

THE ECONOMIC AND POLICY ASPECTS OF SMALL HYDRO DEVELOPMENT IN  
BRITISH COLUMBIA

by

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## ABSTRACT

Small hydropower offers many advantages as a source of energy and it has been successfully developed by the private sector in the U.S. and in Ontario. Although there is considerable interest in developing British Columbia's vast small hydro resource, there has been very little progress to date. The reasons for this are related more to economic and political factors than to technical issues. In this thesis I review the situation in B.C. and propose a policy framework for energy purchase price, one of the main issues involved in small hydro development. The price offered small hydro producers for their electricity is clearly less than B.C. Hydro's avoided cost, but there is little evidence to support the amount offered. I suggest that, in the absence of an established, competitive market, energy purchase rates should be based on the utility's avoided costs, and that avoided costs be determined by amortizing the capital costs of the next scheduled project over a 20 year period, rather than basing them on the average levelized costs of all future projects. Furthermore, small hydro development should take a two-stage approach, similar to Ontario's, whereby energy is initially purchased at the utility's full avoided cost and later, when the small hydro industry has had a chance to develop, energy would be purchased at market value or through a competitive bidding process.

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## CHAPTER 1 : INTRODUCTION

I began my graduate research with two concepts in mind. The first was that engineers should be prepared to find solutions to economic, political, and social problems as well as technical ones, in order that projects benefiting society continue to be built. Engineers should be willing to take a leadership role in all phases of an engineered facility: conception, design, financing, government approval and regulation, construction, and operation. The second was that small hydroelectric generating plants were projects that had (1) many economic, environmental, and social benefits; and (2) a significant potential for development in British Columbia. Private sector development of small hydropower generation provides a good vehicle for exploring the economic, political, and technical factors involved in the multiple phases of an engineering project. These two concepts formed the basis of my research into private small hydro development in B.C.

Small scale hydroelectric power production by the private sector is not a new idea. In fact, the Canadian electrical industry got its start around the turn of the century with the construction of individual small hydro generating plants serving local needs. Later they were consolidated, and many were abandoned, as larger utilities, most of them provincial, assumed control of power distribution and began building larger scale projects. However, small hydro is making a comeback. After varying degrees of success in the U.S. and in

Ontario, there is now considerable interest in having British Columbia's vast small hydro resources developed by the private sector. For some it has been a long wait, for others it is a new opportunity. Yet there has been little development action to date.

The hold-up can be attributed to economic and political factors rather than technical issues. These types of problems, similar to many of those faced by engineers and managers, are often more difficult to resolve than the technical ones. In this thesis I review what is happening in small hydro development in B.C. and propose a policy framework for setting energy purchase prices, one of the main issues involved in small hydro development. The price being offered for small hydro power is well below B.C. Hydro's cost of new electrical generation, making small hydro projects that should be feasible, uneconomic. This has been one of the primary barriers to development in B.C.

Although many of the issues discussed herein are usually more associated with economics or commerce based research, the significance of this thesis in a civil engineering context lies in the fact that many of the problems faced by civil engineers are not limited to technical issues, and that the economic and policy issues of small hydro development in B.C. must be solved first before any significant "traditional" civil engineering work can be performed. At the same time the

concepts and techniques utilized all fall within the domain of engineering economics.

This thesis takes the following form: Chapter 2 reviews the progress made with small hydro development in other parts of North America. Special attention is given to Washington State because of its proximity to B.C. and to Ontario and Alberta as these are the only other Canadian provinces with progressive policies in place. Chapter 3 reviews the present situation in B.C. and the policies of B.C. Hydro. Chapter 4 discusses the value of energy and the concept of avoided cost and suggests a method for determining a utility's avoided costs. Chapter 5 examines in detail the value of small hydro power and B.C. Hydro's purchase price policy. Chapter 6 proposes a new policy to set energy purchase prices. Chapter 7 summarizes my conclusions and suggests a number of areas for further research into small hydro development.

## CHAPTER 2 : BACKGROUND ON SMALL HYDRO DEVELOPMENT

### 2.1 : Definition of Small Hydro

By "small hydro", I am usually referring to a hydroelectric plant with less than 5 megawatts (MW) of capacity. Although small hydro often includes capacities up to 20 MW, B.C. Hydro has made a distinction between over 5 and under 5 MW projects based on various technical, regulatory, and administrative concerns. To give an idea of the scale of 5 MW, B.C. Hydro's next planned hydro project, Site C on the Peace River, will have 900 MW of capacity and B.C.'s total generating capacity is over 10,000 MW. A 5 MW plant, for example, can serve over 1,000 homes. Other examples of power demands and capacity are given in Table 1.

### 2.2 : Virtues of Small Hydro

Looking at energy in global terms, there are obvious advantages to hydropower as a source of energy. It is a renewable resource, which is important in a world heavily dependent for its energy on non-renewable, depleting fuels such as oil, gas, and coal. Although some projects may have adverse environmental impacts, hydropower is non-polluting and does not contribute to the greenhouse effect with all its unforeseeable side effects. Small hydro also offers advantages over larger scale hydroelectric projects.

TABLE 1 : Hydropower Capacities

Definition According to Capacity:

Micro Hydro	1 kW - 100 kW
Small Hydro	100 kW - 20 MW
Medium and Large Hydroelectric Plants	> 20 MW

Power Demands:

Typical Home	1 kW - 20 kW
Community	approx. 3 kW/home
Farm, Small Business	10 kW - 50 kW
Industry	50 kW - 50 MW

Capacity:

Site C Project (not built)	900 MW
G.M. Shrum (B.C.'s largest)	2,416 MW
B.C. - firm hydro capacity (1989)	9,500 MW
- total capacity	10,500 MW
Canada - installed hydro capacity (1989)	57,900 MW
- total capacity	97,000 MW

Source: Ontario Ministry of Energy (1986), B.C. Hydro (1989), and Hocker (1989).

Although a large plant can usually generate electrical energy more economically than a small one, the economics of a hydro plant are very dependent on site conditions and, in the right circumstances, a small plant can be as economical or more so than larger ones. The relative cost of constructing large scale hydro facilities in B.C. has risen as many of the low cost, environmentally acceptable sites have already been developed (Sigma and Robinson, 1983, p.1-1). In contrast, the potential of small hydropower has largely been ignored and many of the relatively low cost sites are undeveloped. As a result, the cost advantage of large scale hydro development has decreased relative to small hydro power in recent years.

Small plants can be brought on line quickly and add capacity in small manageable increments, thus helping to keep the supply and demand for energy in balance. In contrast, large plants have long lead times and they provide large incremental additions to the capacity of their system, which can take time to absorb, and which often leads to a jump in electricity rates.

Small plants spread the economic benefits from constructing and operating generating plants over a wider range of time and geographical area. It has been shown that many small hydro plants can make a larger contribution to the province's economy than a few large ones (Schaffer, 1987, p.41). A large number of small hydro plants can also enhance the diversity of the electrical generation and transmission system. Finally, small hydro plants generally have much lower environmental impacts than large plants.

Small hydro is not without disadvantages, which include lack of energy storage, questionable "firm" capacity and reliability, lack of economies of scale, and greater susceptibility to damage from floods, sediment, and debris than larger plants.

Small hydro plants lend themselves well to private ownership, which is in line with world-wide trends towards the privatization of services and facilities previously provided by governments or other large agencies. Development and

ownership of small hydro plants by independent power producers allows for management on a scale more appropriate to the scale of the facilities than does ownership by government agencies or large utilities. B.C. Hydro has not expressed interest in developing small hydro themselves and this may be due to an inability to develop small sites cost-effectively because of high overhead and an organizational structure more appropriate for large projects.

Private development of small hydro plants also encourages local enterprise and local job creation, a goal of almost all governments. Most of the equipment and expertise required for small hydro design and construction can be found in B.C., thereby adding to the province's economic base. Major equipment for large hydro and thermal plants, on the other hand, often needs to be purchased outside the province or overseas. Independent power producers provide healthy competition for the provision of electricity, leading to a long term reduction of costs, and can add capacity to the province's system without increasing B.C. Hydro's debt.

Thus, it is easy to make the case that, wherever they are likely to be economical, the development of small hydro plants should be encouraged, and that they would be best developed, owned and operated by private developers, or Independent Power Producers (IPPs). However, there are a number of problems to be solved before a significant number of privately developed small hydro plants can become a reality. They revolve around

questions such as: "How should this resource be developed, keeping in mind the interests of the public, the developer, and other resource users including the environment?", "Who should get the opportunity to develop which sites?", and "How can a fair rate of payment be established for the energy produced?" Before examining these problems further, a brief description of the experience in the U.S., Ontario, and Alberta may provide some insights.

## 2.3 : The American Experience

### 2.3.1 : The Public Utilities Regulatory Policies Act (PURPA)

The North American small hydro resurgence got its start in the U.S. with the passage of the Public Utilities Regulatory Policies Act (PURPA) in 1979. PURPA was a component of a larger package of legislation, the National Energy Act of 1978. Spawned by the energy crisis of the 1970's, PURPA started a new direction in how energy resources in the U.S. would be developed over the following decade. The overall intent of PURPA was to foster development of efficient domestic sources of energy, including cogeneration and renewable resources such as hydro, wind, and solar, and to reduce dependence on foreign energy sources, most notably fossil fuels. PURPA mandated a guaranteed market for non-utility generated power and provided an attractive market opportunity for entrepreneurs to enter the field of electrical power production. Established utilities were generally



opposed to the requirements to accommodate and buy power from small power producers, and this led to some extensive legal battles before PURPA finally prevailed. Background on PURPA and the ensuing court cases is given in more detail in Appendix 1.

The Federal Energy Regulatory Commission (FERC), which was responsible for implementing and overseeing PURPA, established a standard for power purchases at full avoided cost. Avoided cost was defined as "the incremental cost to a utility of electrical energy which, but for the purchase from a qualifying facility, the utility would generate itself or purchase from another source" (WSEO, 1989, p.II-1). Individual states were given the power to establish their own rules, including how to determine avoided cost. Many states adopted the full avoided cost standard while others, such as New York, set a higher rate to promote development.

Although the expectations of PURPA were not quite clear, a 1980 report prepared for FERC predicted a total of about 12,000 MW of capacity to be provided by cogeneration and small power production under PURPA by 1995, 3500 MW of which would be from small hydro (Eden, 1985, p.582). The 12,000 MW target of total new capacity added under PURPA was exceeded in 1989 and by the end of the year, 519 hydro projects had come on line, representing 3,140 MW of capacity (Marier, Nov. 1989, Jan. 1990). Table 2 shows hydro project additions under PURPA from 1980 to 1989.

TABLE 2 : Hydropower Project Additions Under PURPA

YEAR	HYDRO PROJECTS ON-LINE	
	No.	Capacity (MW)
1980	8	251
1981	32	255
1981	32	275
1983	73	567
1984	81	486
1985	31	43
1986	111	296
1987	90	210
1988	30	419
1989	31	337
TOTAL	519	3,139

Source: Marier (Jan. 89, Nov. 89, Jan. 90)

This is quite an accomplishment considering the early resistance to the legislation. However, given the current energy surplus, a corresponding drop in avoided costs (largely due to low oil prices), the loss in 1986 of some significant tax incentives for some sources of power (including hydro), and increasing environmental opposition to hydro development, growth has slowed and the industry has consolidated. As well, FERC has been modifying its rules, relaxing the avoided cost standard, and proposing the use of competitive bidding to establish market value for power purchases from IPPs.

While many utilities feel that PURPA was a costly experiment which left them with long term contracts at rates above their present avoided cost, many others, especially

those in the private power industry, believe PURPA was very successful in paving the way for the development of small, private power production. According to the Washington State Energy Office, "...nationwide, PURPA has been extremely successful in stimulating the emergence of a multi-billion dollar independent power producing industry..." (WSEO, 1989, p.I-2).

### 2.3.2 : Independent Power Industry

Donald Marier, a long-time industry observer, states "...the growth of the independent energy industry is truly a success story which shows the value of competition in the power generation market" (Marier, 1990, p.2). Total independent power production capacity, which includes qualifying facilities (QFs) as well as independent power producers not covered by PURPA, is more difficult to quantify. A survey by the National Association of Regulatory Utility Commissioner's (NARUC) showed 17,189 MW of existing capacity as of June 1987 (Brown, 1989, p.22). According to a study by the Edison Electric Institute (EEI) which attempted to include most of the pre-PURPA capacity still operating as well as post-PURPA projects, the capacity of non-utility sources of energy was 25,323 MW as of December 1986, about 4% of total U.S. capacity (Brown, 1989, p.22). In California, for example, there was enough installed and under-construction capacity to boost the output of independent power producers to

25 percent of the state's total generating capacity (WSEO, 1989, p.I-2).

Independent producers will continue to be a dominant force in building new capacity over the next ten years. It is expected that in 1990, for the first time, the independent energy industry will bring on-line new capacity equal to that brought on by utilities (Marier, 1990, p.10). FERC estimates that 50% of capacity additions in the U.S. between now and 1997 will be from non-traditional generation (OMOE, 1989, p.2). The NARUC and EEI studies indicate that as high as 30 to 40% of new generating capacity in the U.S. will be built by independents over the next decade (Brown, 1989, p.22). The U.S. Department of Energy (DOE) is projecting that non-utility generation will grow at triple the rate of utility generation through the 1990's with independents adding 30,000 MW of new generating capacity from 1989 until the year 2000 (Marier, Jan. 1989, p.2). The Energy Information Administration (EIA) projects non-utility capacity to increase to 57,300 MW by the year 2000, or 7.4% of total U.S. capacity. Thus, IPPs are and will continue to be a significant source of electrical energy in the U.S.

### 2.3.3 : Washington State

Washington State, B.C.'s neighbour to the south, has more developed hydroelectric capacity than any other state in the U.S. and still has significant potential remaining. Over 170

MW of QF generating capacity has come on-line in Washington since the passage of PURPA, including 20 small hydro projects with a combined capacity of 77 MW (WSEO, 1989, p.I-3).

The State does not set avoided costs for its utilities but directs them to estimate their avoided cost and to adjust that in response to the apparent market price for power. Utilities are required to send out requests for proposals for new sources of power at least every two years. The proposals are evaluated on a number of bases, including price, environmental impacts, financial integrity, and fuel supply.

Power purchase rates are negotiated between the utilities and the independent producers. Prices may vary according to many factors including firm energy production, load following capability, performance guarantees, project start date, length of contract, and front-loading or levelization provisions. Power purchase contracts are thus tailored to specific project characteristics. State legislation also streamlines and simplifies the permitting process and provides financial incentives for renewable resources. For example, owners of certain power projects are allowed to pay a reduced business tax and are exempt from property taxation for seven years.

After the passage of PURPA, avoided cost projections were initially high because of the prediction of an electrical supply deficit. In Washington, a hydropower "gold rush" ensued. By mid-1982, developers had filed for over 250 hydro

projects. Speculators filed dozens of permit applications to secure rights on potentially attractive sites. When the electricity deficit became a surplus, avoided costs dropped as did interest in the development of hydropower and other renewable resources.

In contrast, avoided costs and purchase contract terms in California were set by the Public Utilities Commission (PUC) and based on high baseline and escalation rates for oil and natural gas. Under the PUC's "standard offer" system, California utilities were forced to sign contracts with unexpected and unprecedented numbers of QFs. Due to lags in regulatory response and the decline in oil prices, California utilities now pay much more for QF electricity than it costs them to generate at their own thermal plants.

## 2.4 : Canadian Experience

### 2.4.1 : Canadian Hydroelectric Industry

Hydroelectric power is a very important source of energy for Canada, especially in B.C. Currently, Canada has about 57,000 MW of hydroelectric generating capacity, representing 60% of its approximately 97,000 MW of total capacity (Hocker, 1989). Although the U.S. has more hydro capacity (85,000 MW representing 13% of the nation's total capacity), Canada actually generates more hydroelectric energy (Eden, 1989, and Hall, 1988). In fact, in the 1980's, Canada became the leading producer of hydroelectric power in the world. More

than 90% of Canada's power supply is provided by eight provincial government-owned utilities and one investor-owned utility. Ontario is the largest producer of electricity with 29,600 MW of total capacity (6,500 MW of which is hydro), followed by Quebec with 25,000 MW of total capacity (23,800 MW of hydro). British Columbia has 9,300 MW of hydroelectric capacity out of 10,500 MW of total capacity. Although hydro projects range in size from less than 1 MW to 2,400 MW, 99% of B.C. Hydro's hydro capacity comes from plants larger than 20 MW. In contrast, hydropower accounts for less than 20% of Alberta's 6,200 MW of capacity.

Before the 1980's, privately produced power was not a significant factor in Canada. However, the climate for private power projects is rapidly changing. Although in the past they did very little to encourage private generators, some utilities and provincial governments have recently adopted the view that private power has a larger role to play in providing a diverse and flexible source of electricity. Ontario has the most advanced and comprehensive policy to date, but both B.C. and Alberta are actively involved in promoting independent power production. I will first examine the situations in Ontario and Alberta in detail, and leave a discussion of B.C.'s policies to a later chapter.

#### 2.4.2 : Ontario Independent Power Program

The Ontario Government's Ministry of Energy (OMOE) has been a strong supporter of independent power generation (also referred to as Parallel Generation and Non-Utility Generation) and Ontario Hydro, the provincial utility, has been cooperative to a degree. In 1989, the OMOE issued a new policy on parallel generation that clearly sets out its policies, goals, and rationale. Although Ontario Hydro is not bound to adopt any or all of the policy recommendations, they appear likely to incorporate many key elements of the policy. The highlights of this policy and some of the related issues are discussed below.

Purchase rates, the government has stated, should fully reflect the value of the power to the electrical system and therefore should be based on avoided cost, which is defined as the cost that would otherwise be incurred by Ontario Hydro by generating the power itself or purchasing from other utilities. The calculation of avoided costs should take into account short and long term costs of power generation, transmission, distribution, and purchases; environmental costs; and social costs, where measurable. Ontario Hydro calculates its avoided costs based on system marginal costs and these are currently just below the average cost of power, which is based on historical accounting costs.

Electric consumers should continue to receive reliable electricity at reasonable rates; the development of parallel



generation should not increase costs to ratepayers in the short term and should reduce energy costs in the long term.

Ontario Hydro's methods for calculating avoided costs will be subject to public review and the results will be used to establish a schedule of purchase rates for all private generators, allowing for start-up year, contract duration, and capacity factor of the generator. Although Ontario Hydro has agreed to the review, industry representatives have criticized Hydro's implementation of the review process. Ontario Hydro has included the public review of avoided cost with the review of the Preferred Plan, their strategy for electrical generation for the next 15 years. However, they have already delayed the tabling of the Plan several times and the review of the plan itself may take 12 to 18 months. By delaying the avoided cost review, and thereby the purchase rate schedule, some parallel generators believe Ontario Hydro is attempting to "stymie the development of the independent power industry" (IPPSO, Sept. 1989, p.7).

All parallel generators should have access to electricity purchase rates on the same basis, regardless of energy source or technology. This includes making front-end loaded rates and loan incentives from Ontario Hydro available to all potential generators. Front-end loaded rates allow faster recovery of capital costs and are currently available only to renewable resource projects.

Parallel generation industry representatives have argued that the industry in Ontario is not yet sufficiently established to support competitive bidding and that the cost of preparing a winning bid would discourage potential developers. Without a developed industry, bidding may result in minimal benefits to ratepayers. They suggest delaying competitive bidding until the industry is established, competitive, and its potential known. In support of this position, the government recommends a process that encourages the development of the industry in the short term, at no added cost to the ratepayer, to ensure that they may benefit from a bidding process in the longer term.

For projects with capacity greater than 5 MW, the government proposes a two-stage solicitation process. In the first stage, all proposals, up to a capacity cap, meeting technical requirements would receive Hydro's avoided costs. If the offer was over-subscribed, bids would be chosen on a first-come, first-serve basis. Alternatively, the projects could be selected on the basis of criteria such as availability, reliability, and benefits to the system, although such a selection system could be seen as arbitrary. Through this process, Ontario Hydro should be able to solicit 1000 MW of development by 1995. In the second stage, a further 1000 MW of parallel generation could be solicited for development by the year 2000, depending on load growth and the results of the first solicitation, based on a competitive

bidding process. Presently, for projects over 5 MW, the utility holds a formal Request for Proposals (RFP) process, which solicits an unlimited amount of capacity. Purchase rates are negotiated for each project with a ceiling at the avoided cost.

Projects with capacity of 5 MW or less would continue to be welcome at any time and exempted from the solicitation process because they can be integrated into the system relatively easily. For these smaller projects a purchase rate schedule with standard rates would apply. Ontario Hydro presently has a standard rate structure for generators of 5 MW or less and these projects are integrated into the system on an on-going basis. The purchase price depends on the capacity factor and increases with the rate of inflation. Lower rates for lower capacity reflect that the lower purchase rate does not include a capacity component, just energy costs.

In May 1989, the standard base rate was set at 3.97 cents/kWh for a capacity factor (CF) of 65% or greater, and escalated each year at the Ontario Consumer Price Index (CPI) for up to 10 years from the in-service date (see Section 5.2 for a definition of capacity factor). Thereafter, the base rate is renegotiated. This rate is equal to 85% of Hydro's accounting costs for power (costs incurred by Hydro to generate, transmit, and distribute electricity using existing facilities) which is higher than the current avoided cost for power. When avoided costs exceed 85% of the accounting costs

of power (projected for 1991), rates will be based on avoided costs. A lower rate of 2.54 cents/kWh, based on Hydro's short term incremental energy cost, is paid for energy from projects with a CF less than 65%. Besides the standard rate, there are three other rate options for power purchases. The rate schedule is described in detail in Appendix 2.

One of the options offers a fixed 10-year rate for renewable resource projects, including hydro, solar, wind, and wood waste. These projects receive 4.94 cents/kWh for a 10-year period from the start-up date for a CF of 65% or greater. This rate is designed to encourage, and financially assist, development of non-utility generation from renewable resources by front-loading the forecasted standard rates over the 10-year period. This reduces the risks to private generators by allowing faster recovery of investment. This rate is limited to energy from renewable resources because these projects are expected to have long lives and be relatively insensitive to changes in market conditions.

The industry has criticized the purchase rate schedule because the purchase rate is roughly equivalent to the average cost of a new utility plant over its life in constant dollars, known as the levelized cost. This levelized cost is computed on the basis of paying this rate initially and then escalating it by the inflation rate over time. The accounting treatment of Ontario Hydro plants, on the other hand, allows a much higher recovery of the costs of the plant from rates in the

early years of the plant's life. A similar treatment to private generators would reduce their risks by reducing the project's payback period. I will discuss this problem of levelized cost versus accounting costs in more detail in Chapter 4.

For hydropower development on Crown land, application must be made through the Ministry of Natural Resources, which releases sites on the basis of competitive bidding. These projects, large and small, are exempt from Ontario Hydro's solicitation process. Instead, the successful applicant receives a standard purchase rate from Ontario Hydro. To prevent any one developer from monopolizing sites, the number of Crown Land sites that may be under development by any one proponent at any one time is limited to three. However, there is no consistent basis for awarding a site, and developers can waste money and time without ever developing a project. This process is now being reviewed and a new process should be developed by early 1990 which will include techniques for evaluating costs and benefits of projects and methodology for comprehensive river planning.

Total installed private generation capacity in Ontario was approximately 1200 MW in 1988. From 1985 to 1989, 25.5 MW of parallel generation capacity was added, 14.5 MW of which was hydro. In addition, 273 MW of new capacity has been committed, all of which should be developed in the next two years (OMOE, 1989, p.2). The government estimates that

between 150 and 250 MW of hydropower capacity could be developed profitably by the private sector. Out of 150 assessed sites, 52, representing a capacity of 67 MW, have been identified as being economic. However, hydro activity has slowed considerably recently as the more economic sites have already been developed and because of the uncertainties of the site release process.

Although the government realizes that private generation presents some major uncertainties, including reliability and long term availability, these risks are limited by the fact that parallel generation will account for a relatively small share of the system and specific risks can be limited further through purchase contract provisions. As a result, the government believes the risks of independent power production to the utility and ratepayers are likely to be manageable and are outweighed by the potential benefits.

#### 2.4.3 : Alberta Small Power Program

##### 2.4.3.1 : Small Power Inquiry

Unlike other provinces, the major utilities in Alberta are investor-owned. The largest, TransAlta Utilities Corp., operates 4,300 MW of total capacity. There has been a growing interest in non-utility small power production in Alberta since the early 1980's. The Small Power Producers Association of Alberta (SPPAA) and other potential private power producers have lobbied the government to develop a policy for private

generation, including alternative pricing provisions and contract terms for the sale of their electric energy production. In 1987 the provincial government called for a public inquiry by the Public Utilities Board (PUB) and the Energy Resources Conservation Board (ERCB). After a series of hearings, the Boards submitted a report outlining their findings and recommendations to the government in February 1988. The Boards' recommendations included the following:

- 1) the Alberta Government should adopt a policy that would facilitate the production of electricity by independent producers;
- 2) all types of power producers (including utility-owned projects) with individual generating capacities of 2.5 MW or less, from any power source, should be classed as small power producers (SPPs);
- 3) initially, a maximum of 100 MW of small power capacity could be interconnected to the Alberta system without affecting system reliability or increasing cost to consumers;
- 4) the price to be paid for small power generation should be based on long-term utility avoided costs and that price should vary according to the reliability and availability of the power, and the length and starting date of the contract;

- 5) small power generation should be reviewed after 1994, or when 100 MW is interconnected, whichever occurs first, so that its value to the electricity system can be fully assessed and the prices reviewed.

Fixed prices based on levelizing the utilities' avoided cost (i.e., taking an escalating rate and calculating an equivalent fixed rate) over the life of a contract were determined for 10, 15, and 20-year contracts. These prices, shown in Appendix 3, would remain fixed for the duration of the contract and vary depending on which year the contract begins. The Boards originally recommended that there should be separate prices for firm and as-available (secondary) power. However, they later determined that the prices should initially be equal and any necessary adjustments could be made when the program is reviewed.

The report also said larger non-utility power producers, with capacities greater than 2.5 MW, should continue to meet regulatory requirements and negotiate contractual terms with the utilities using the principles and methods outlined in the report. These include using the avoided cost as a ceiling for energy purchase price. A more complex regulatory process for larger projects is necessary to minimize any potentially adverse technical or economic impacts. The Boards recommended against using the concept of levelizing avoided costs to determine front-loaded fixed prices for non-SPPs because the default of such producers represents a significant financial



risk to the consumer. Further details of the Boards' views and recommendations are outlined in Appendix 3.

#### 2.4.3.2 : Small Power Development Program

In response to the report, the Alberta government announced the "Small Power Research and Development Program" in June 1988. This program was designed to help small power producers using renewable fuel sources of wind, hydro, and biomass. The program facilitates small projects so that the assessment of small power generation could be carried out in the near term.

Under the program, SPPs are able to contract with utilities to sell power from small hydro, wind or biomass projects less than 2.5 MW in capacity (except for a limited number of larger pilot projects) at a fixed rate of 5.2 cents/kWh. This policy in effect brings the price the Inquiry set for the year 1995 forward to the present with the goal of encouraging small power projects using renewable resources to come on-stream sooner. Electric utilities are not eligible for the program. These contracts are typically for 15 or 20 year terms. In addition to the renewable energy projects supported by the program, other small power projects could be developed by 1994 at prices set out in the report. The program began in October 1988 and is expected to run until 125 MW of eligible small power projects are interconnected to the system or the end of 1994, whichever comes first. The

benefits and potential contribution of small power, including deferring large generating plants, will be assessed at that time.

In November 1989, the government announced changes to the program to further benefit small power producers. The price paid for electricity from SPPs was increased and SPPs were given a choice between a fixed price or a price escalating with inflation. The program was also extended to include solar and peat power generation. The increase in the purchase price reflects the potential environmental benefits of using renewable resources to generate electricity. The fixed price option guarantees SPPs 5.2 cents/kWh until 1995, and 6.0 cents/kWh thereafter. The escalating option starts at 4.64 cents/kWh in 1990, and then escalates with inflation. The utility is required to pay these prices for 10 years, after which time the prices will be set by the Public Utilities Board. In addition, small power producers would be eligible for the utility companies' income tax rebate program. Under the tax rebate program, income tax paid by utilities is rebated and passed on to power consumers. This will allow small producers to receive the same income tax treatment as the large generating utilities.

## CHAPTER 3 : SITUATION IN B.C.

### 3.1 : Government Policies

B.C. Hydro's interest in encouraging IPPs is a direct result of provincial government directives. The government has four goals in encouraging the development of private power:

- introduce more competition into the electrical production industry;
- export of electricity by the private sector;
- improve efficiency and reduce costs of the system;
- encourage private sector investment in power production (Swoboda, 1990).

Jack Davis, B.C. Minister of Energy, Mines, and Petroleum Resources, has said that much of the growth in B.C.'s electricity demand will be met by private sector power projects instead of B.C. Hydro. While B.C. Hydro, a Crown corporation, will remain the dominant player, the government intends to rely as much as possible on the marketplace to provide increased power generation for both the domestic and export markets (Lewis, April 5, 1990).

Although these are stated goals of the ruling Social Credit Party, there are some indications that the opposition New Democratic Party (NDP) would also support private power production to some extent. Mike Harcourt, leader of the NDP, recently stated that the NDP prefers smaller generation

projects over large ones, and export of firm electricity would be permitted only if the sale price covered all long-term costs, including social and environmental costs (Lewis, April 8, 1990).

### 3.2 : B.C. Hydro Policy

To meet these government objectives, B.C. Hydro has announced a policy of encouraging private power development in four separate areas: projects for non-integrated areas (those areas not connected to the main power supply grid), projects developed for the export market, and projects over 5 MW and projects of 5 MW or less connected to the integrated system for domestic use. For the purposes of this paper, I am generally referring to projects under 5 MW connected to the integrated system as this is where most of the small hydro potential lies. For example, a 1983 study by Sigma Engineering for the provincial government, "Small Hydropower Resource in the Provincial System," identified over 600 potential small hydro sites under 20 MW representing over 1400 MW of capacity. Sigma estimated that approximately 80 sites generating a total of 430 MW could be developed by the private sector at or less than the cost of B.C. Hydro's proposed Site C project. Projects of 5 MW or less are also eligible for a streamlined regulatory and administrative process, including a standard purchase rate and contract, which allows for a more general approach to policy evaluation.

B.C. Hydro defines independent power production as electricity generated by an independent or privately-owned facility which is connected to the B.C. Hydro system. The utility's policy statement on IPPs says in part:

In its effort to achieve the most economic supply of electricity, B.C. Hydro is turning to IPP's for a portion of its electricity supply requirements. Cost effective independent power production should allow deferral of larger, potentially more expensive projects on the integrated system. (B.C. Hydro, May 1989, p.6)

B.C. Hydro states that the benefits of independent power production include:

- smaller projects;
- defer large plants;
- alleviate rate shocks;
- less environmental impact;
- distributed economic development;
- competition;
- enhanced government revenues;
- reduce losses of supplying power to non-integrated areas (Swoboda, 1990).

For projects less than 5 MW, B.C. Hydro will invite proposals for the supply of electricity through a Request for Proposals (RFP) process in the spring of each year, as new generation is required, up to a predetermined maximum total. To minimize administration and transaction costs and to facilitate the development of independent power projects under

5 MW capacity, standard conditions, including the purchase price, apply to these projects. According to B.C. Hydro, the purchase rate will be set annually at a value that reflects B.C. Hydro's incremental cost of electricity. The price is to be announced at the time of the RFP issue and be subject to escalation. Purchase agreements will be entered into on a first come, first serve basis until the aggregate capacity of the agreements is approximately equal to the predetermined maximum total.

The contract will have a 20 year term initially, with the option to renew each year thereafter. The project is required to provide a minimum amount of kilowatt-hours (kWh) per year. The purchase rate is currently set at 3.0 cents/kWh for the first year, plus adjustments each year after that equal to changes in the Consumer Price Index (CPI) for Vancouver, but not exceeding 3 percent/year.

To secure a contract with B.C. Hydro, the IPP must be able to:

- 1) demonstrate, through previous experience and/or performance guarantees, an ability to design, finance, construct, and operate the proposed project;
- 2) meet the standards for electricity quality, reliability of supply, and safety, and be compatible with the B.C. Hydro system;

- 3) pay for interconnection costs and required modifications to existing B.C. Hydro facilities;
- 4) pay fee(s) to B.C. Hydro to assist in defraying its costs of evaluating the proposal;
- 5) obtain all necessary approvals, licences, and permits to comply with all regulatory requirements.

B.C. Hydro's policies with respect to IPPs are presented in more detail in Appendix 4.

There are several major differences between the under-5-MW process and the over-5-MW process worth noting. Following a public RFP process, B.C. Hydro will purchase electricity from projects greater than 5 MW at rates and other terms based on competitive negotiations, provided that the quality is acceptable and the cost to B.C. Hydro is lower than the cost of other available alternatives. The electricity purchase price and other conditions for these projects will be negotiated and B.C. Hydro will seek financial arrangements which optimize benefits to the utility and its ratepayers. B.C. Hydro will consider alternative price structures and/or financing arrangements, with appropriate guarantees, to assist these projects. The competitive negotiation process is outlined in Appendix 4.

The intent of this process is to negotiate a price that provides the lowest cost to B.C. Hydro ratepayers and reflects

the values of firm and secondary energy. Factors affecting price include:

- dependability and reliability of energy supply;
- duration of supply;
- impact on the transmission and distribution system  
(e.g., proximity to the Lower Mainland).

Performance guarantees may be required to reduce the risk, both front-end and operational, to B.C. Hydro.

### 3.3 : Progress to Date

While B.C. Hydro borrowed from lessons learned from other utilities in the U.S. and Ontario in setting their policy for the over-5-MW projects, for the under-5-MW process they seem to be allowing the policy to evolve gradually. For the initial Request for Proposals for under 5 MW released in May 1989, B.C. Hydro received responses from 10 firms, all based in B.C., representing 14 hydroelectric projects, with a total capacity of 47.6 MW. These projects are scattered throughout the province. While representatives of B.C. Hydro feel that purchase agreements will be entered into with most of the project sponsors, as of March 1990 only one contract, a small 62 kW project representing less than 1% of the total capacity offered, had been signed.

There are several factors which may account for this lack of action in B.C.: price for power produced, allocation of sites on Crown land, environmental concerns, and the



regulatory process. However, the main obstacle to the development of these proposed projects seems to be the price offered by B.C. Hydro for the power the projects will generate. Industry representatives feel the purchase price is too low and that many of the proposed projects are not economically feasible at the rate offered. These small hydro projects are being offered a standard 20 year contract and a standard price for energy, which is now set at 3.0 cents/kWh beginning the year the project comes on line and escalating at a rate equal to changes in the Vancouver CPI or 3% per year, whichever is less. Presumably, the offering of a low rate initially aims to limit the number of projects and get the energy at the lowest possible price.

There are several problems with this pricing policy. While the 3.0 cents/kWh rate was first announced in June 1988, there has been no provision to escalate it with inflation up to the in-service date of the project, which could be 1991 or later. The longer it takes to negotiate and secure a contract, the less revenue, in real terms, the developer will receive. This especially becomes a cause for concern for developers when B.C. Hydro is responsible for delays. The escalation rate, which does not start until one year after the in-service date, is set at a maximum of 3% per year, yet inflation has averaged 5.7% per year and the cost of electricity has escalated 4.5% per year for the past 25 years (Synex, 1990, p.3). The 3.0 cents/kWh figure is also less

than B.C. Hydro's value of firm electricity, and lower than purchase rates in Ontario and Alberta of 3.97 (\$1989) and 4.64 (\$1990) cents/kWh respectively, which escalate at the rate of inflation over the life of the contract. Thus, the question is raised whether or not this is a fair pricing policy for small hydro projects under 5 MW. To answer this question, I will now examine the cost of hydroelectric energy in more detail.

## CHAPTER 4 : PRICING HYDROELECTRIC ENERGY

### 4.1 : Principles of Energy Pricing

The characteristics of electricity distribution and transmission are such that the industry is most efficiently operated when a monopoly is granted to an electrical utility. As a result, there is no free market for electrical energy and the utility is a monopsonist. In most cases it is not possible nor feasible for an IPP, especially a small power producer, to sell power to any other buyer. Rates thus have to be set by processes other than the free interplay of market forces. Most people would agree on the following principles:

- the rates for power from each project should be as low as possible for maximum benefit to the utility's customers, and they should certainly be no higher than the utility's avoided cost;
- the rates paid for the power should be sufficiently high to attract developers, allow them to finance their projects, and encourage them to innovate;
- the risks associated with the development, financing, and operation of each project should be fairly allocated between the developer and the utility.

Difficulties in deciding on fair rates of payment arise from the capital intensive nature of hydro developments which necessitates a long term energy purchase contract to secure

the financing; the different methods for financing private developments and those of a major utility; the utility's monopoly on the purchase of energy, which precludes the setting of rates by competition in the marketplace; and the uncertainties associated with the long-term horizons of power contracts, including inflation, interest rates, taxes, construction and operating costs, etc.

The demand for electrical energy varies continuously. If a utility cannot meet the demand, some of its electrical load must be "shed", resulting in a power cut-off or a brownout. In North America, standards are high and utilities are most reluctant to shed loads except under emergency conditions. Thus, to meet the continuously varying loads the utility must have enough capacity to meet the peak demand and enough "stored" energy to keep meeting the energy demands.

Since each customer connected to the electrical system has the "right" to use any amount of electrical energy up to the capacity of the connection, the customer has a "call" on a certain amount of generating capacity, which in theory is dedicated to his or her use, whenever they want it. There is a cost to supply this peak capacity capability, as well as a cost for supplying the actual amount of energy used. This cost is passed on to customers in Europe and large customers in North America, who pay a demand charge based on their peak demand as well as an energy charge. With thermal generation, the peak demand charge depends on the cost of the generating

and transmission facilities (usually the fixed costs), and the energy charge depends on the amount of fuel used for generation (the variable costs). With hydro power, the cost split is not so clear cut, but the same principles apply. This adds to the complications of setting fair rates for small plants that supply only part of the load.

The rate offered for electricity should also reflect the length of the purchase contract and the risks assumed by the developer. Obviously, a long-term contract with performance guarantees is worth more than energy bought on a temporary or "spot" basis. If a developer takes on the financial and technical risks of power plant construction and operation, the utility benefits because it is able to lower its risk exposure.

There are many different ways to pay for electricity over a long-term contract. Clearly, a small developer would prefer a higher rate in the early years to service his debt and pay off his capital, and could then accept lower rates, based on operating and maintenance costs only, in later years. For example, the rate could be set such that capital costs could be paid off in the first 20 years of a contract, and, upon renewal, the rate would be decreased to reflect only operating and maintenance costs, provided that the payment stream has the same net present value as the value of power to the utility for the same duration. However, there are risks to the utility in such an arrangement in that the plant may not

operate long enough for the utility to benefit from the low-cost electricity promised in the future.

While the utility's customers benefit in the short term from the lowest rates possible, if the purchase price is set too low, several problems may arise. Projects that can produce power for less than the utility's avoided cost will not be built. The risk of the project failing, either financially or technically, is increased as developers cut corners in design and construction. Developers may not develop a site to its maximum potential, which is not an efficient use of the resource, or they may be discouraged from innovating. In the attempt to reduce capital costs, developers may be tempted to forsake operational and maintenance considerations in the design stage, leading to higher operating costs in the future. Thus, it may be advantageous in the long run for a utility and its ratepayers to pay a little more up-front for power, with the expectation of paying less in the future, for more efficient, reliable, and long-lasting private sector development.

#### 4.2 : B.C. Hydro's Energy Costs

There are many ways of valuing energy. There is the value of energy based on historical costs, and that based on future costs. Future costs can be either short-term marginal costs or long-term costs. Long-term costs can be broken down into firm energy and secondary energy. Firm energy can be

expressed in terms of a "capacity" component and in terms of an "energy" component. Because of all these distinctions, any discussion of energy costs must first define the type of energy.

B.C. Hydro essentially has three sets of power prices: historical average costs, short-term marginal costs, and long-term marginal costs. It now costs B.C. Hydro 4.4 cents/kWh (in 1989 dollars) to generate, transmit, and distribute electricity (note that other costs discussed below are primarily production costs and do not include the cost of distribution). Since B.C. Hydro's average cost of production is based on historical capital costs that are considerably less than today's replacement costs, average costs may not reflect the value of additional power to the system and instead we should examine the marginal costs of producing power.

The short-term marginal value of power is based on incremental production costs to the in-service date of the next plant or, in other words, the cost to produce an extra kWh of electricity with the existing system. B.C. Hydro uses their short-term values for evaluating short-term project modifications as well as evaluating potential power purchases and coordination agreements with other utilities. Thus, this is the price B.C. Hydro is willing to pay for power on a short-term or "spot" basis. The short-term value of energy will increase over time, as a result of inflation and also in

real terms as B.C.'s energy surplus diminishes. The value of this energy rises from 1.8 cents/kWh in 1989 to 4.9 cents/kWh in 1999 (in 1989 dollars) as shown in Table 3. Figure 4.1 shows the effect of inflation on the value of energy by displaying the same figures in nominal dollars using B.C. Hydro's assumed long-term average annual inflation rate of 4.5%.

TABLE 3 : B.C. Hydro's Marginal Value of Energy

(cents/kWh in constant 1989 dollars)

Year	Value of Electricity	Firm Capacity	Firm Energy	Secondary Energy
1989	1.80	0.12	1.70	1.10
1990	1.80	0.12	1.70	1.10
1991	1.80	0.12	1.70	1.10
1992	1.90	0.12	1.80	1.10
1993	2.00	0.12	1.90	1.10
1994	2.30	0.12	2.20	1.10
1995	2.20	0.12	2.10	1.10
1996	2.80	0.12	2.70	1.30
1997	3.40	0.12	3.30	1.50
1998	4.20	0.12	4.10	1.70
1999	4.90	0.48	4.40	1.90
2000 and on	5.00	0.48	4.50	2.00

Source: B.C.H.'s "Value of Electricity" (August 1989)

Although it is usually customary to ignore the effects of inflation and work with real dollar figures, I will work mostly with nominal dollars for several reasons:



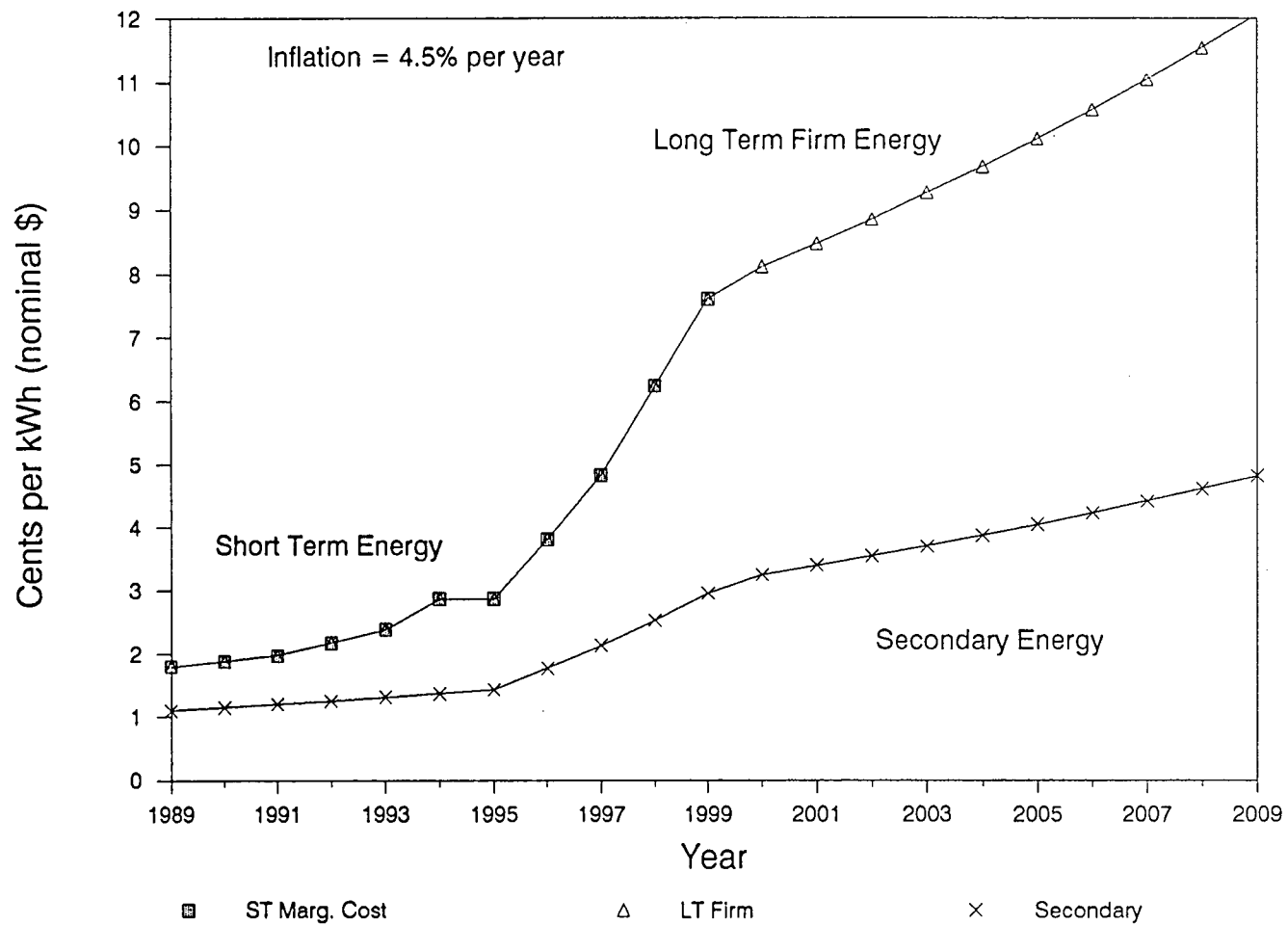


FIGURE 4.1 : B.C. Hydro's Marginal Value of Energy

Source: BCH's "Value of Electricity" (August 1989)

- it is useful to illustrate how costs and energy values change due to inflation over a long period of time;
- Net Present Values calculated with nominal dollars and a nominal discount rate are equal to those calculated with real dollars and a real discount rate;
- B.C. Hydro's constant dollar figures are calculated using an assumed long-term rate of inflation.

The long-term value of power is a time-weighted average cost of future projects included in B.C. Hydro's Resource Plan. This is B.C. Hydro's projected value of future power generation. B.C. Hydro's long-term levelized value of firm electricity is 5.0 cents/kWh in 1989 dollars. There is a difference between firm energy, which can be relied upon, and secondary energy, which is not guaranteed and as such is worth slightly less.

Firm energy is the assured energy output in kWh of a hydro generating plant over one year. B.C. Hydro defines the firm capability of its system as the annual energy available during an extended period of below average streamflows (what they call the critical period). In other words, firm energy is the minimum annual output of a hydro plant under extremely low streamflows. Firm energy can be broken down into two components and priced accordingly:

1) Dependable Capacity

This is valued on the basis of peak capacity, measured in \$/kW/year, and expressed in the equivalent cents/kWh. In the short term, B.C. Hydro bases the value of capacity on recent marketing opportunities for their surplus capacity which is about 0.1 cents/kWh (\$1989). The value of capacity in the long term is based on the cost of adding more peaking capacity (but not more total energy output) to the existing system (at the Mica and Revelstoke projects) and this cost is equivalent to 0.5 cents/kWh (\$1989).

2) Dependable Energy

This is the value of the energy component, which B.C. Hydro calculates by subtracting the value of capacity from their total long-term value of electricity. The incremental value of firm energy is estimated at 4.5 cents/kWh (\$1989).

B.C. Hydro defines its value of firm electricity as the sum of the values of firm capacity and firm energy.

Secondary energy is the energy that is available over and above firm energy when water conditions are favorable. Secondary energy may not always be available and cannot be "guaranteed" or relied upon. Its long-term value is presently estimated to be 2.0 cents/kWh (\$1989). Figure 4.1 shows the

long-term value of firm and secondary energy in nominal dollars.

The value of small hydro energy output is related to how "dependable" it is. That is, whether the energy is always available when it is required. Output of this nature has "capacity value". If, on the other hand, the output is available independent of system requirements, then the value corresponds to the marginal costs of the system at the time the output is available. This is termed the "energy value". Because of the nature of small hydro power, often only the energy value, with no capacity value, is attributed to the output of small hydro plants (Sigma, 1983, p.2-6). I will discuss this concept in more detail in Chapter 5.

#### 4.3 : Avoided Costs

When a utility purchases power from an independent producer, it displaces the cost of acquiring power from other sources. The avoided cost is the cost that would otherwise be incurred if the utility had to generate the power itself or purchase from another utility. By buying power from small producers, the utility can delay, at least temporarily, planned new generating facilities and "avoid" their associated costs. In the absence of a competitive market for the supply of electricity, avoided costs would seem to be a fair basis for setting a price for purchasing power from independent producers, and this is the accepted standard in the U.S. and

Ontario. The purchase of power at a utility's avoided cost is also, in theory, economically efficient. To this end, B.C. Hydro has recently adopted a policy of meeting future energy needs at the "lowest total resource cost" and this can be achieved "by setting the ceiling price for all resource acquisitions, regardless of origin, at the avoided cost of new electricity" (B.C. Hydro, November 1989, p.13-3). There can be a problem, however, in actually determining avoided costs, especially long-term costs.

Long-term avoided costs may be based on a specific avoided plant, a theoretical "proxy" plant, an aggregate of costs from all potential future projects, or other more complicated means. B.C. Hydro, for example, presently bases their long-term avoided costs on the time-weighted, average levelized cost of future projects.

Determination of avoided costs should be relatively simple and easy to understand on the one hand, and reasonably accurate and realistic on the other. Given uncertainties in future load demands, technology development, interest rates, inflation, environmental requirements, etc., determining costs beyond the next planned project with any precision is difficult. The only cost estimates that may be reasonably reliable will be those of the next plant to be built. Thus, I suggest basing long-term avoided costs on the cost of the next planned project. This method is simple in that complicated formulas or computer models do not have to be used. It is

accurate in the sense that guesses such as what type, what size, how expensive, and when will they be needed, do not have to be made about a multitude of future plants.

B.C. Hydro's next major generating facility is well documented: it will be the 900 MW Site C hydroelectric project on the Peace River in Northern B.C. which could come on-line as early as 1999 (note that the addition of up to 240 MW of generating capacity at the existing Keenleyside Dam will likely be built first and capacity additions are planned for several other existing hydro sites).

#### 4.3.1 : Avoided Costs of Site C

The cost of building B.C. Hydro's next large generating plant, Site C, is included in B.C. Hydro's long-term value of power. Table 4 shows Site C project costs and we can determine the avoided costs of Site C as follows.

Capital costs include estimated construction costs, corporate overhead, interest during construction, and inflation during construction. B.C. Hydro's fixed operating costs include:

- operation and maintenance;
- insurance;
- administration and general expenses;
- grants (in lieu of property taxes);
- interim replacement costs.

TABLE 4 : Site C Project Specifications and Costs

Peak Capacity:	900 MW
Firm Energy Output/yr.:	4570 GWh
Average Energy Output/yr.:	4710 GWh
Total Capital Cost:	\$2053 Million (\$1989)
Annual Fixed Cost:	\$33 Million (\$1989)
Annual Variable Cost:	\$17 Million (\$1989)
Levelized Unit Energy Cost:	4.71 cents/kWh (\$1989)

Assumptions: Discount Rate = 12.85%, Inflation Rate = 4.5%, Project comes on line in 1999, 7 year construction period, 70 year life.

Source: B.C.H's "20 Year Resource Plan" (April 1989) and "Value of Electricity" (August 1989) and Appendix 5.

Generating facilities on the Peace and Columbia River system are exempted from paying school tax and B.C. Hydro does not pay income tax. Variable operating costs for a hydro plant basically consist of the energy portion of the water rental fees, which is 0.4 cents/kWh. Water rental fees are charged by the provincial government for use of the province's water. In contrast, a thermal plant's variable operating costs would include primarily fuel costs. However, a thermal plant is not required to pay for the air it consumes.

It should be noted that since the province owns B.C. Hydro, costs such as grants in lieu of taxes and water rental

fees are not really costs in a true economic sense but transfers back to the government (and, in turn, back to the citizens who are also B.C. Hydro's customers). However, since B.C. Hydro passes these types of costs directly on to the ratepayer and it is the total direct cost to the ratepayer that will ultimately determine the value of IPP power, for the purposes of this paper I will treat such items as real costs.

Figure 4.2 show these costs over the expected 70 year life of the project in nominal dollars. Capital costs are assumed to be incurred at the beginning of the first year of operation. Annual fixed and variable operating costs are assumed to be incurred at the end of each year, and rise at the rate of inflation.

#### 4.3.2 : Different Accounting for Site C Costs

The costs of Site C and other future projects are usually stated as a levelized rate over the life of the project. It takes total capital cost and fixed and variable operating costs over the life of the project, and, using a discount rate net of inflation, determines an equivalent annual cost in constant dollars. In other words, it takes the Net Present Value of all capital and operating cash flows, and spreads it out over the life of the project. Levelized cash flows for Site C are shown in Figure 4.3 in nominal dollars, which start off in Year 1 as the levelized cost and escalate at the rate



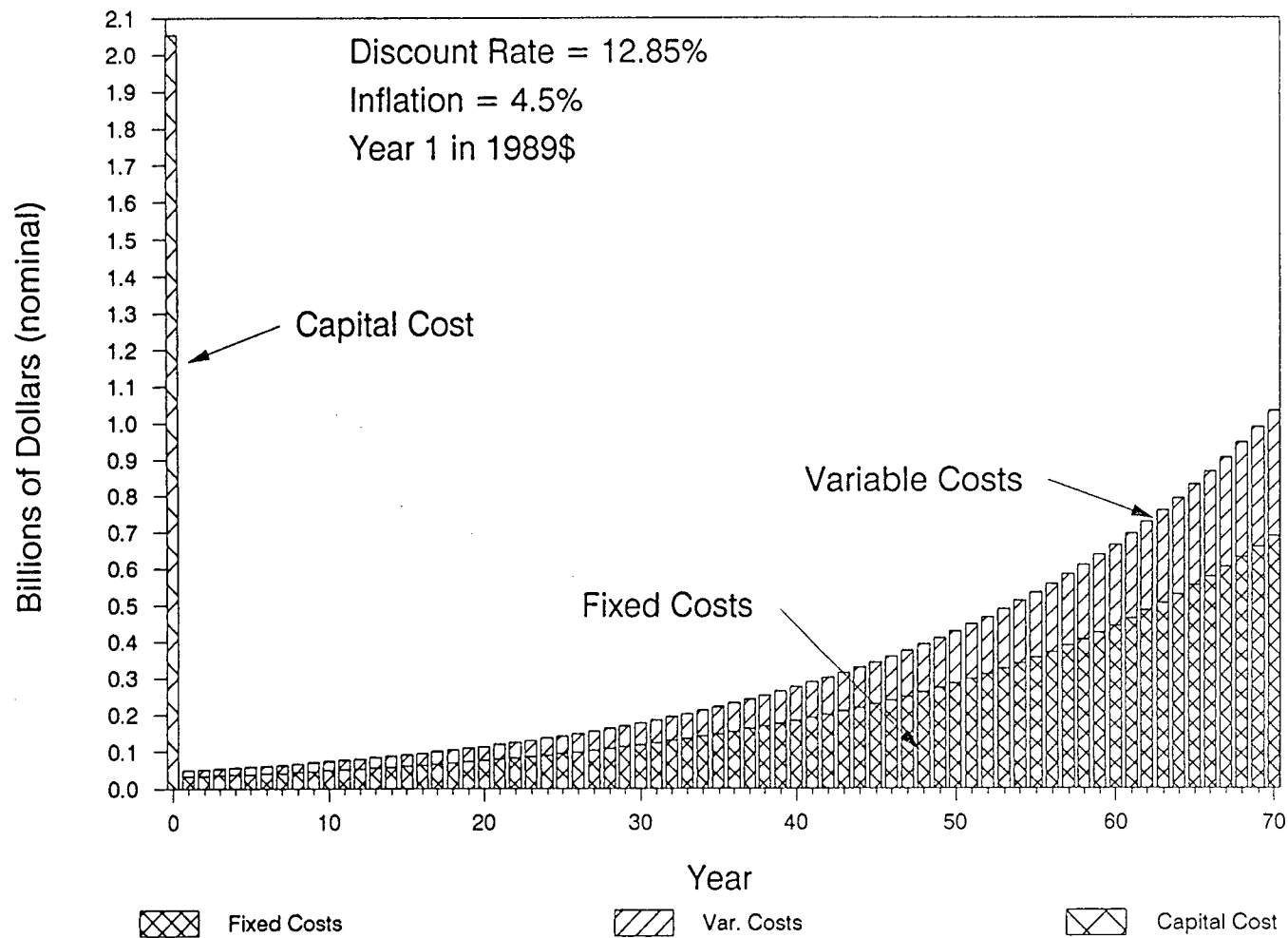


FIGURE 4.2 : Site C Project Cash Flows

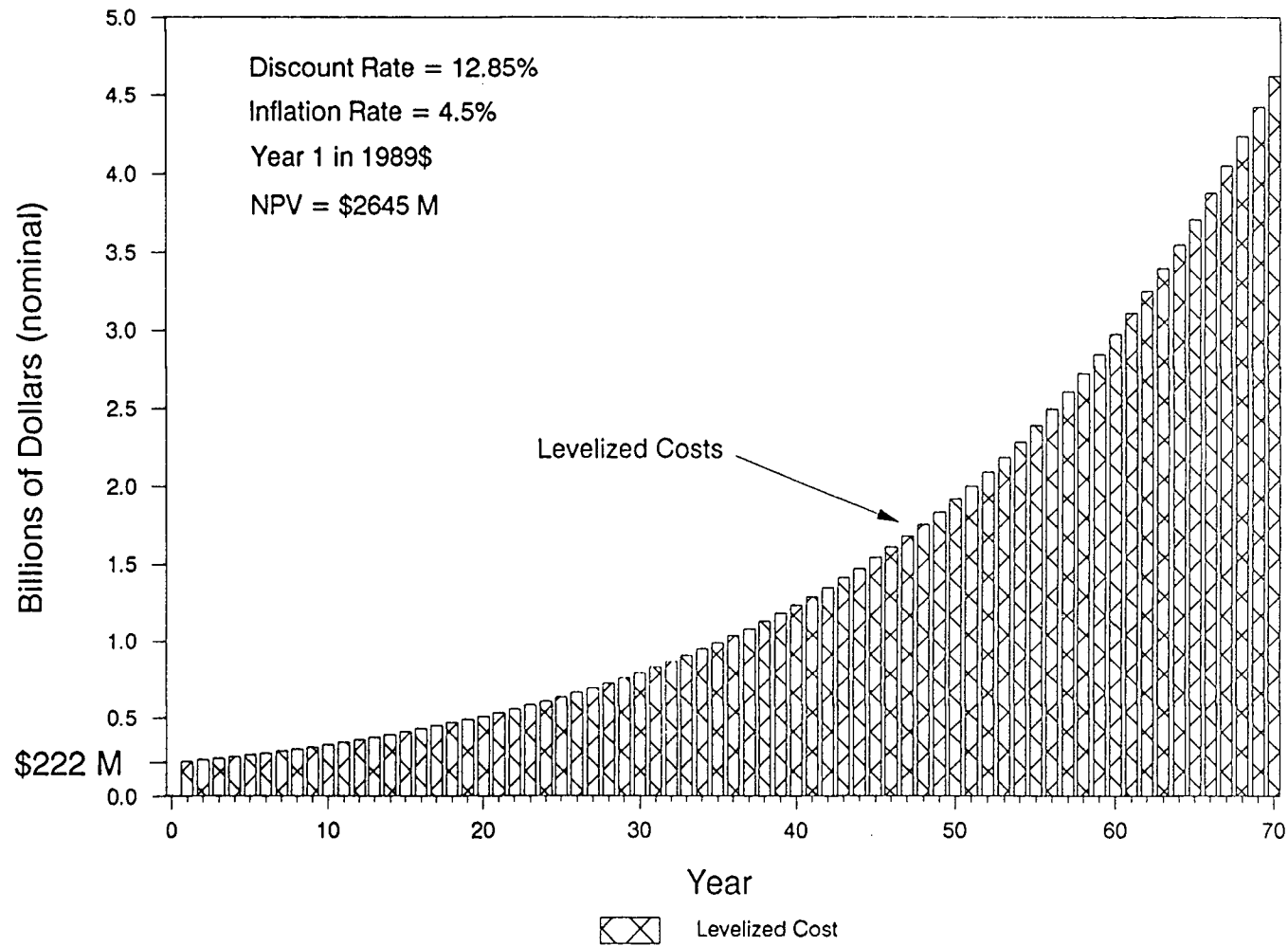


FIGURE 4.3 : Site C Levelized Cash Flows

of inflation over the life of the project. B.C. Hydro uses levelized costs in determining their long-term avoided costs.

However, the levelized cost does not represent actual expenditures by B.C. Hydro for power. To pay for the capital cost of the project, B.C. Hydro would borrow by issuing long-term debt and then pay off the loan over time. If the capital costs are amortized over the life of the project, 70 years, the capital costs are depreciated at a constant rate each year for 70 years, assuming straight-line depreciation. Real expenditures would consist of initially high, but declining, interest payments, a constant depreciation (sinking fund) cost, and rising operating costs, as shown in Figure 4.4 (after McDonnell, 1989). However, only a large utility or government agency could afford to account for costs over such a long time frame in this way.

A private company would use a much shorter depreciation term, paying off capital costs in 20 years, for example, as shown in Figure 4.5. In this case, interest payments and depreciation costs stop after year 20, leaving only rising operating costs for the remainder of the project's life. A 20 to 30-year depreciation term is more reasonable for several reasons:

- the effects of discounting beyond this time span are negligible, e.g., cash flows discounted back 20 years at 12% are only worth 10% of their future value;

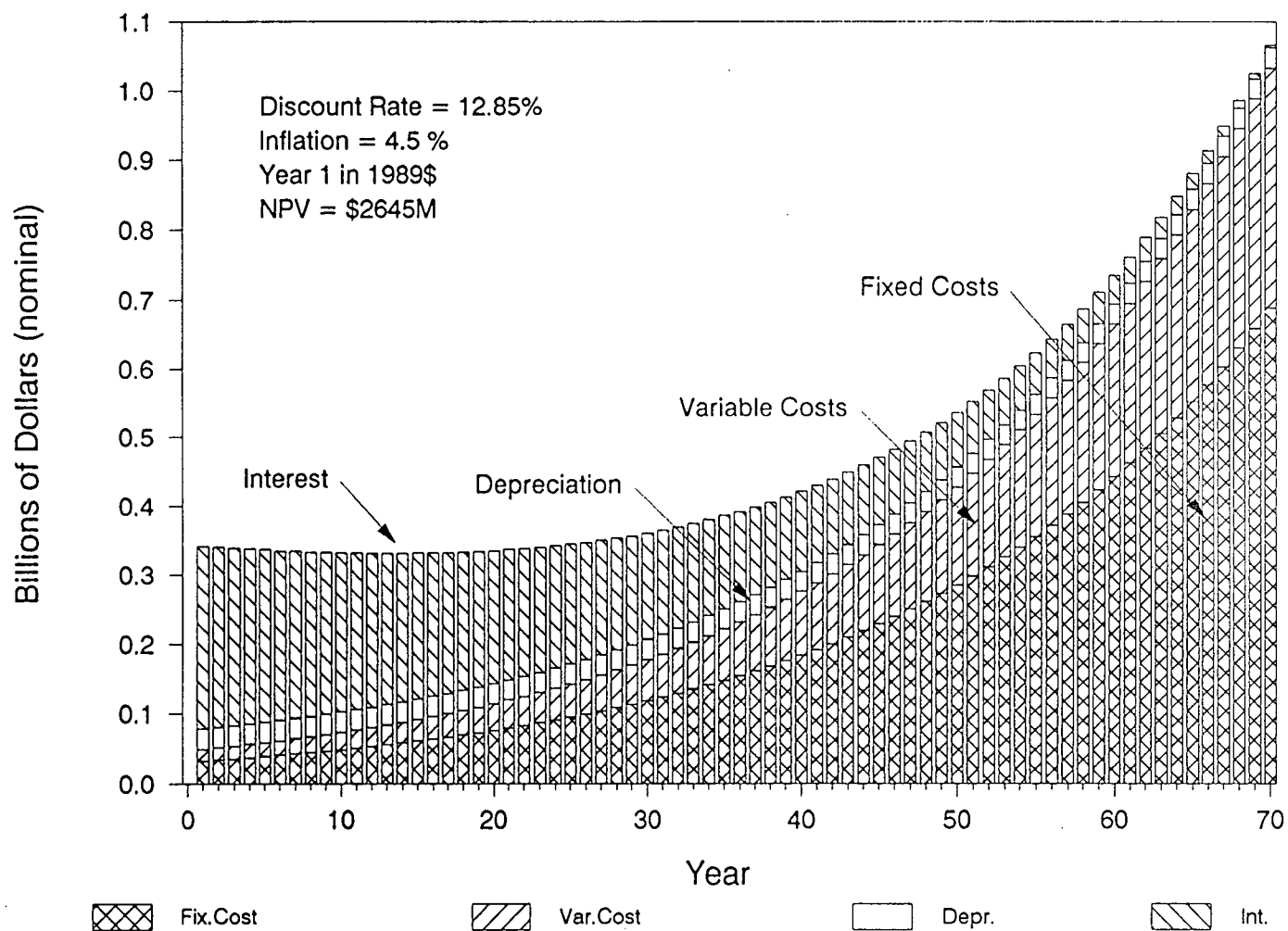


FIGURE 4.4 : Site C Cash Flows - 70 Yr. Depreciation

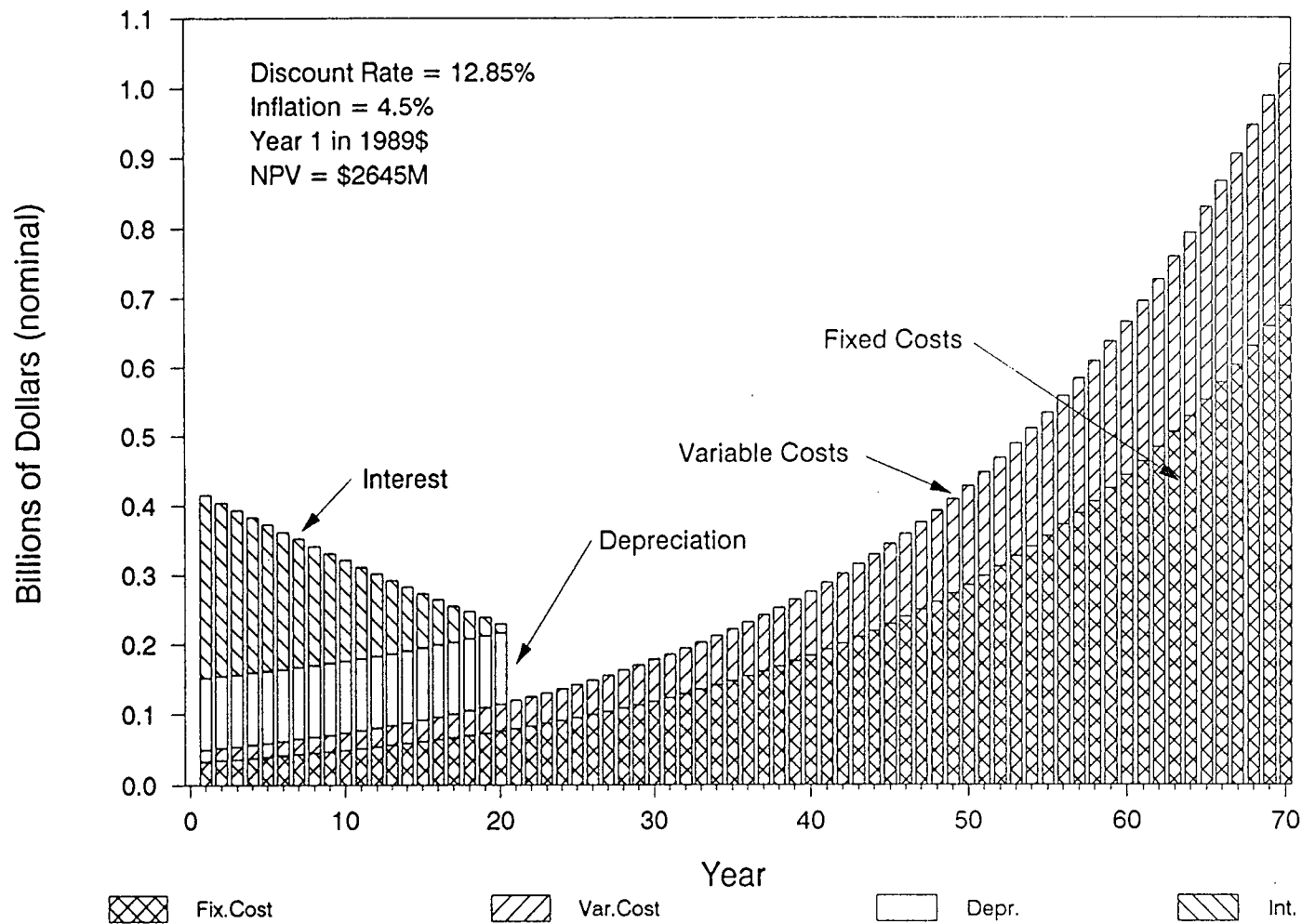


FIGURE 4.5 : Site C Cash Flows - 20 Yr. Depreciation

- the risks and uncertainties beyond this time span become incalculable, e.g., who knows what interest rates, inflation, and power demand will be 1 year from now let alone 20 years;
- other sources of power may be developed in the future that may be significantly cheaper or less harmful to the environment, rendering the present project obsolete and uneconomic;
- B.C. Hydro does not issue bonds for terms greater than 25 years, reflecting investors' maximum time horizon.

Dividing the total annual costs by the average annual energy output gives an annual unit energy cost. Although B.C. Hydro bases its long-term unit costs on firm energy output, unit costs for individual hydroelectric projects are based on average energy capability. Average annual energy output includes some secondary energy and is thus slightly greater than firm energy output. B.C. Hydro estimates the levelized unit energy cost for Site C as 4.71 cents/kWh in 1989 dollars. This rate starts off at 4.71 and escalates at the rate of inflation over the life of the project.

These three methods of cost accounting for Site C - levelized cost, 70-year depreciation term, and 20-year depreciation term - are shown in Figure 4.6, which shows

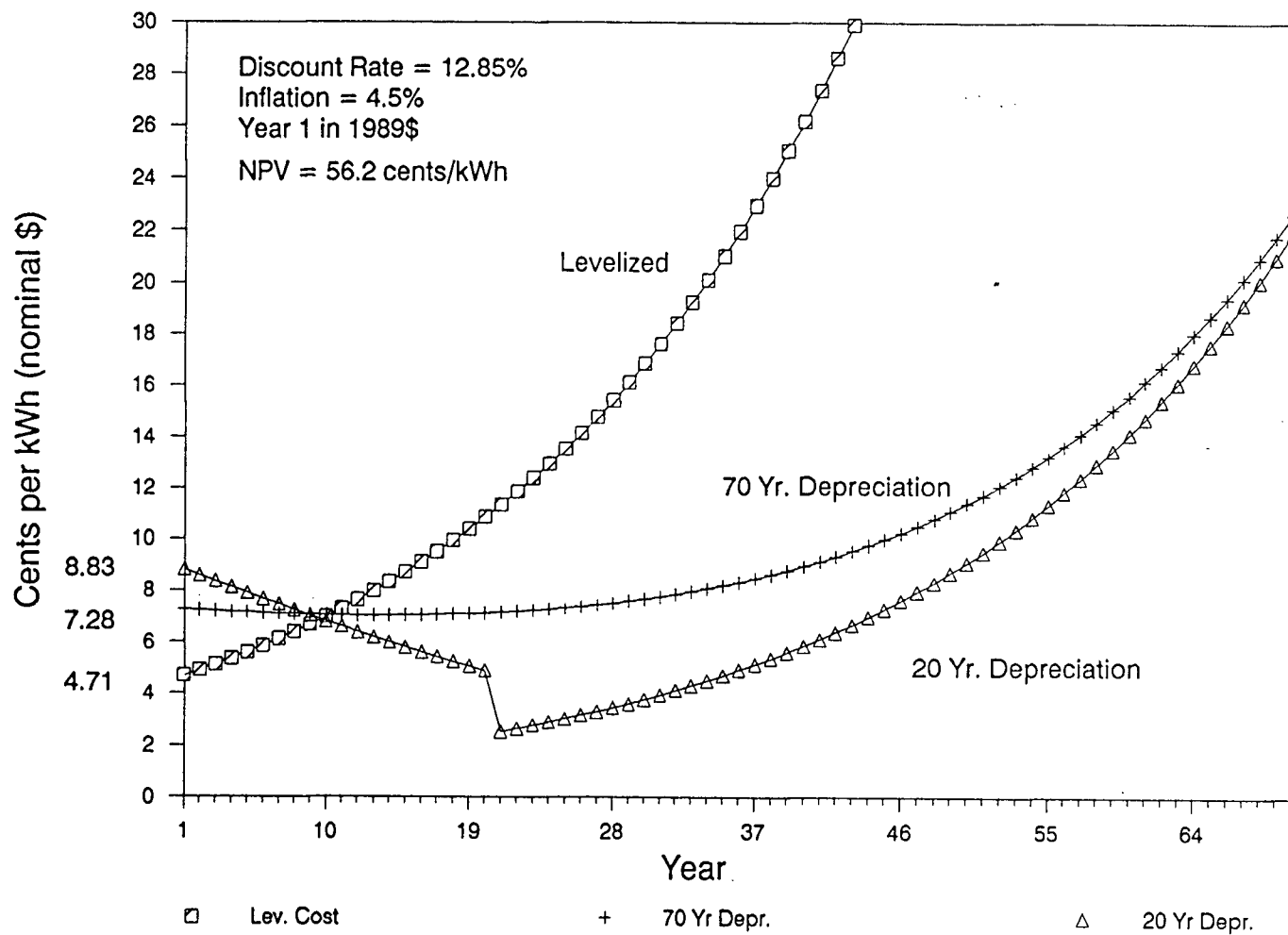


FIGURE 4.6 : Different Accounting Costs for Site C

nominal annual unit energy costs with year 1 in 1989 dollars. All three cash flows have the same Net Present Value (NPV). The calculation of these cash flows uses data from B.C. Hydro's reports "20 Year Resource Plan" (April 1989) and "Value of Electricity" (August 1989) including an assumed discount rate of 12.85% and a long-term, average annual inflation rate of 4.5%.

The 70 and 20-Year Depreciation lines are based on actual expenditure profiles in which a greater proportion of the capital costs would be paid up front. As levelized costs do not represent actual expenditures by the utility, they do not represent costs that are passed onto the ratepayer. Thus, for choosing between different projects, levelized costs may be an appropriate measure, but for setting a purchase rate they are not. I suggest that the 20-Year Depreciation line is the most realistic reflection of Site C's avoided costs for comparison with private sector projects.

#### 4.4 : Suggested Avoided Cost Profile

As discussed earlier, B.C. Hydro presently bases its avoided cost on its short and long-term marginal costs in which the long-term costs are based on the average levelized cost of future projects as shown in Figures 4.1 and 4.7. I propose that, for the purposes of setting a price for independent power purchases, avoided costs be based on short-term marginal costs (STMC) and the cost of the next plant.



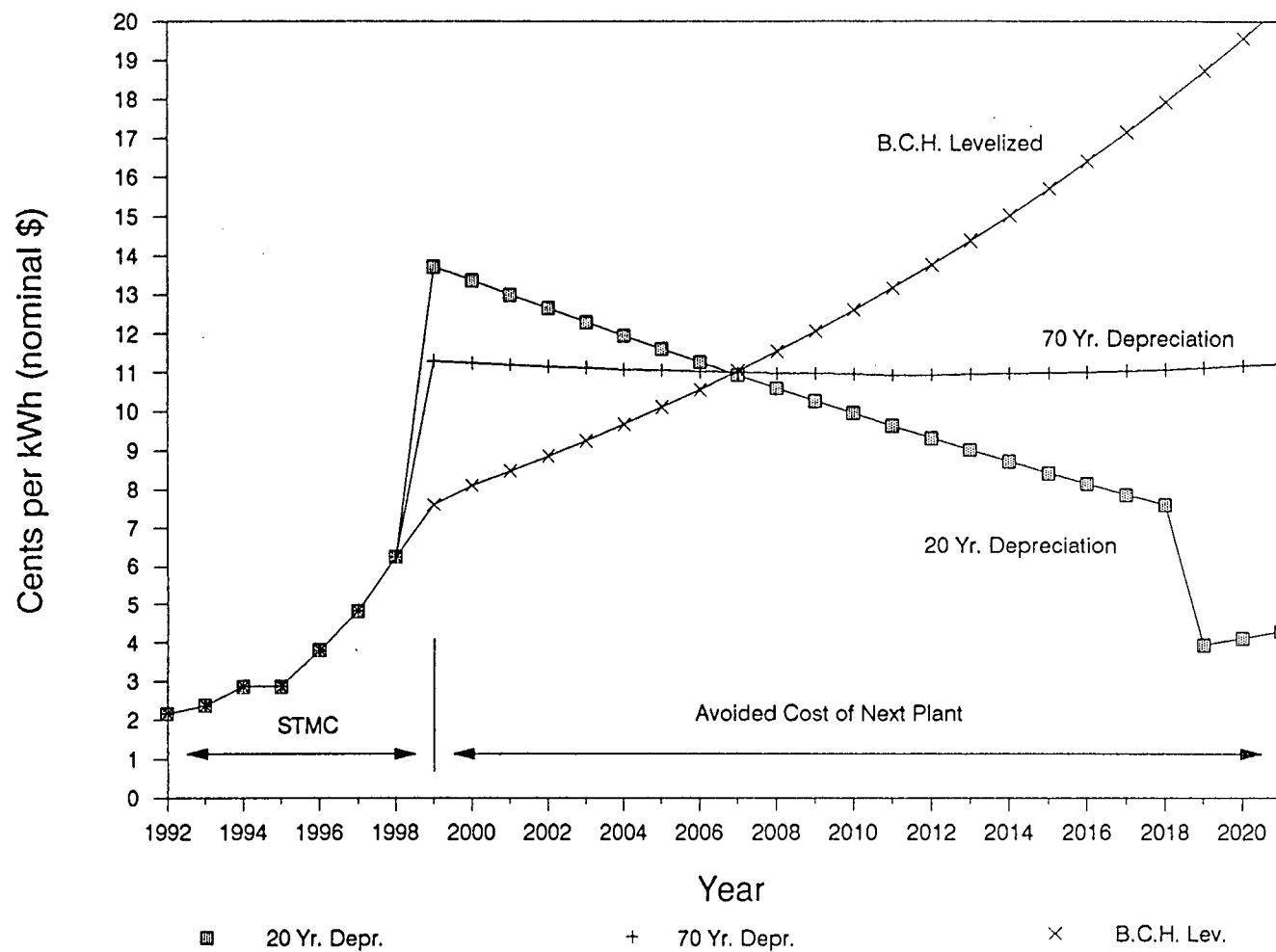


FIGURE 4.7 : Avoided Cost Profiles (1992-2021)

The cost of the next plant should be calculated by depreciating the capital costs over the first 20 years of the plant's life.

An avoided cost profile can then be generated as shown in Figures 4.7 and 4.8. Avoided costs are based on STMC up to 1998 and then jump up to Site C's avoided costs in 1999. This avoided cost profile can be used to set rates for small power projects that come on-line up to the time at which the avoided plant begins operation. When the next major plant finally does come on-line, a new profile would be generated based on the next scheduled plant.

A utility should be willing to pay an IPP a rate that has a NPV equal to or less than their avoided cost stream over the same period. B.C. Hydro has adopted this approach and recently said that the ceiling price to be paid an IPP should be based on the "equivalent present value" of their "avoided costs for the same block of electricity" (B.C. Hydro, Nov. 1989, p.I-3-9). For example, for a 20-year contract starting in 1992, the NPV of the purchase price over the 20-year period would be equal to the NPV of the avoided costs over the same period.

#### 4.5 : Comparison with B.C. Hydro's Offer

As an example, let's look at a project coming on line in 1992, which is the earliest a small hydro plant could be in service if a developer signed a contract today. To keep

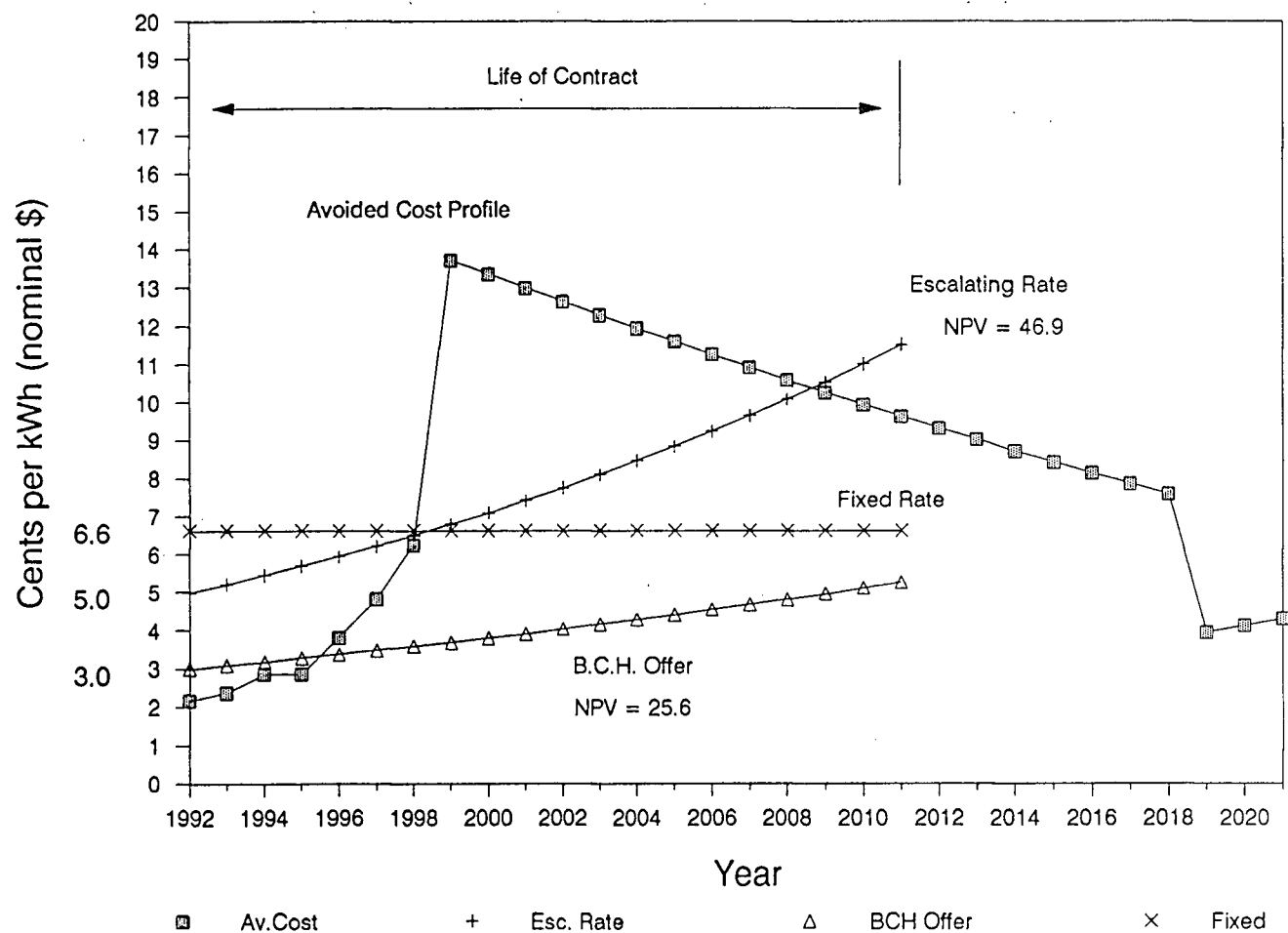


FIGURE 4.8 : 20 Year Purchase Rates Starting in 1992

administrative costs low for both itself and potential developers, B.C. Hydro is offering standard 20 year contracts for projects less than 5 MW. The purchase rate presently being offered a small power producer is 3.0 cents/kWh, escalating at 3% per year, as shown in nominal dollars in Figure 4.8. This is the price for all energy, both firm and secondary.

Over the 20-year life of the contract, the NPV to B.C. Hydro of the purchase price is 25.6 cents per kWh of average annual output compared to a NPV of 46.9 cents/kWh for the avoided cost stream (in 1992 dollars). Thus, the small power producer would only be receiving a little over half of what it would cost B.C. Hydro to produce its own power over the same period (if the utility repaid its capital costs within 20 years as the private producer must).

To make the purchase rate equivalent to the avoided cost rate over the 20 years, it would have to start out at a base rate of 5.0 cents/kWh and escalate at the rate of inflation (assumed to be 4.5%) as shown in Figure 4.8. Alternatively, a fixed rate of 6.6 cents/kWh could be offered. The NPVs to B.C. Hydro of the avoided cost and purchase rate would now be equal. Of course, the rate may have to be adjusted for factors such as firmness and reliability of energy supply and transmission costs, but the general principle still applies.

As shown in Figure 4.8, B.C. Hydro would pay more than its avoided cost for power in the early years of the contract, but would pay considerably less in the later years. Thus, the proposed rate is front-loaded compared to the avoided costs. This proposed rate would allow small hydro developers to pay off their capital costs over the term of the contract.

Using this same technique of matching the NPV of the purchase price to the NPV of the avoided cost stream for the same time period, a purchase rate schedule could be developed as shown in Table 5 in nominal dollars. This rate increases each year up to the time Site C comes on line, at which point new small hydro projects would be receiving a rate, before adjustments, that is equivalent to the full avoided cost of Site C. This ensures that all small hydro projects costing the same or less than Site C are built first, with the effect of pushing Site C as far into the future as possible. The increasing rate also helps to ensure that development is gradual, with lower cost sites being built first.

Table 5 also includes rates based on B.C. Hydro's levelized long-term costs which would be equivalent to their suggested ceiling price for IPP power. These rates are lower than the suggested rates. The 1989 base rate of 3.97 cents/kWh escalating at inflation offered in Ontario is higher than the suggested 1989 rate of 3.72 and considerably higher than what B.C. Hydro would be offering. Alberta's 1990 base rate of 4.64 cents/kWh is also higher than the suggested 1990

rate. In both Ontario and Alberta, however, rates are based on levelized avoided costs, not accounting costs, and their avoided costs could be quite different than B.C. Hydro's. B.C. Hydro's rates are discussed in more detail in the next chapter.

**TABLE 5 : Energy Pricing Rates 1989 - 1999**

(in cents/kWh in nominal dollars)

20 Year Contract Starting in Year	Suggested Schedule (20 yr. Depr. of Avoided Plant's Capital Costs)		Schedule Based on B.C. Hydro's Levelized Long Term Costs	
	Base Rate Esc.@Infl	Fixed Paymt	Base Rate Esc.@Infl	Fixed Paymt
1989	3.72	4.93	3.14	4.16
1990	4.10	5.44	3.46	4.59
1991	4.52	6.00	3.83	5.08
1992	4.99	6.62	4.23	5.62
1993	5.49	7.28	4.68	6.20
1994	6.02	7.99	5.16	6.85
1995	6.58	8.72	5.66	7.51
1996	7.20	9.54	6.23	8.27
1997	7.79	10.34	6.79	9.00
1998	8.35	11.08	7.31	9.69
1999	8.84	11.72	7.75	10.28

Discount Rate = 12.85%, Inflation Rate = 4.5%

## CHAPTER 5 : VALUE OF SMALL HYDRO POWER

### 5.1 : Discussion of B.C. Hydro's Small Hydro Rate Offer

Not only is the value of B.C. Hydro's small hydro energy purchase rate lower than that of the proposed rate based on the methods outlined in Chapter 4, but it is also significantly less than the value of B.C. Hydro's own suggested ceiling price. The net present values of different 20-year energy purchase contracts are compared in Table 6. For projects coming on-line in 1992, the NPV of B.C. Hydro's suggested ceiling prices, based on their levelized long-term costs, is 39.8 cents/kWh, which is 56% higher than the NPV of 25.6 cents/kWh of their small hydro price offer. The question then arises, "What is the basis for the 3.0 cents/kWh offer?"

From discussions with B.C. Hydro representatives, it appears the 3.0 cents/kWh figure is not based on any hard data or rigorous calculations, but rather is an arbitrary number greater than their estimated short-term marginal costs of approximately 2.0 cents/kWh and less than the long-term levelized cost which was about 4.0 cents/kWh when the purchase price was first set. The 3.0 cents/kWh figure was first proposed in 1988 and to date there has been no provision for adjusting it for inflation up to the time the first projects will come on-line or for changes in B.C. Hydro's marginal costs. For example, in April 1989 B.C. Hydro's long-term value of power was stated as 3.8 cents/kWh in 1988 dollars and

in August 1989 it was changed to 5.0 cents/kWh in 1989 dollars. Although there was a 32% increase in the value of energy, no adjustment was made to the small hydro purchase price. The value of this rate is clearly less than B.C. Hydro's present avoided costs for energy.

TABLE 6 : Comparison of Purchase Rates

Net Present Values of 20-year Contracts  
Cents per kWh of Annual Output in Nominal Dollars  
(in Starting Year \$)

Contract Starting in Year	A Proposed Rate	B BCH Ceiling	C BCH Offer	D Firm Energy	E Second. Energy
1989	35.0	29.5	25.6	27.4	13.5
1990	38.6	32.6	25.6	30.1	14.6
1991	42.5	36.0	25.6	33.3	15.8
1992	46.9	39.8	25.6	36.7	17.1
1993	51.6	44.0	25.6	40.5	18.5
1994	56.6	48.5		44.6	20.4
1995	61.8	53.2		48.8	21.9
1996	67.7	58.6		53.6	23.8
1997	73.3	63.8		58.1	25.7
1998	78.6	68.7		62.2	27.4
1999	83.1	72.9		65.6	29.1

A : Proposed Rate based on 20 Yr. depreciation of avoided plant costs

B : Rates based on B.C. Hydro's short and long-term marginal costs, long-term costs are levelized

C : B.C. Hydro's Under 5 MW offer

D : Rates based on B.C. Hydro's value of Firm Energy only

E : Rates based on B.C. Hydro's value of Secondary Energy only

NPV of Ontario offer of 3.97 cents/kWh starting in 1989  
= 37.3

NPV of Alberta offer of 4.64 cents/kWh starting in 1990  
= 43.6



There are several reasons to explain B.C. Hydro's reluctance to pay full avoided cost for small hydro power. First, they believe power from small hydro has little firm capacity and treat it as mostly secondary energy. Second, there is the perception that buying power from small producers is "risky" and the power source is unreliable. Third, they want to pay as little as possible for private power to reduce the cost to the consumer and not allow developers to receive "windfall profits" at the consumers' expense. However, no hard data has been provided to support this corporate stance. I will now examine each of these three points in more detail.

## 5.2 : Firm Capacity of Small Hydro

Most small hydro plants are run-of-the-river plants. In other words, the energy produced from a run-of-the-river plant will fluctuate with streamflow. Energy production will vary with season and the seasonal variation will depend on geographical location. For example, in the south coast region, energy production is greatest during the winter months when much of the precipitation falls as rain. According to Sigma's study, energy production could average in excess of 60% of installed capacity for eight months of the year for this region (Sigma, 1983, p.1-2). This is based on the weighted average output of all sites in the region identified in Sigma's study and assumes that each plant is sized to be at full generation capacity for the mean annual flow of the particular stream. Production falls to about 40%

of installed capacity during the summer months when precipitation is at its annual low. Energy production profiles for various regions in B.C. are shown in Figure A6-2 in Appendix 6.

The production profiles of the north coast and interior regions are different because a greater proportion of the precipitation falls as snow, which in turn affects stream flow patterns. In contrast to the south coast sites, the lowest production rates are in the winter months for these two regions. The impact of spring runoff is reflected in the higher production rates which reach maximum values during June and July. The influence of the spring freshet is dominant in the interior, where many of the sites reach maximum production capacity during the same month (June). The north coast sites attain a second maximum during the late fall when the precipitation has not yet turned to snow. During the winter months, typically December to March, average monthly production will fall to about 25% and 40% of installed capacity for interior and north coast sites respectively.

Thus, small hydro plants will be operating at less than full capacity during significant portions of the year. In its study, Sigma defined a "firmness factor", which is the expected annual energy production of a plant divided by the maximum possible production (installed capacity in kW x 8760 hours/year), and this factor can be estimated for any given site. Figure A6-1 in Appendix 6 shows estimated firmness

factors for different regions in the province. In general, the firmness factor is higher for coastal sites (average value of 0.6) than for the interior sites (average value of 0.5).

In its IPP purchase rate schedule, Ontario Hydro uses a monthly "capacity factor", which is determined by dividing the total kWh delivered in a month by the maximum possible monthly production (maximum monthly kW delivered x the number of hours in the month). Projects with a capacity factor of 65% or more receive full avoided costs while projects with less than 65% receive a rate based on the short-term incremental energy costs.

Note the difference between average output expressed as a percentage of installed capacity and firm energy expressed as a percentage of average output. For example, while the installed capacity of Site C is 900 MW, its average annual output would only be 60% of the maximum possible output or:

$$60\% \times 900 \text{ MW} \times 8760 \text{ hours/year} = 4710 \text{ GWh per year}$$

but its firm annual energy output would be 97% of its average annual output:

$$97\% \times 4710 \text{ GWh per year} = 4570 \text{ GWh per year.}$$

Although the output of many small hydro projects would vary with streamflow, and as a result little or no capacity value would be attributed to their output, there would be some plants with firm capacity and the energy of these plants

should be valued accordingly. Regardless, B.C. Hydro has stated that it "needs energy, not capacity" (B.C. Hydro, Nov. 1989, p.I-3-16) and it is possible to determine the value of the energy component only.

B.C. Hydro has estimated its short-term and long-term values of capacity as 0.1 cents/kWh and 0.5 cents/kWh respectively (see Table 3). Subtracting the capacity values and using only estimated firm energy values for avoided costs, the NPV of a 20-year contract starting in 1992 is 36.7 cents/kWh, still considerably higher than the standard price offer (see Table 6). The NPV of secondary energy over this same time span is 17.1 cents/kWh. If firm energy output was half of average annual output, in other words 50% of the total energy produced in a given year was firm and 50% secondary, the NPV of total energy produced would be 26.9 cents/kWh, just slightly higher than the price offer. Under these conditions, and using B.C. Hydro's levelized cost data, the 3.0 cents/kWh offer might be reasonable. Thus, the 3.0 cents/kWh rate would penalize those small hydro projects with more than 50% of average output as firm energy. In contrast, Site C's firm energy is 97% of the average energy output.

Ken Peterson, B.C. Hydro's Director of Planning, in response to questions about the firm energy capability of small hydro in B.C., stated, "...it's probably well under 50%" (McDonnell, 1990, p.4). Yet, as an example, the average output of B.C. Hydro's 702 kW Clayton Falls plant in Bella

Coola is in excess of 80% of its installed capacity, in contrast to 60% for Site C (McDonnell, 1990, p.4). While the performance of the Clayton Falls plant may not be representative of all small hydro plants, it does demonstrate that small hydro can have firm energy capability meeting or exceeding that of larger scale projects.

B.C. Hydro has also stated in its RFPs that they would prefer projects capable of supplying more than 50% of their total annual energy delivery in the months of November to April, when their electricity demand is highest. As mentioned above, small hydro sites on the south coast would produce a majority of their power during this time period. Thus, B.C. Hydro should be willing to pay more, not less, for power supply that matches their demand.

In its standard contract for projects under 5 MW, B.C. Hydro requires the developer to deliver a minimum amount of energy per year. This amount would be, according to B.C. Hydro's definition, the firm energy capability of the plant. By including this provision in the contract, B.C. Hydro is assuming the plant has firm energy capability and thus, they should be willing to pay full price for this energy.

Thus, there is evidence that small hydro plants have firm energy capability, but how much and what kind would be typical of a small hydro plant are areas that require further study.

### 5.3 : Risk and Reliability

When a utility buys power from an IPP, it does not assume any of the construction or operating risks and it is only required to pay for power produced. However, the utility does run the risks of the project being delayed, abandoned, or not producing energy in the quantity or quality for which it contracted. Some of these risks can be mitigated through contract provisions such as performance guarantees and low flow insurance. The Ontario government, for example, believes the risks of independent power production are manageable and outweighed by the benefits. The Alberta Small Power Inquiry adopted the view that small power projects pose limited risk to the public and the electrical system, and only by encouraging the development of such projects in the near term would they be able to properly assess the impacts of small projects, including risk and reliability, in the longer term. Overall, the utility could reduce its risk exposure for energy production, and this should increase the value of IPP power.

In regard to the risk of a non-utility project not being completed, it is interesting to note that 35,370 MW of coal-fired and 73,130 MW of nuclear power planned by utilities in the U.S. have been cancelled since the passage of PURPA (Meade, Jan. 1989). In 1986, Pacific Gas and Electric, a California utility, reported that firm capacity of non-utility generators had an average capacity factor of 95% as opposed to 60% for the average utility base load plant (Meade, Jan.

1989). Thus, the assertion that independently produced power is less reliable than utility produced power is questionable.

Admittedly, the small hydro resource is unproven, and the question of reliability is a valid one that requires more research. However, from a total system perspective, many small hydro plants may be more reliable than an equivalent large one. For example, if a plant of 5 MW or less did not perform as expected, the effect on the system would be negligible. If, on the other hand, a large 200 or 300 MW project was not completed as planned, the utility might find itself short of power. Because small hydro plants connected to the integrated grid would be spread over a wide geographical area, the chances of more than a few experiencing low flows, operating problems, or routine maintenance at the same time is low. However, low flows in just the Peace River system, for example, would simultaneously affect 35% of B.C. Hydro's capacity. Thus, risk and reliability must be examined from a system perspective as well as on a project-by-project basis.

Asked to indicate the basis for the skepticism of B.C. Hydro as to the reliability of firm energy from small hydro producers, Mr. Peterson responded, "It's primarily a fact that many of these plants are on streams that have no reliable streamflow records." (McDonnell, 1990, P.4) While it is true that with little or no streamflow data the reliability of a small hydro plant can not be proven, it is not true that it

means the plant will be unreliable. It is probably safe to assume hydrological studies would be performed to determine the reliability of streamflows before a developer invested millions of dollars developing a small hydro site.

#### 5.4 : Windfall Profits

The question of windfall profits in the private sector is a contentious issue for a utility to tackle. If a private developer can produce power at or less than a utility's avoided cost and still make a large profit, instead of trying to reduce the price paid to the developer, the utility should perhaps examine its own cost efficiency. B.C. Hydro is not in a position to dictate rates of return to the private sector.

B.C. Hydro does not pay income tax, and on some projects does not pay school tax, on the revenue it earns; private producers do. School taxes alone amount to about 0.5 cents/kWh (McDonnell, 1990, p.3). For a given block of energy, a larger percentage of the revenues accrue to the taxpayer, who is also the ratepayer, from privately produced power than from utility produced power. For example, for a typical IPP project, over a 20-year contract paying 4.0 cents/kWh escalating at inflation, about 28% of the revenues would accrue to the government through various taxes, 25% would go to the banks as interest charges, 31% would go to operating costs and paying off the principal, while the developer would only receive 17% (McDonnell, 1990, p.4). This



corresponds to a return on after-tax income of 15%, assuming no cost overruns, construction delays, or water shortages. Thus, the government and taxpayers appear to be the "windfall" winners. If the plant did not operate as planned, the public is not required to bail out the developer; the developer has assumed much of the risk and, in return, expects compensation. If, however, B.C. Hydro has a cost overrun or builds a plant that is not immediately required, it is the ratepayers who pay.

As well, most Canadian utilities are subsidized in one form or another while IPPs are not (Passmore, 1987, p.14). For example, B.C. Hydro has its loans guaranteed by the provincial government, resulting in slightly lower borrowing rates. Although no money changes hands, there is a cost to the government for assuming this risk (Nickerson, 1989). B.C. Hydro has also received financial contributions from the government in "aid of construction." Thus, given that private producers and utilities are not competing on a "level playing field," it seems only appropriate that IPPs are given the opportunity to earn a healthy profit.

In conclusion, there is no data to support B.C. Hydro's under 5 MW price offer. Although I agree with the concept of a standard price, provisions should be made for:

- escalation of the rate with inflation up to the in-service date of the plant;

- changes in the rate corresponding to changes in the utility's avoided costs;
- standard rate adjustments for firmness, reliability, and risk exposure.

While some projects may lack firm energy and be potentially unreliable, good projects that can demonstrate firm energy and reliability should not be penalized and should be eligible to receive a fair rate for their power.

## CHAPTER 6 : ENERGY PRICING POLICY FOR SMALL HYDRO POWER

### 6.1 : Suggested Policy

From the above general concepts and the experience in the U.S., Ontario, and Alberta, I have developed a suggested general policy for energy purchases from small hydro producers. Small hydro power purchase rates could be set according to the following proposed two-stage process.

#### 6.1.1 : First Stage

In the first stage, the first 10 years or so, the utility would invite proposals from would-be developers and, provided the proposed projects met well-defined financial, technical, and environmental requirements, offer them a standard contract to purchase energy. The 20-year contract term proposed by B.C. Hydro is reasonable and beneficial to both the utility and the developer.

##### (a) Purchase Rate Schedule

A standard rate schedule would be used in the first stage. This schedule would be based on B.C. Hydro's avoided cost profile with the purchase rates having the same Net Present Value as the avoided cost over the 20-year contract. The avoided cost profile would be based on the short-term marginal costs up to the projected in-service date of the next plant. After this point the avoided costs would be based on

the accounting cost of the next plant assuming the capital costs are amortized over the first 20 years of operation.

This rate schedule should clearly set a starting rate for the in-service year, a contract duration, and, if required (see below), an escalation rate.

The schedule would be updated each year on the basis of changes in projected discount and inflation rates, and the timing and costs of the avoided plant. This schedule would be used to establish prices for projects coming on-line up to the in-service year of the avoided plant. After this point a new avoided cost profile would be used based on the new short-term marginal costs and the avoided costs of the next scheduled plant.

Avoided costs, purchase rates, and the methods for determining them should be subject to an on-going or periodic public review by an independent body with the necessary financial and technical resources.

#### (b) Choice of Two Purchase Rates

The purchase rate schedule would offer the choice of two payment schedules: a base rate in the first year of operation escalating at the actual rate of inflation each year thereafter, or a fixed uniform rate over the life of the contract based on an assumed rate of inflation. This gives the developer some flexibility in financing and managing

risks. For example, if the developer felt actual inflation would be higher than that assumed for calculating the fixed rate, he might choose the escalating rate; if he could secure more favorable financing terms with a front-loaded contract, he might choose the fixed rate.

### (c) Rate Adjustments

The rate would be adjusted, by relatively simple, standardized methods, on a project-by-project basis depending on a number of factors including:

- firmness and reliability of power supply (for example, based on annual or monthly firm capacity). It should be possible to adjust this after the plant is in operation based on actual operating performance;
- location of project and associated transmission losses;
- environmental and social impacts;
- risks assumed by private developer including changes in:
  - inflation and interest rates;
  - taxes and water rentals;
  - regulatory and environmental requirements;
  - demand load;
  - climatic events, e.g., low streamflows.

Adjustments for firmness are discussed in more detail in Appendix 6. B.C. Hydro would adjust the rate downwards for risks it was required to assume. Changes in taxes would include the introduction of the federal government's proposed Goods and Services Tax (GST). For risks such as streamflows, the developer may decide to acquire insurance to compensate B.C. Hydro for low water levels, or the developer might be willing to pay penalties for low output as the result of low streamflows.

#### (d) Capacity Requirements

In the first phase, all projects meeting the specified requirements would be accepted. In other words, there would be no capacity cap. However, to prevent the utility and the various government agencies from being swamped with a flood of proposals, some restrictions could be placed on applications such as only two or three from any one developer in the system at one time, or limiting the number or total capacity of applications accepted for review on a monthly or annual basis.

#### 6.1.2 : Second Stage

After 10 years or so (for example, when Site C is on-line), and the IPP industry has established itself, a standard rate schedule would again be used but prices would be based on the market value of electricity, e.g., what it could be bought for from larger IPPs or other utilities. Assuming that a competitive negotiation or bidding process would be in place

for projects over 5 MW, that electrical energy production in Alberta and the U.S. Northwest would undergo further deregulation, and that B.C. Hydro would increase cooperation and integration with adjacent utilities, it should be much easier to establish a market value for electricity in the future. For example, the unadjusted price for under 5 MW projects could be tied to the lowest (or highest) winning or negotiated price from an over 5 MW RFP.

Alternatively, if the industry is competitive enough, a competitive bidding or negotiation process may be set in place, in which the utility would accept the proposals that would provide energy at the lowest cost, up to the total amount required, provided the cost did not exceed the utility's avoided cost. However, because of the expense and time to B.C. Hydro and private developers of negotiating and administering such a process, it would likely not be cost effective for small projects.

At this point a capacity cap may be set each year depending on system load requirements, but this may not be necessary given the relatively small contribution of under 5 MW projects.

## 6.2 : Policy Rationale

The main rationale for this two-stage approach is the persuasive argument put forward by the Independent Power Producers in Ontario, namely that the first aim should be to

develop a viable small hydro industry. Later, when the industry becomes well established, it could be possible to have competitive bidding for sites and contracts, which would ensure fairness, efficiency, and the benefits of rate competition in the long run. As pointed out earlier, it is time consuming and expensive to prepare a competitive proposal for developing a hydro site or negotiate a contract with the utility. These costs can be handled more easily by a company that has already developed a few small hydro plants, since by that stage, it would need to be well organized, well financed and well beyond the level of a "Mom and Pop" operation. But they cannot be easily handled by a small company at its start-up stage.

Another reason for a two-stage process is the view taken by the ERCB and PUC in the Alberta Small Power Inquiry: the best way to determine the capability, impact, and potential contribution of small power producers is to encourage their development in the short-term and review the results at a future date. This process would help answer questions regarding the firm energy capability, reliability, and risk of small power production based on actual operating data rather than conjecture. The projects are small enough that risks to the public and electrical system are minimal during the initial stage and the results of the review could be used to fine tune the second stage process.



To encourage development and get the small hydro industry on a firm financial basis, the utility should be generous in the early stages and offer prices at or close to its avoided costs. This is an accepted standard in Ontario and Alberta and a cornerstone of PURPA legislation in the U.S. The payment of avoided cost allows the utility to exploit all other sources of energy that cost the same or less than the avoided cost alternative. Basing the avoided cost on depreciating the capital costs of the avoided plant over 20 years, the maximum period that would be acceptable for privately owned developments, and using a 20-year contract term ensures that a developer could pay off the capital costs of an economic project within the life of the purchase agreement. This should result in the rapid build-up of a strong, well-financed small hydro industry with a supporting infrastructure of designers, builders, manufacturers, and suppliers that should strongly benefit the provincial economy. This should also lead to the provision of low cost electricity in the future.

Although it appears that many jurisdictions in the U.S. are moving towards a competitive bidding process, the benefits of the standard avoided cost price for the first 10 years of PURPA are clearly visible in the rapid growth of the multi-billion dollar independent power industry. The industry would likely never have developed in a utility controlled market without the PURPA avoided cost legislation. The industry is

now mature enough to continue to prosper under a more competitive environment.

Representatives of B.C. Hydro point to the situation in California where avoided costs dropped and utilities were required to continue to pay PURPA projects higher rates for power the utilities did not necessarily need at that time. However, it should be recognized that many of the projects built under PURPA were powered by renewable resources such as hydro, wind, solar, and geothermal whose output could displace that of polluting, non-renewable thermal plants. It is possible that avoided costs could once more rise dramatically even higher than the rates now being paid under long-term contracts to independent producers. Expensive utility-sponsored nuclear power plants were mothballed or never completed, yet capital costs in some cases were still passed on to consumers for power that will never be produced. Clearly, ratepayers and the rest of California society will benefit in the long run from paying higher rates to PURPA projects in the short run. Thus, paying full avoided costs for independent power has been successful in the "first stage" of development in the U.S. and using California as an example of the dangers of paying full avoided costs is not really a valid argument.

One drawback to paying full avoided cost based on 20-year depreciation of the utility's capital costs is the risk that the plant does not operate for the full 20 years of the

contract and beyond, so the utility does not benefit from the lower energy costs in the future. As well, there has to be incentive for the owner of the plant to maintain the plant in good working order over the term of the contract so that it will continue to operate for more than 20 years. To ensure that they can take advantage of low energy prices after 20 years, B.C. Hydro should have the option to renew the contract at a price reflecting the avoided cost of operation and maintenance only or at the going market rate for power, whichever is less. They may also wish to include an option to purchase the plant for one dollar at the end of the 20-year contract or an option to assume ownership if the plant, once it begins operation, shuts down before the contract ends, or if the owners fail to maintain it to a certain level of quality.

If the utility pays a front-loaded uniform rate based on full avoided cost, calculated using the proposed method, the developer should not require, nor should he receive, any subsidies or tax exemptions.

In the early stage, simplicity is important. Thus, although the "fair" price to be paid for energy should depend on the local conditions and probably should be "custom fitted" through a negotiation process, in practice a standard rate should be offered to all small power producers, with standard adjustments for firmness, location, etc.

A limit on the number of proposals that should be accepted from one group at any one time would be a safeguard against one or two larger groups trying to "corner the market" and would help prevent too many sites being developed at once. Although the aim would be to encourage several strong, capable, well financed groups, no one group should be allowed to dominate.

## CHAPTER 7 : SUMMARY AND CONCLUSIONS

### 7.1 : Conclusions

Although British Columbia has a significant potential small hydro resource and the development of this resource by independent power producers could provide many benefits, in practice there has been very little progress. The major obstacle seems to be the small hydro pricing policy of B.C. Hydro, the provincial electrical utility. Despite its official policy of encouraging independent power and the commitment of the provincial government to private energy development, B.C. Hydro seems to be having difficulty in adjusting from its traditional role as a monolithic monopoly with complete control over power generation, transmission and distribution, to its new role as a competitive producer, purchaser, and manager of energy resources.

The difficulties in getting development going centre around questions of fairness and equity, not technical issues. B.C. Hydro seems to be doing everything possible to obtain contracts for the purchase of electrical energy at minimal cost, with the laudable aim of minimizing the prices they must charge their customers. However, the price they are offering for small hydro power is significantly less than their avoided costs and there is little evidence to justify this rate. I contend that it would be better to offer private power producers a more generous rate in the early stages that

reflects actual avoided costs, to build up the financial and technical capacity of the industry without increasing costs to ratepayers. I believe that in the long term the province would benefit more from a capable, well-financed, competitive private power industry, than from a short-term policy of squeezing small developers and risk underutilizing the resource or losing it altogether.

The policies I have suggested are not intended to be the only or the best solutions but rather to act as a catalyst for further discussion. Some of the present policies seem to have been formulated in a vacuum and the resolution of these problems will only come with more dialogue. B.C. Hydro, the affected government bodies, and representatives from the small hydro industry should sit down and hammer out a policy that is equitable to all parties and that will maximize the benefits of developing the small hydro resource.

## 7.2 : Suggestions for Further Research

There are several areas of small hydro pricing policy in which further research would shed light on some unanswered questions:

- 1) Firm Capacity and Energy capabilities of small hydro plants;
- 2) Risks and Reliability of IPPs in general and small hydro power in particular;
- 3) Competitive Bidding and Negotiation Processes.

Information gained from research into these areas could be used to develop a fair and equitable small hydro energy pricing policy.

Although I just mentioned them in passing, the following policy issues will undoubtedly be factors affecting the future success of small hydro development:

- 4) Site Allocation on Crown land and water licensing implications (who gets the opportunity to develop which sites);
- 5) Environmental Impact of small hydro plants and other resource planning issues;
- 6) Regulatory Process for small hydro projects.

These last three issues are under review at the moment by the Ministry of Energy, Mines, and Petroleum Resources. Although the under-5-MW projects are supposed to have a streamlined regulatory process, indications are that it will become more complicated. Requiring the developer to spend more time and money in the application and approval process will quickly make feasible small hydro projects uneconomic. Further research into these policy issues may assist in determining whether or not the benefits of additional regulation (if there are any) outweigh the costs.

Although most of the problems facing small hydro developers at this time are economic and policy related, technical improvements and innovation will help the industry

survive in the long term. Although not complete, I suggest the following two areas:

- 7) Capital Cost Reductions such as designing for low cost construction and use of alternative low cost materials and equipment;
- 8) Operational Efficiency such as improved intake designs and more efficient turbines and generators.

By reducing capital costs and improving efficiency, small hydro can become more competitive with larger projects and alternative sources of energy.



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## APPENDIX 1

### BACKGROUND ON THE PUBLIC UTILITIES REGULATORY POLICIES ACT (PURPA)

#### PURPA

Prior to the enactment of PURPA, an independent power producer seeking to sell electricity to a utility or directly to industry faced three major obstacles. First, utilities were not required to interconnect with the producer or to purchase that producer's electrical output. Second, even if a utility was willing to purchase electricity, the price offered by the utility might not reflect fair market value. Finally, a small power producer was potentially subject to extensive utility regulation.

PURPA amended the Federal Power Act to reduce or eliminate these and other obstacles to the development of small power projects. In effect, PURPA requires utilities to interconnect with qualifying facilities (QFs) located in their service territories and to purchase power at a price based on the utility's full avoided cost for energy and capacity. PURPA also exempts small power producers (SPPs) from certain federal and state utility regulations. SPPs qualify under PURPA if the project meets specified size, fuel use, and ownership criteria. Cogeneration projects must also meet additional operating and efficiency standards.

#### Legal Challenges

Because of the uncertainties posed to the utility industry by the Public Utilities Regulatory Act (PURPA), the mandate to purchase power from such unproven, untraditional sources of energy as small power producers became the focus of some extensive legal battles in the early years of PURPA implementation. PURPA and FERC's implementation of PURPA have been legally challenged on such issues as infringement on states rights, establishment of avoided costs, interconnection requirements, provision of back-up power, and the definition of a Qualifying Facility (QF). These challenges have produced considerable uncertainty for utilities, project developers, and state utility commissions.

Two court cases challenged the authority of PURPA and FERC's interpretation of the Act. The first case, in Mississippi, raised the question of the constitutionality of PURPA, arguing that PURPA interfered with state regulatory authority. After appealing a decision of a lower court in February 1981 that declared the rules under PURPA

unconstitutional, FERC was successful in having the U.S. Supreme Court uphold PURPA in June 1982.

During this time, another case also threatened the viability of PURPA. A private utility filed a suit challenging FERC's rules on avoided cost and interconnection requirements, arguing that the full avoided cost rate discriminated against the consumer and was therefore in direct conflict with the intent of the legislation (full avoided cost is the cost the utility would incur by purchasing or developing an additional unit of energy and capacity). If the suit was successful, avoided cost rates would be substantially reduced and small power production facilities would be required to undergo costly and lengthy proceedings to achieve interconnection, effectively shutting down many development proposals. State implementation of PURPA slowed considerably during the two years the case was being fought in the courts. However, after overturning a lower court decision, the Supreme Court affirmed FERC's rules in May 1983, marking the end of the major legal challenges to PURPA and allowing final state implementation of the Act's requirements.

While recognizing that a full avoided cost rule would not lower rates to consumers, the court noted in this case that ratepayers and the nation would benefit through decreased reliance on scarce fossil fuels and more efficient use of energy. The court also found that, in regard to FERC's interconnection rules, requiring small power producers to undergo the same regulatory process as utilities would be time consuming, expensive and non-productive.

In May 1983, another challenge came from a coalition of environmental groups claiming that FERC had not considered the environmental impact of awarding QF status to hydropower projects requiring new dams. This action led to the passage of the Electric Consumers Protection Act (EPCA) in 1986 which put constraints on hydro projects by imposing a moratorium on PURPA benefits to facilities requiring construction of a new dam.

In 1988, FERC invalidated New York's 6 cents/kWh avoided cost. FERC found that this minimum price for purchasing power, which had been set to encourage development, was improperly established at a level higher than the purchasing utility's avoided cost.

### The Future of PURPA

In the words of Martha Hesse, chairman of FERC, "clearly, PURPA...is here to stay. PURPA has evolved into something far beyond the expectations of its creators...it has outgrown the role of a limited energy conservation of program. Now PURPA needs to be updated to reflect what we have learned from the

experience" (Hesse, July 1987, and October, 1988). Thus, PURPA is in a state of transition. Some of the issues to be addressed by FERC and the U.S. Congress include:

- bidding and competitive bidding procedures and the question of requiring utilities to bid;
- allowing utilities to compete with QFs;
- relaxing the regulatory burden of independent generators who do not meet the QF criteria;
- increased transmission grid access;
- regulatory reform and deregulation of the electrical generation industry.

In 1988, in an effort to increase competition in the electric power generation market, FERC issued Notices of Proposed Rulemakings (NOPRs) for changes to PURPA on three main issues. These were: guidelines for administratively determining full avoided costs, regulations governing competitive bidding programs, and rules for establishing Independent Power Production facilities (IPPs) which are not subject to PURPA fuel and efficiency restrictions. But, because of the go-slow approach urged by Congress and the resignation of Chairman Hesse in October 1989, FERC still has not taken the long-expected action to make changes to PURPA rules. FERC is expected to continue to move slowly until the new chairman has time to develop priorities for the agency. Moves to modify the Public Utilities Holding Act (PUCHA) to allow the construction of power plants without the restrictions of PURPA are presently stalled in Congress. Following reports released by the Office of Technology Assessment (Electric Power Wheeling and Dealing) and FERC (Electricity Transmission: Realities, Theory, and Policy Alternatives) in 1989, industry representatives and regulators are debating increased access to the transmission grid.

Thus, there will certainly be changes made to PURPA and other related regulatory legislation, but what these changes will be and what kind of effect they will have remains to be seen. However, there is strong support to make the electrical generation industry more competitive and less regulated.

Sources: Eden, 1985; Hess, 1987 and 1988; Marier, Nov. 1989; Stoiaken, 1988; WSEO, 1989.

## APPENDIX 2

### ONTARIO HYDRO'S SMALL POWER PURCHASE RATES

There are four options for projects with capacities up to 5 MW:

#### 1) Standard Energy Rate

- (a) Capacity factor (CF) of 65% or greater: 3.97 cents/kWh escalated each year at the Ontario Consumer Price Index (CPI) for up to 10 years from the in-service date. Thereafter, the base rate is renegotiated. This rate is presently based on 85% of Hydro's accounting costs for power, but when avoided costs exceed 85% of the accounting cost (1991), this rate will be based on avoided costs.
- (b) CF of less than 65%: 2.54 cents/kWh reviewed annually relative to Hydro's short term incremental energy costs. This rate reflects the short term incremental energy costs to Hydro.
- (c) CF of less than 75% but greater than 50% (new hydro projects only): 3.97 to 2.54 cents/kWh based on sliding scale.
- (d) CF of less than 50% (new hydro projects only): 2.54 cents/kWh.

#### 2) Ten year Fixed Rate for New Renewable Resource Projects

- (a) CF of 65% or greater: 4.94 cents/kWh for 10 years for projects coming into service in 1989.
- (b) CF of less than 65%: 2.54 cents/kWh reviewed annually relative to short term incremental energy costs.
- (c) CF of less than 65% but greater than 50% (hydro projects only): 3.40 to 2.54 cents/kWh based on sliding scale.
- (d) CF of less than 50% (hydro projects only): 2.54 cents/kWh.

### 3) Time Differentiated Rates

- (a) Peak Hours: 5.87 (Winter) and 5.28 (Summer) cents/kWh escalated annually at CPI for up to 10 years.
- (b) Off-Peak Hours: 2.50 (Winter) and 1.72 (Summer) cents/kWh escalated annually at CPI for up to 10 years.

### 4) Ten Year Time Differentiated Fixed Rate for New Renewable Resource Projects

- (a) Peak Hours: 6.96 (Winter) and 6.25 (Summer) cents/kWh for 10 years.
- (b) Off-Peak Hours: 2.97 (Winter) and 2.04 (Summer) cents/kWh for 10 years.

### Definitions:

- Monthly capacity factor is determined by dividing total kWh delivered in a month by the product of the maximum monthly kW delivered and the number of hours in the month.
- Peak Hours are 7 a.m. to 11 p.m. weekdays; Off-Peak Hours are 11 p.m. to 7 a.m. weekdays, plus all weekends and public holidays.
- Winter is defined as October through March; Summer is defined as April through September.



### APPENDIX 3

#### ALBERTA SMALL POWER INQUIRY

The objective of the Public Utilities Board (PUB) and the Energy Resources Conservation Board (ERCB) was "to inquire into, report upon, and make such recommendations as necessary or advisable respecting electricity generation by small power generators in Alberta". The Boards were specifically asked to determine:

- the size and type of generators that should be classified as small power generators;
- the number, types, and capacities of small power generators and their total capacity that could be interconnected without negatively affecting the reliability of the system or the cost of electricity;
- the principles and methods which should apply to the setting of a price or prices paid by the utilities for electricity produced by small power generators.

#### Recommendations of the Boards

The Boards' recommended that:

- 1) the Alberta Government allow and facilitate the production of electricity by independent producers in parallel with the Alberta interconnected system (AIS);
- 2) all power producers with generating capacities of 2.5 MW or less at one site be classed as small power producers (SPPs);
- 3) initially, a maximum of 100 MW of small power capacity be interconnected, since this would not negatively impact the reliability of the system nor would it substantially increase the cost of electricity to the consumer;
- 4) the prices paid to SPPs by utilities should be based on utility long-term avoided costs in order to ensure that prices to consumers would not increase. The prices should vary according to the reliability, availability, term of contract, and commencement of contract;
- 5) SPPs should be exempted from the provisions of the Public Utilities Board Act and the Electric Energy Act subject to obtaining the consent of the ERCB prior to constructing or operating a small power facility.

Avoided Cost - The only costs which can be avoided from now until the mid-1990's are variable fuel, operating, and maintenance costs. Commencing in about 1995, it may be possible to defer certain capital additions and thus avoid the attendant capital and fixed fuel, operating, and maintenance costs.

Purchase Price - In order that electricity prices to consumers are not increased, the prices paid by utilities for small power production should reflect the costs which the utilities would avoid over the life of the contract with the small power producer. This can be achieved by determining prices based on (a) the year-by-year avoided costs or (b) a levelized price that has the same NPV as discounting the long-run avoided costs over the length of the contract.

Contracts - Standard contracts should be developed by the utilities, in consultation with the Small Power Producers Association, for as-available (secondary) and firm power purchases.

The above recommendations should be reviewed in 1994 or when 100 MW of small power has been interconnected, whichever occurs first.

#### Views of the Boards on Related Matters:

- 1) Small power projects pose limited liability of financial risk to the public and should be subject to a streamlined regulatory process.
- 2) No subsidies, by way of incentive prices and resulting extra cost to consumers, should be given to SPPs (but this does not preclude any direct assistance that the government might deem prudent as initial encouragement to a new industry).
- 3) Socioeconomic benefits associated with small power projects, or a small power industry, should not be a consideration in the derivation of buyback rates. Any such benefits can be more appropriately recognized through direct government initiatives such as taxes or grants rather than through increasing power rates to the consumer.
- 4) Electric utilities can make a significant contribution to the development of a small power industry and should not be denied access to that industry.
- 5) 2.5 MW is a practical upper limit to cover the majority of small power projects and small enough to be technically flexible and easily accommodated by the electric distribution systems, with the ability to

connect such facilities with little impact to its distribution system.

#### 6) Avoided Costs

Avoided costs rather than historic costs should be used as the basis for determining prices since this would better reflect the estimated value of capacity and energy when the SPPs would be added to the system. SPPs should receive fair value for the energy and capacity they would provide to the system as a substitute for what the utilities would likely impose in their absence. Long-term avoided costs should be used as the starting point to determine prices for small power generation.

The Board examined three methods for determining avoided costs: Differential Revenue Requirements (DRR), Fuel Offset, and Proxy Plant methods. The first two are detailed methods of estimating long-term avoided cost that use complex computer models and educated assumptions. The third is a less rigorous but simplified method that utilizes information that is readily available. The method chosen must be simple enough so that results could be easily verified and understood and still be fair to all parties; thus there will be a trade-off between accuracy and simplicity. The Proxy Plant Method meets most of the requirements and was accepted for purposes of determining avoided costs.

Some of the assumptions made in determining avoided costs were:

- avoided costs should be calculated net of income taxes rebates;
- as a result of connecting SPPs to the system, losses on the transmission system would be reduced, and avoidable transmission losses should be included;
- utility property taxes, insurance, and interim replacements are avoidable costs;
- assumed inflation = 4.5%, discount rate = 11.5%, real discount rate = 6.7%;
- annual depreciation rate =  $1/(\text{useful life})$ .

Based on the costs of the Proxy Plant and the above assumptions, annual levelized costs were calculated for the avoided plant. These costs rise at the rate of inflation over the life of the plant. Avoided costs were then set as:

- marginal energy costs (variable fuel, operating, and maintenance costs) up to expected in-service date of proxy plant (capacity addition);
- levelized avoided cost of the Proxy Plant thereafter.

#### 7) Purchase Price

In order to ensure that electricity prices to consumers do not increase, the prices that utilities pay for small power production should not exceed the cost that the utility avoids over the life of the contract with an SPP.

If prices were determined based on the year-by-year avoided costs, most small power projects would be uneconomic, as financing of such projects is contingent on a fixed/level price schedule. Instead, the utility should provide small power capacity payments in advance of when that capacity is actually required; this can be achieved by determining a levelized price (fixed price) which, when discounted, equates to the long-run avoided costs over the term of each contract.

Those SPPs which cannot provide firm power should have their capacity prorated downward in accordance with their expected capacity factor relative to the capacity factor of the proxy unit; however, initially the same price will apply to both firm and as-available (secondary) power; it may be possible that some adjustment and a distinction in prices between as-available and firm power may be necessary when the program is reviewed.

Prices should be developed for 10, 15, 20-year contracts; prices would vary with the term of contract and its commencement date (see Table A3-1 which shows recommended levelized prices). These prices would remain fixed for the duration of each contract commenced during that period.

- 8) The regulatory process applicable to SPPs should be simplified, streamlined and expedited in order to reduce the time, effort, and cost associated with obtaining regulatory approvals, and in doing so, some degree of control must be maintained respecting environmental and safety matters.

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TABLE A3-1 : Purchase Prices for Firm and Secondary Power as Recommended by the Alberta Small Power Inquiry

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For Contract Starting in Year	Fixed Price in cents/kWh for Contract Duration of		
	10 Years	15 Years	20 Years
1989	1.8	2.3	2.7
1990	2.1	2.6	3.0
1991	2.5	3.0	3.4
1992	2.9	3.4	3.8
1993	3.4	3.9	4.2
1994	3.9	4.4	4.7

Source: "Small Power Inquiry", ERCB and PUC of Alberta, Feb. 1988, Table 4-1, p. 15.

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Government Implementation of the Boards' Recommendations:

In response to the report, the Alberta government announced the "Small Power Research and Development Program" in June 1988 and updated it in November 1989. The major differences between the Boards' recommendations and the government program were:

- the 100 MW total capacity cap was raised to 125 MW;
- the program was limited to renewable resources projects only;
- utilities and their subsidiaries are not eligible to participate in the program;
- the purchase price was increased (5.2 cents/kWh until 1995 and 6.0 cents/kWh thereafter), effectively bringing the long term price forward to the present;
- in limiting the program to renewable resources and increasing the recommended purchase price, the government considered the environmental benefits of renewables.

It is also interesting to note that the provincial government assisted the Small Power Producers Association with a grant of \$100,000, matched by the federal government, to assist them in making a full representation to the hearing.

## APPENDIX 4

### B.C. HYDRO'S IPP ENERGY PURCHASE POLICY

There are four areas of interest to the private power developer:

- 1) Domestic Use
  - a) Non-Integrated area;
  - b) Integrated system from projects under 5 MW;
  - c) Integrated system from projects over 5 MW;
- 2) Export Market.

This includes electricity released by load displacement.

#### B.C. Hydro's IPP Policy Statement:

"In its effort to achieve the most economic supply of electricity, B.C. Hydro (BCH) is turning to IPPs for a portion of its electricity supply requirements. Cost effective independent power production should allow deferral of larger, potentially more expensive projects on the integrated system."

"Independent Power Production is defined as electricity generated by an independent or privately-owned facility, which is connected to the BCH system."

"To pursue electricity purchases and assist IPPs, BCH will (among other things):

- expedite the process of reaching an agreement for the purchase of electricity;
- consider special arrangements for projects demonstrating new technology or promising significant environmental, social or economic benefit to the Province."

"For projects less than 5 MW, BCH will invite proposals for the supply of electricity as new generation is required in the spring of each year for a predetermined maximum total."

#### Policy Highlights:

- to minimize administration and transaction costs and to facilitate the development of independent power projects under 5 MW capacity, standard conditions including the purchase price will apply; this rate will be announced by BCH at the time of the RFP issue and will be subject to escalation

- the purchase price will be set annually at a value that reflects BCH's incremental cost of electricity.
- a purchase agreement will be entered into on a first come, first serve basis until the aggregate of the agreement is approximately the predetermined maximum total
- BCH will supply information on transmission circuits in the proximity of the proposed project and preliminary estimate of connection costs
- BCH would prefer projects capable of supplying more than 50% of their total annual energy delivery in the months of November to April
- proposed projects are expected to be in-service within 2 years after the purchase agreement is signed

#### Application Procedure

- proposals are first checked for completeness and registered for first come/first served consideration
- proposals are given a Technical Review: proposals are reviewed for safety, protection, system compatibility, reliability, and quality of electricity supply
- if accepted, BCH will issue a Project Connection Requirements Summary and an Electricity Purchase Agreement (EPA)
- at this point, the Project Sponsor may initiate further discussion with BCH on either the connection requirements or the EPA; once the EPA is signed and returned to BCH, the project is accepted as part of the total block requirement

#### Electricity Purchase Agreement (EPA) - highlights

- 20 year term initially, option to renew each year after, unless terminated upon 6 months notice by either party
- the project is required to provide a minimum amount of kWh per year
- BCH may terminate the agreement without notice if proposed in-service date is not achieved
- the purchase rate is currently 3 cents/kWh for first year, plus adjustments each year = CPI for Vancouver, but not exceeding +3%/yr
- to qualify for a EPA with BCH, the IPP must be willing and able to (among other things):

- 1) Demonstrate, through previous experience and/or performance guarantees, an ability to design, finance, construct, and operate the proposed project; BCH will engage independent financial services to assess the credit worthiness and financial state of the IPP, and to analyze the benefits to BCH of the proposed project
- 2) Meet the standards for electricity quality, reliability of supply, and safety, and be compatible with the BCH system
- 3) Pay for interconnection costs and required modifications to existing BCH facilities
- 4) Pay fee(s) to BCH to assist in defraying its costs of evaluating the proposal
- 5) Obtain all necessary approvals, licences, and permits necessary and sufficient for the construction and operation of his plant and to comply with all regulatory requirements including all exemptions or approvals under the B.C. Utilities Commission Act
- 6) Prove the land is available for the proposed use

#### Projects Greater than 5 MW - Major Differences and Features

- proposals will be called, as required, for purchases of electricity for the integrated system from projects greater than 5 MW through a public RFP process; BCH will purchase electricity from these projects provided that the quality is acceptable and the cost to BCH is lower than the cost of other alternatives available
- the electricity purchase price and other conditions for these projects will be negotiated and BCH will seek financial arrangements which optimize benefits to BCH and its ratepayers
- BCH will consider alternative price structures and/or financing arrangements, with appropriate guarantees, to assist developments greater than 5 MW supplying the integrated system
- BCH intends to issue RFPs for blocks of firm electricity supply and load displacement as required (usually in the fall)
- BCH will commence negotiations with the potential suppliers that submit the best proposals

#### Competitive Negotiation Process:

- price is important, but there are other key factors to be considered



- process is iterative; initial screening will establish preferred candidates on a short list, on the basis of financial viability, technical merit, the candidate's qualifications, and the quantity of electricity being offered, as well as price
- simultaneous negotiations will then commence with those on the short list to further refine and adjust the proposals, and to develop a mutually acceptable price and contract between the IPP and BCH
- where there is no agreement on price, the IPP will be dropped from the short list, and the next most meritorious IPP, not on the short list, will be admitted into the competitive negotiation process
- this process will continue until BCH enters into an agreement to purchase the required amount of electricity and/or load displacement at acceptable prices and under satisfactory conditions

#### Purchase Price and Financing Arrangements

- the intent is to negotiate a price that provides the lowest cost to BCH ratepayers and reflects the values of firm and secondary energy
- Factors affecting price include:
  - dependability of annual energy deliveries
  - reliability of supply
  - duration of supply
  - dispatchability
  - impact on the transmission and distribution system, e.g., proximity to the Lower Mainland
- BCH may negotiate financing arrangements that are of benefit to both the respondent and BCH; the purpose is to make the project economic and financeable for the respondent without imposing undue risk on BCH
- financing arrangements will be evaluated on a present worth basis and would be acceptable only if they cause no reduction in BCH's net benefit from the project
- preference will be given to projects entailing the least amount of financial and operational risk to BCH; performance guarantees may be required to reduce risk to BCH, both front-end and operational risk

Source: All information taken from B.C. Hydro's "Purchase of Electricity (Projects Under 5 MW) for B.C. Hydro's Integrated System" (May 1989), "Purchase of Electricity and Load Displacement for the Integrated System from Projects Greater than 5 MW and Projects Under 5 MW" (December 1988).

## APPENDIX 5

### ENERGY COSTS OF SITE C

The energy costs of B.C. Hydro's Site C hydroelectric project used in Table 3 and Figures 4.2 to 4.5 were calculated as shown below. All data was taken from B.C. Hydro's reports entitled "1989 20 Year Resource Plan" (April 1989), "Value of Electricity" (August 1989), and "Guidelines for Pricing of Resource Acquisitions" (November 1989). Figures are in millions of dollars unless noted otherwise.

#### A. Discount and Inflation Rates:

Nominal Discount Rate, $r$	= 12.85%
Net Discount Rate, $r^*$	= 8.0%
General Annual Inflation Rate, $i$	= 4.5%
Annual Inflation Rate of Electricity, $e$	= 3.0% (1989-1998)
	= 4.5% (1999 onwards)
Inflation Rate, 1988 to 1989	= 5.0%

#### B. Assumptions:

- Site C comes on-line in 1999 after 7 year construction period beginning in 1992; Project Life = 70 years.
- Annual Fixed Costs escalate at general rate of inflation.
- Annual Variable Costs (Water Rental Rates) escalate at same rate as price of electricity.
- Project operates at full capacity first year of operation.
- Construction Costs are a series of equal annual payments and project is 100% debt financed.
- Annual Fixed, Variable, and Construction Costs are incurred at year end and do not escalate with inflation during the year, i.e., fixed annual costs of \$33 M in 1989 are incurred at year end 1989 at \$33 M, not  $33 \times 1.045 = \$34.5$  M.

#### C. Costs in 1989 Dollars:

- |                                                                                                         |             |
|---------------------------------------------------------------------------------------------------------|-------------|
| 1) Capital Costs                                                                                        | = \$1,826.0 |
| - includes transmission cost but not interest and inflation during construction and corporate overhead. |             |
| 2) Corporate Overhead (@ 3% of Capital Cost)                                                            | = \$54.8    |
| 3) Total Capital Cost = 1826.0 + 54.8                                                                   | = \$1,880.7 |

- 4) Annual Fixed Cost (@ 1.81% of Capital Cost) = \$33.0  
     - includes operation and maintenance, administration, grants and taxes, and interim replacement.
- 5) Annual Variable Costs (@ 0.4 cents/kWh) = \$18.8  
     - consists of energy portion of water rental fees, average annual energy output = 4710 GWh.

D. Calculation of Construction Costs :

- 6) Present Value of Annuity, discounted at  $r^*$ , over 7 years,  
     (P/A,  $r^*$ , N=7) = 5.2081
- 7) Annual Construction Cost = 1880.7/7 = \$268.7
- 8) Total Capital Cost including interest and inflation at end of 7 year construction period  
     =  $268.7 \times (P/A, r^*, N=7)/(1+i) \times (1+i)^7$   
     =  $268.7 \times (5.2081/1.045) \times (1.1285)^7$  = \$3,121.0
- 9) Total Capital Cost in 1989 dollars  
     =  $3121.0/(1+i)^7 = 3121.0/(1.045)^7$  = \$2,293.4
- 10) Total Capital Cost in 1999 Dollars = \$3,561.6

Note: This figure compares to figures reported in various newspaper reports of \$3.0 to \$3.5 billion for Site C.

E. Adjustment of Annual Variable Costs :

- 11) Annual Variable Costs in 1999 Dollars  
     =  $18.8 \times (1+e)^9 \times (1+i)$   
     =  $18.8 \times (1.03)^9 \times (1.045)$  = \$25.7
- 12) Adjusted Annual Variable Costs in 1989 Dollars  
     - this figure now can be escalated at just the general rate of inflation for ease of calculation.  
     =  $25.7/(1+i)^{10} = 25.7/(1.045)^{10}$  = \$16.5

F. Calculation of Levelized Unit Energy Cost

- 13) Present Value of Annuity, discounted at  $r^*$ , over 70 years,  
     (P/A,  $r^*$ , N=70) = 12.4574
- 14) Levelized Annual Cost  
     =  $33.0 + 16.5 + [2293.4 \times (1+i)/(P/A, r^*, N=70)] = \$241.9$

15) Levelized Unit Energy Cost

$$= 241.9 \times 100/4710$$

$$= 5.14 \text{ cents/kWh}$$

G. Adjustment of Capital Costs

B.C. Hydro states their levelized unit energy cost for Site C as 4.71 cents/kWh in 1989 dollars, lower than the figure of 5.14 that I calculated above. I have assumed much of the difference between the two figures can be attributed to the calculation of interest and inflation during construction as this is where most of the uncertainty in my calculations lies. I have adjusted the Total Capital Costs as follows in order that the unit energy cost is equal to 4.71 cents/kWh.

16) Net Present Value of 4.71 cents/kWh

$$= 4.71 \times 4710/100 \times (P/A, r^*, N=70)/(1+i)$$

$$= 4.71 \times 4710/100 \times (12.4574/1.045) = \$2,644.5$$

17) Total Capital Cost in 1989 Dollars

$$= 2644.5 - (33.0+16.5) \times (12.4574/1.045) = \$2,053.4$$

Note: This figure is equivalent to \$3.2 billion in 1999 dollars, still within the reported \$3.0 to \$3.5 billion range.

H. Summary of Total Costs in 1989 Dollars:

$$\text{Total Capital Costs} = \$2,053.4$$

$$\text{Annual Fixed Costs} = \$33.0$$

$$\text{Annual Variable Costs} = \$16.5$$

$$\text{Levelized Unit Energy Cost} = 4.71 \text{ cents/kWh}$$

## APPENDIX 6

### PRICE ADJUSTMENT FOR FIRM ENERGY

An adjustment to the rate schedule for firmness of power could be done in one of two ways:

- 1) using two power rates: one for firm energy and another for secondary;
- 2) adjusting the rate for all power.

This adjustment could be related to the firmness (or capacity factor) of the avoided plant. For Site C, firm annual energy is about 60% of its maximum possible output, and 97% of its average annual output. The minimum monthly firmness factor or the minimum annual factor could be used.

Sigma defined a "firmness factor" as the expected annual energy production of a plant divided by the maximum possible production (installed capacity in kW x 8760 hours/year), and this factor can be estimated for any given site (Sigma's Figure 5.3, reproduced here, shows estimated firmness factors for different regions in the province). The firmness factor would be numerically equal to the load factor for sites supplying power to an unlimited demand such as supplying to the integrated grid. The system load factor may be substituted for the firmness factor for off-grid sites with limited load when the plant output is limited by lack of water or lack of power demand. In general, the firmness factor is higher for coastal sites (average value of 0.6) than for the interior sites (average value of 0.5).

Ontario Hydro uses a monthly "capacity factor", which is determined by dividing the total kWh delivered in a month by the maximum possible monthly production (maximum monthly kW delivered x the number of hours in the month). Projects with a capacity factor of 65% or more receive full avoided costs while projects with less than 65% receive a rate based on the short term incremental energy costs (see Appendix 2).

The Alberta Small Power Inquiry suggested those projects which cannot provide firm power should have their capacity prorated downward in accordance with their expected capacity factor relative to a standard capacity factor (in their case the capacity factor of the avoided proxy unit).

Some factors to consider include:

- the long term levelized value of energy is 4.5 cents/kWh while the value of capacity is only 0.5

cents/kWh. Thus small producers should not be excessively penalized for providing mostly energy value, and at the same time it should be recognized that some small producers will have some firm capacity.

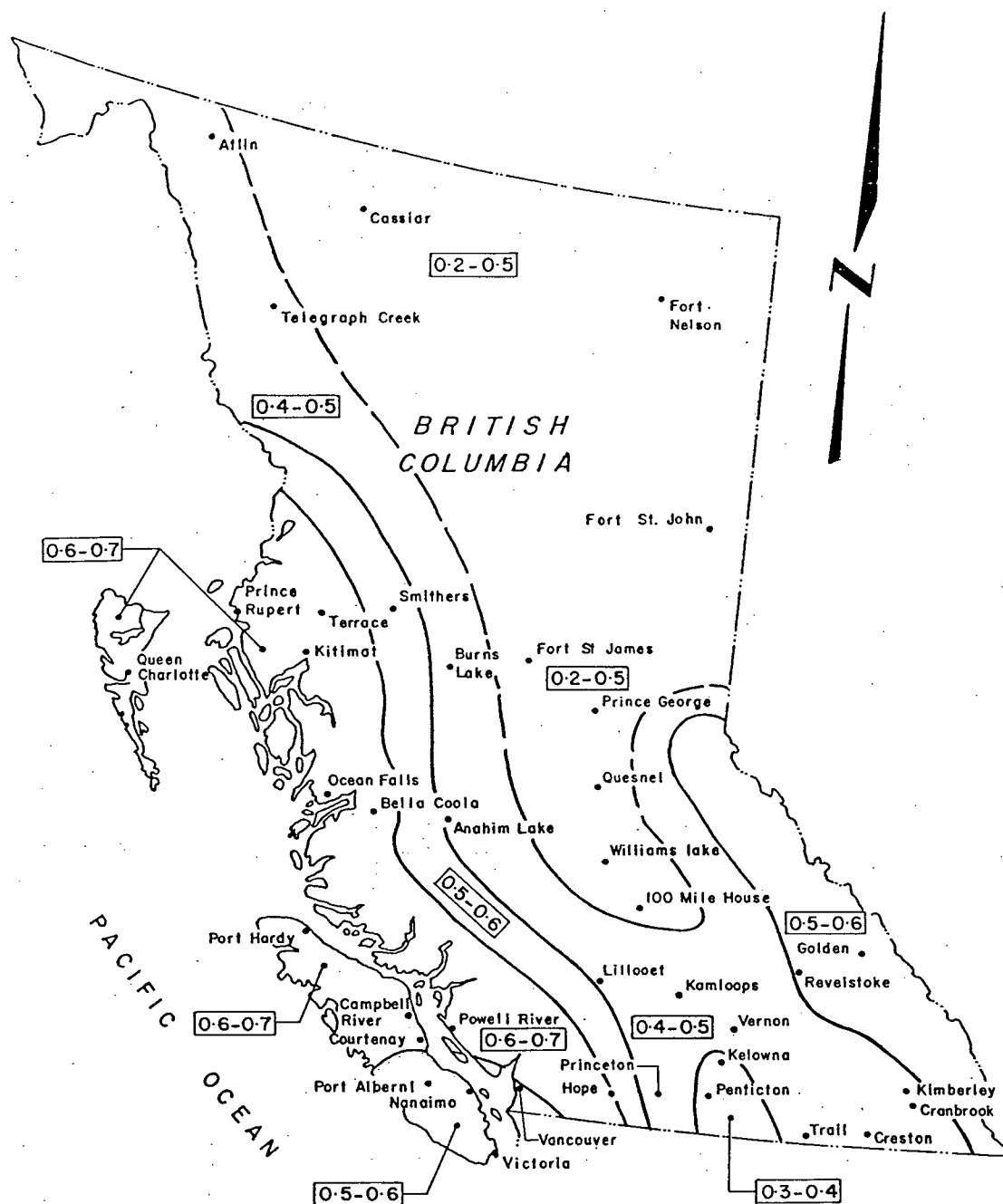
- the energy production profile (the seasonal variation in energy production) of small hydro plants should be considered when making adjustments to the base rate. For example, in the south coast region, energy production is greatest during the winter months when electrical demand is also generally the highest. B.C. Hydro has stated that they would prefer projects capable of supplying more than 50% of their total annual energy delivery in the months of November to April. Thus, south coast sites should receive a slightly higher rate.

As an example of using two power rates, the minimum monthly energy output from a small hydro plant would receive the full unadjusted rate based on the value of firm energy. All energy produced in excess of this amount would receive an adjusted rate based on secondary energy value.

Alternatively, using an adjustable standard rate, all power produced from one project would receive the same adjusted rate. The standard rate would be adjusted based on the firm energy capability of the plant. The firm energy capability could be determined for the specific plant or, more simply, the average firmness capacity of the region where the project is located (e.g., south coast, north coast, interior) could be applied.

If the first method was adopted, the firm energy capability of a site could initially be estimated based on the developer's hydrological evaluation. At the end of each year (or month), there could be an adjustment. If minimum monthly output was greater than originally estimated, the developer would receive a bonus equal to the difference between firm and secondary energy based rates. If, on the other hand, the minimum monthly output was less, the developer would be required to pay a penalty (deducted from the next year's payments). B.C. Hydro could have the option to use the developers estimate for the entire contract (if B.C. Hydro thought the estimate was low) or use the bonus/penalty system (if they thought the estimate was too high). If this option was solely B.C. Hydro's, developers would have a great incentive to accurately estimate the firm energy capabilities of their plant.

The advantage of the second method lies in its simplicity, which is an important consideration when devising a purchase policy.

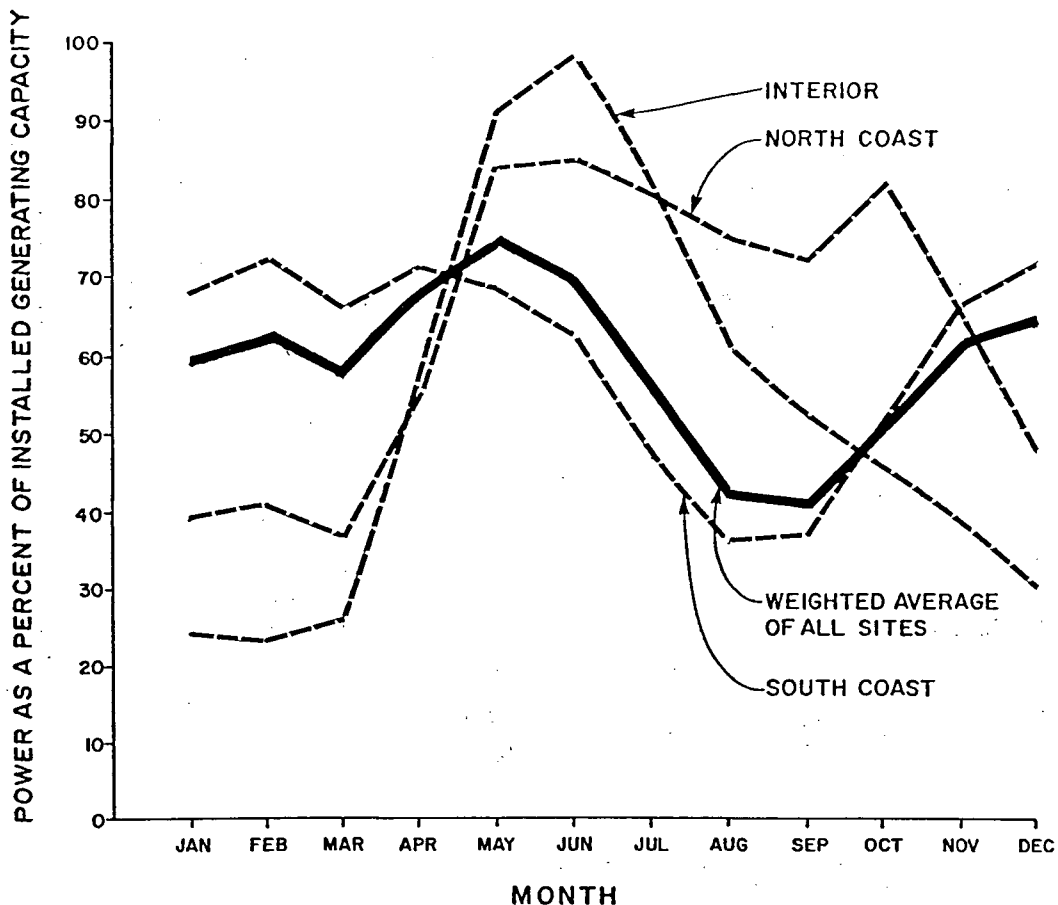


FIRMNESS FACTOR =  $\frac{\text{ANNUAL ENERGY (kWh)}}{\text{INSTALLED CAPACITY (kw)} \times 8760 \text{ hrs}}$

**FIRMNESS FACTORS**

**FIGURE A6-1 : Firmness Factors**

Source: Sigma's "Small Hydro Resource" (1983)



#### VARIATION OF SMALL HYDRO POWER CONTRIBUTION

Note: Generator installed to use mean annual flow, run of river.

#### MEAN MONTHLY POWER OUTPUT AS A PERCENT OF INSTALLED GENERATING CAPABILITY vs. MONTH OF YEAR

FIGURE A6-2 : Variation of Small Hydro Power Output

Source: Sigma's "Small Hydro Resource" (1983)