a power pool's dispatching routine.

Previously, it was shown that the demand for hydro was independent of the final demand price. This would be true if there were only one cost of generation. Since there are several costs, the percent of time each of these costs occurs affects the shape of the demand for hydro, although each part associated with a given fuel cost receives the same value. The change in the shape will thus affect the total value. For example, if the previously listed periods were 500, 1500 and 6760, the total value would be \$117.60, using the same running costs as listed above. The reason this point is mentioned is that changes in the retail and wholesale rate structures to marginal cost (or peak load - time of day) pricing in an attempt to level the load may accomplish something similar to the given example. However, it is not altogether clear what the result of rate structure reform will be, since the question with respect to the demand for hydro is not the height of the peak (how many KW at system peak), but, rather the length of time the peaking unit is operating. This question has to do with the similarities in the shapes of the supply load (generating costs ratios) and demand load (the number of hours a KW level is included) curves. At this stage, it would be reasonable to predict that marginal cost pricing will decrease the demand for hydro, but whether the shift will be by more than one mill per KWH is unknown.

An area that may be considerably more difficult to resolve in practice is that of what shall be the capacity credit for SSH in regulated transactions. One need not worry about the I.O.U.'s internal allocation of capacity credits, since profitability considerations will produce efficient pricing. The problem

of externalizing such a procedure is not yet an elementary task. A unit should be considered as having capacity (or demand) value if it is available to fill the system's peak. Many hydro units have a relatively low probability of satisfying such a peak, especially if that peak occurs in summer. The probability is basically a function of the stream flow. The crucial point is that the probability is positive. Therefore, the site makes a positive probabilistic contribution which is all any generation unit can do since none are perfectly reliable. The probability of a unit being on line clearly should affect its value as capacity. (A unit with an .80 probability is worth more than one with a .40 probability, in fact, about 3.15 times the value.) However, this is not to say that a unit should receive no credit for having a probability less than one-half or so.

This price or value determination is a problem for public debate for several reasons. One is that the purchaser of the capacity may have considerable market power and can extract all the payment for scarcity due to the unit. Two, is that the good, reliability, produced by private firms is considered as legitimately contributing to electric costs, yet does not have a market by which consumers may vote with the dollars. Three, is that recent economic articles have shown that with respect to the reliability-capacity pricing problem there may exist several allocatively efficient solutions whose only difference is in the question of who gets what share. Each of these is a failure of the market system associated with electricity to allocate resources in a manner of a purely competitive market. Economists, lawyers, and this country's history argue that these problems must be resolved politically.

A caveat must be entered with respect to the demand curve for hydro power when the buyer, assumed to be an investor owned utility, has monopsony (single buyer) power. The monopsonist considers the cost of purchasing as it faces the entire supply curve, not just a single firm. If the monopsonist can not price discriminate, the marginal cost of purchasing the last unit, when all units are paid this price, is greater than the price paid this unit. The monopsonist will purchase power from the suppliers until the marginal cost of this last unit (these costs being calculated incrementally) is equal to the value on the demand curve previously discussed. This implies the price paid to the hydro unit will be less than the cost of generation that is replaced. Hence, less hydro (or any other form of generation facing a monopsonist) will be developed. This is the classical monopoly restriction on the buying side, and it has the associated loss to society from the misallocation (referred to as the deadweight loss). This is somewhat mitigated in the case of SSH, since the sites which are unprofitable to the small developer selling to the I.O.U. can still be profitable for the I.O.U. to develop. Thus, it would be expected that as the marketing dominance of an I.O.U. increased, it would own an increasingly larger share of the small generation facilities. To the extent that the small developer is considered an instrument in the development of energy resources, the monopsony question should be addressed.

The demand section should be concluded with the following summary. Despite the caveat and qualification, it remains clear that the demand for hydro, and hence its value, is tied to the price of fuel (oil in particular) used in the alternative generation. When the price of oil rises,

relative to other goods, the value of hydro power so rises. This relationship will hold as long as there is fuel burning generation to replace. With the present costs for fuel of peaking near 5 cents and base near 2 cents (the most expensive unit sets the value) a comparison may be made with KWH costs of the hypothetical hydro plants in the cost section to see where hydro presently stands.

IV. Profitability

Since the early 1950's the installed hydro capacity of New England has remained virtually unchanged, while the country's capacity has more than doubled. This indicates that the undeveloped sites in New England were not profitable to potential developers during the period from 1950 to 1974. The technology describing hydroelectric power generation has changed little since 1920, thus the profitability of the hydro site is a function of just the relative prices of the input to the output. The two major inputs in a hydro site are the construction of the dam, its structures, and the power house and generation machinery. It is assumed that the former is tied to a general index of fixed structures and the latter can be approximated by a wholesale index on metals.* For the output price, a general fuel wholesale index can be used as an approximation of the price of the output to the developer. With these three price indices, a comparison can be made of hydro development at various periods in its history. Three points are of particular interest. The first is the 1920's when New England's hydro capacity was growing rapidly, thus a period of profitability associated with hydro. The second is the 1950's when the development of the resource was near nil. And the third is now, the period under study.

In 1929 the relative price of fuel to metals was about 1.5 to 1, and fuel relative to structures was about 1.8 to 1. In 1955, the relative price of fuel to metals was about 1.1 to 1, and fuel to structures was 1.30 to 1. Since 1929, there has been a significant decrease in the value of hydro relative to its inputs, and it is easy to see why the development was next

*The latter index should be reasonably good since machinery prices follow very closely to metal prices.

to nothing in the 50's and 60's. (The structures that were being built elsewhere in the country were either subsidized or had absolute advantages sufficient to overcome the relative price disadvantages.) In 1976, the relative price of fuel to metals was 1.35 to 1, and fuel to structure was 1.40 to 1. The values were not quite back to the 1929 relative prices, but close. By the end of 1977 the fuel/metals price ratio was just over 1.5 to 1. While the numbers for the end of 1978 were not available at FPLC at this writing, it may be assumed that the trend has continued and will continue through 1979. The fuel structures ratio in 1977 was about 1.4 to 1 indicating structures will remain relatively more expensive than they were in 1929 relative to fuel for several years. However, recalling the average cost data, this price is about half as important as the metals price for the retrofitting of existing sites. Before drawing the apparent conclusion, it should be noted that there is no mention of the gains in efficiency in fossil fuel electric generation. This is partially due to the fact that the fuel index, which includes electric prices, partially incorporates the gain and partially is due to the problem of estimating the residual that was not incorporated in the aggregate index. From 1930 to 1960 the nation-wide average in fuel savings per KWH was approximately 40%. Assuming approximately 25% of this is explained in the fuel and power price index, the effective fuel/metals price index for 1960 would be .73 to 1. The question of what is the fuel (metal price ratio for 1977) depends on the type of fuel. With petroleum, it is around 1.2 to 1. The problem with using petroleum is that the price is kept below the market price through regulation. Using coal, the ratio is about 1.35 to 1. When the increases in the relative prices of fuel and the decrease in fuel efficiency since 1960 are accounted for,

the statement that the relative price of the value of hydro power to the cost of production today is approximately what it was during the years hydro was rapidly growing appears valid.

If the price of the output has risen relative to the input, an increase in output would be expected. If none is observed, it would be concluded that either the technology has changed or a factor of production, contributing to costs, has been ignored. Since there are many assurances that the technology is basically fixed, the search is for the factor contributing to costs. There is good reason to believe that it is regulation. There are few goods whose price increases can match the fuel price increases of the last ten (10) years. There are none which are known to be an input in hydroelectric development. However, as a service, the relative price of regulation may have risen sufficiently fast such that the associated costs may have negated the revenue increases from fuel price increases. If regulatory costs are roughly proportional to number of regulating employees dispensing regulation, there have been dramatic increases in the regulatory costs of hydro power.

One important economic consideration has so far been ignored (it is hoped at FPLC that there have not been many others). This is the price of the site. By site it is meant the right to develop the site. It has been previously shown that there is reason to believe that there are large numbers of hydro sites which are close to the breakeven cost using today's prices. The net present worth is close enough to zero that the question of exactly how many requires the actual site information. However, the revenues to be received by these sites (if they are paid the marginal value of their output) most likely will not remain constant. Since the beginning of

1973 to the beginning of 1978, fuel prices have risen at over 24% annually, compared to a 9.5% increase in the price of all goods, i.e., a 14.5% annual increase in the relative price of fuel. Whether this trend increases, decreases, or remains constant, there will be speculators who believe in the extremes. That is, there are financial investors whose purchases imply a bet that fuel prices will increase by over 8% relative to other goods. To see this in practice, one may check the capital gains of energy stocks, noting that these gains represent some sort of average view. Small scale hydro is an "over the table" energy stock; one whose gains are not readily apparent. Have the high priced energy speculators been bidding up the price of hydro sites? Has FERC been deluged with applications for sites? Basically they have not. Hydro is an energy future analogous to a wheat or corn future. However, the latter has a well organized and very competitive market with well understood rules. Hydro does not. An 8 to 10% annual increase in the relative price of fuel would make a large number of sites very profitable. Yet, something in the nature of the investment in hydro makes investors who believe in such large increases or who wish to hedge their portfolios from the large increases shy away from this investment. It is very reasonable to believe the restraint is the regulatory cost imposed on a project with a very long payback period. For this case, the form of the costs may be inferred. Site ownership, per se, could incur a cost (for instance, dam liability) separate from construction and operation that is large enough to outweigh expected speculative gains on the relative price of fossil fuels; or there could be speculation as to future regulating costs not presently accounted in the cost of developing. The fact that corporations, whose output is complimentary to petroleum are not hedging the possibility of large price

increases in the fuel implies that hydro is an imperfect asset market.

A major difficulty in assessing the regulatory or institutional cost associated with a hydroelectric project is the form that these costs can take. A \$10,000 legal or engineering cost is understood and can be readily converted into one-fifth of a \$50,000 governor. However, when the cost occurs in the form of increased uncertainty, the translation to dollars is not obvious to the observer, although the developer has made the translation. It is difficult to say whether an increased probability of, say, an environmental lawsuit should be a \$5,000 or \$100,000 cost. What is the probability? What does the developer think the probability is? How much would he pay to reduce the risk? For a particular site, this is almost impossible to estimate. However, the general effect of risk on the necessary offsetting return may be observed by merely checking the range of yield on similar types, by maturity and size, corporate bonds whose only difference is perceived risk. Corporate Aaa to corporate Baa bonds historically have differed by over 15% of the Aaa bonds' yield. The risk factor could be translated into an incurred discount rate which implies an associated increased cost. For the example given in the cost section, an increase in the discount rate from 5% to 10% is equivalent to an increase in the construction costs of 70% with the discount rate constant. Uncertainty about future prices, costs, ability to operate, etc. all go toward increasing the discount rate. What the actual effect is today is unknown, but the potential effect on cost is very large.

A more traditional form of uncertainty takes the form of a gamble. The uncertainty over the preliminary permit, equipment costs, environmental controls, etc. are of the form of a lottery with many types of winning and

losing tickets. This hydroelectric generation lottery has a minor modification. There are N steps and the winnings of the first N-1 steps are tickets to play in the next lottery. The first step is to find what lottery must be played, i.e., does FERC have jurisdiction. Assume so, implying the developer plays the Federal lottery. The first lottery is the preliminary permit whose winning ticket is a ticket to the license lottery. Here there are multiple winnings depending on what is required to prepare the license, e.g., an environmental impact statement. Even if the developer has escaped any serious costs or delays when granted the license, the license is still subject to appeal in court. There is, of course, the risk associated with the straight costs and revenues, but this is a standard business risk which is, if anything, slightly lower for hydro than usual. The step by step risk taking in the hydro project may make the perceived risks of the project greater than a single step risk taking project with the same actual risk. This is a form of cost for which there appears no associated output.

V. Conclusion

In this paper the costs of construction and revenues from operation of a SSH site have been identified and a range of estimates provided. It was shown that this range included a profitable operation for sites with the given characteristics. Surveys of several sites show that these characteristics do exist. Yet, these sites have not been developed. By residual analysis, the cause was attributed to institutional costs. A rough look at the relative prices associated with hydroelectric generation reached the same conclusion. How much confidence can be placed on an analysis attributing the impediment to hydro development to regulatory costs when these costs are unknown? This is a question with two components. Are the costs and revenues approximately correct? Are there no other residual elements? The first may be checked, and there is obvious interest in potential corrections. With respect to the second part, it is apparent that there were no alternatives known to this study. It is thus taken as a working hypothesis that there are significant regulating costs imposed on the SSH developer. This information is insufficient to aid policy formation. Where in the regulatory environment can these costs be reduced with a net benefit to society? Obviously, all regulation could be removed, thus removing the costs, but this is neither feasible nor desirable. The relevant questions are (1) where is the regulation inefficient at obtaining its stated goals and (2) what policy options are available to remedy this institutional problem. It is for this reason that the primary emphasis at FPLC is on the legal-institutional questions as opposed to the straight economic and engineering questions.

The problems of valuing capacity, oil savings and pollution abatement from hydro are clearly subject to discussion. The question of how wholesale rates for small producers will actually be set under the new Energy Act is being studied at FPLC.

In closing, it may be noted that it was the purpose of this paper to stimulate policy discussion over the regulation of hydro. There is an obvious pro hydro development tone to the discussion. This is not an a priori view, but rather a point of departure for argument, since advocating the reduction of growth entails basically no change. The analysis presented is offered as a tool for your consumption, not a defense. It is just one of the several tools available. It is hoped you can use them.